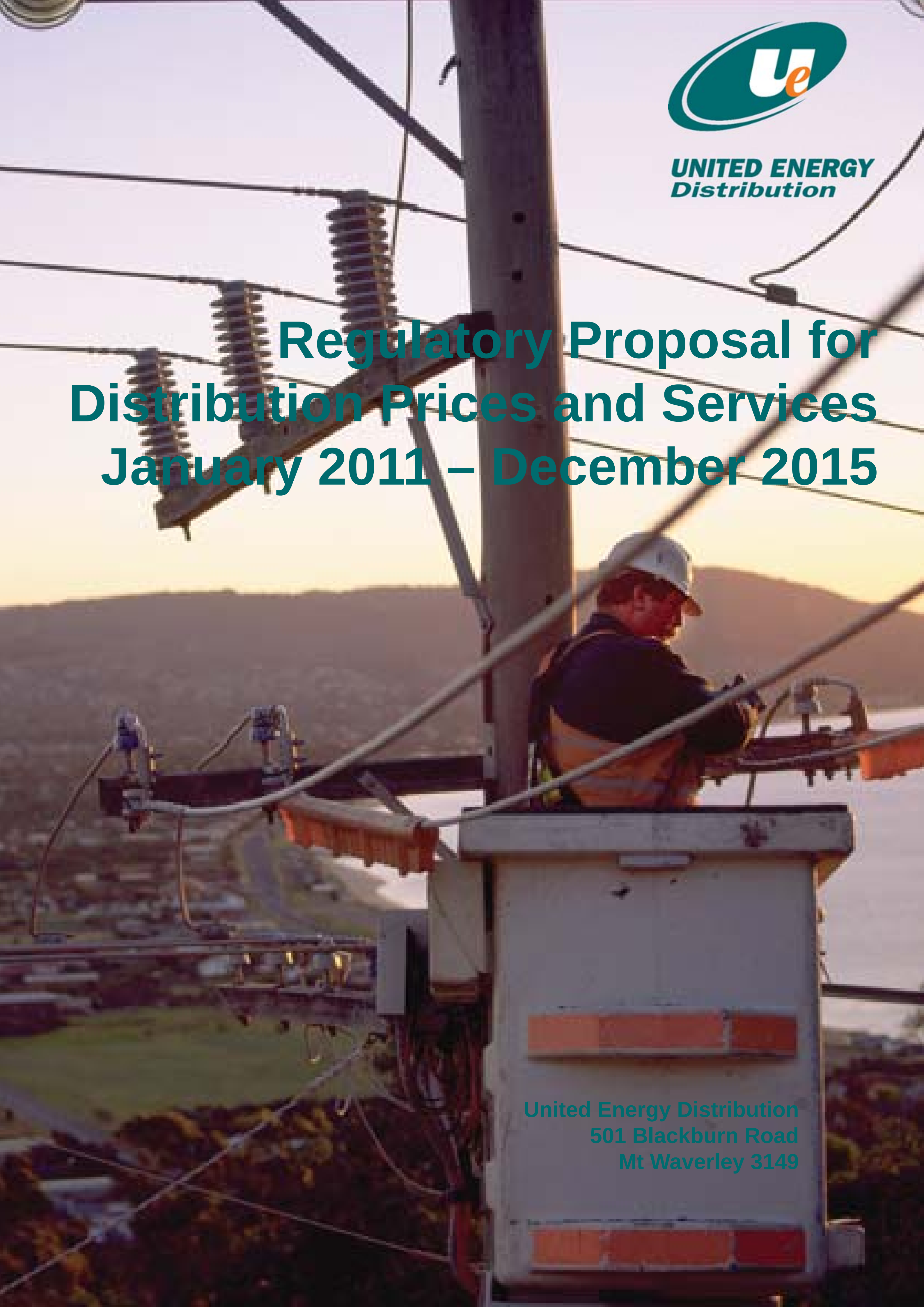

UNITED ENERGY Distribution

Regulatory Proposal for Distribution Prices and Services January 2011 – December 2015

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Executive summary

United Energy Distribution Pty Ltd ("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.

The regulatory arrangements applicable to UED changed on 1 January 2009, when the Australian Energy Regulator ("AER") assumed responsibility for the economic regulation of electricity distribution networks in Victoria. This document is UED's first Regulatory Proposal, submitted to the AER in accordance with the new National Electricity Rules ("the Rules").

In this Regulatory Proposal UED explains and substantiates its proposed price-service package for the period from 1 January 2011 to 31 December 2015. This executive summary highlights the key elements of UED's submission, which are as follows:

- Our recent performance has delivered substantially lower prices and better reliability to customers. Benchmarking shows that the privatised Victorian distribution businesses, and UED in particular, are far more cost efficient, and deliver electricity more reliably to consumers than our Australian peers in South Australia, NSW and Queensland.
- UED is further transforming its business model to establish greater flexibility and to enhance its ability to manage risks as we move into a period of significant change. In addition, UED's transformation will deliver additional efficiency improvements, whilst addressing issues that have arisen with the business model in recent years.
- Our expenditure forecasts are based on a highly competitive public tender process that has been conducted as part of the further restructuring of the business. The results from the tender process confirm that UED's preferred business model is the right one for the company and its customers.
- The issues of climate change, the potential impacts of climate change policy, and aging assets are not only putting an upward pressure on costs, but they are all contributing to a significant uncertainty as to the level of spend that will be required in the outturn. UED reminds the AER of the significant cost reduction that has occurred in our business (and the other Victorian distributors) since privatisation and that as a result there is no 'cushion' in the cost structure of the businesses that can be used to absorb higher than expected costs as we move into this period of uncertainty.
- For the first time since its formation in the mid 1990s, the need for an increased level of investment in the network will mean UED has to raise new debt and equity, rather than being able to fund network investment internally.
- The global financial crisis has had a profound impact on attitudes to risk in the financial markets, and has led to increases in the cost of debt and equity. UED's Regulatory Proposal includes a cost of capital that reflects the actual market conditions that are expected to prevail over the forthcoming period.
- UED's Regulatory Proposal will provide significant benefits to customers by delivering further efficiency improvements despite the significant upward cost pressures that are faced by all network businesses throughout Australia.

- The Regulatory Proposal also provides long term benefits to customers through the progressing the renewal of aging network infrastructure for the future.

UED has delivered lower prices and improved service

- UED has delivered substantial price reductions and service improvements since its establishment in 1995. These outcomes have been achieved through UED's aggressive approach to outsourcing. In contrast to largely in-sourced business models adopted by network businesses in other States, UED has delivered substantially greater efficiency benefits.

- Figure E1 compares the operating costs per customer for a number of distributors across Australia, over the period since 2001. It indicates that by 2001 (5 years after privatisation) UED had established itself as a superior cost performer, as had all of the privatised Victorian distribution businesses. We attribute much of this benefit to aggressive outsourcing strategies.

- Figure E1 also shows that whilst costs have drifted upwards for a number of distributors, UED has maintained its position as a low cost performer.

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

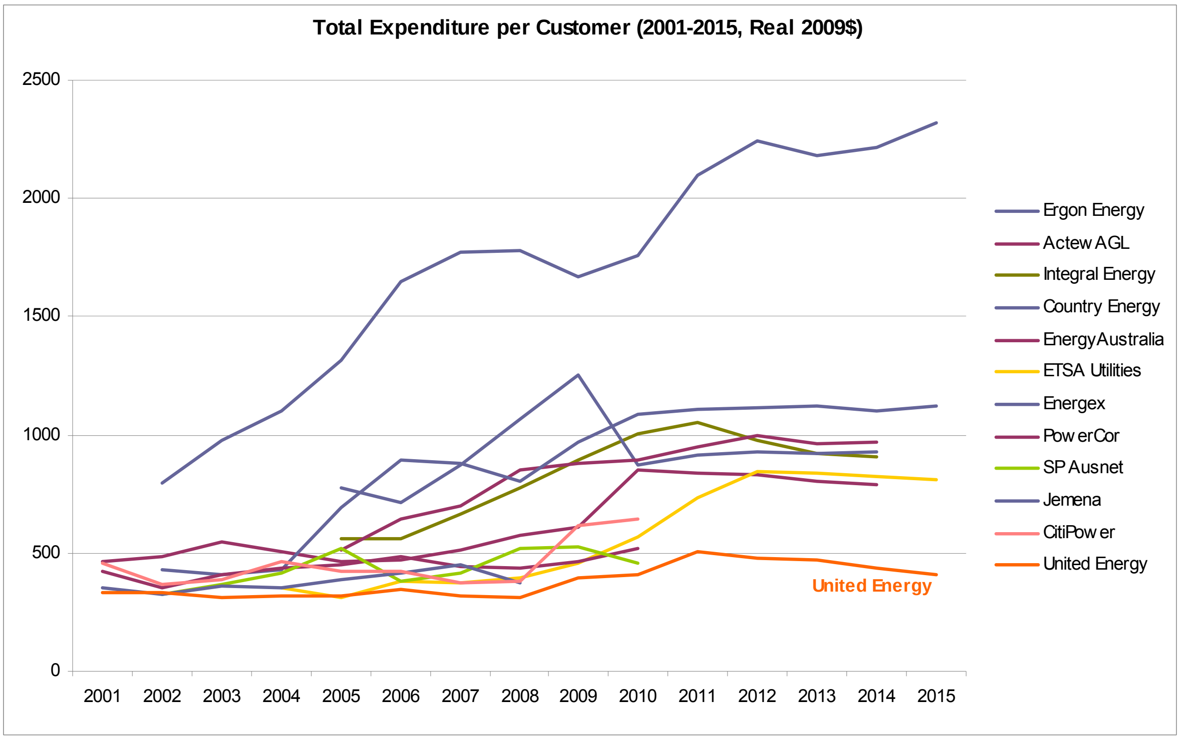
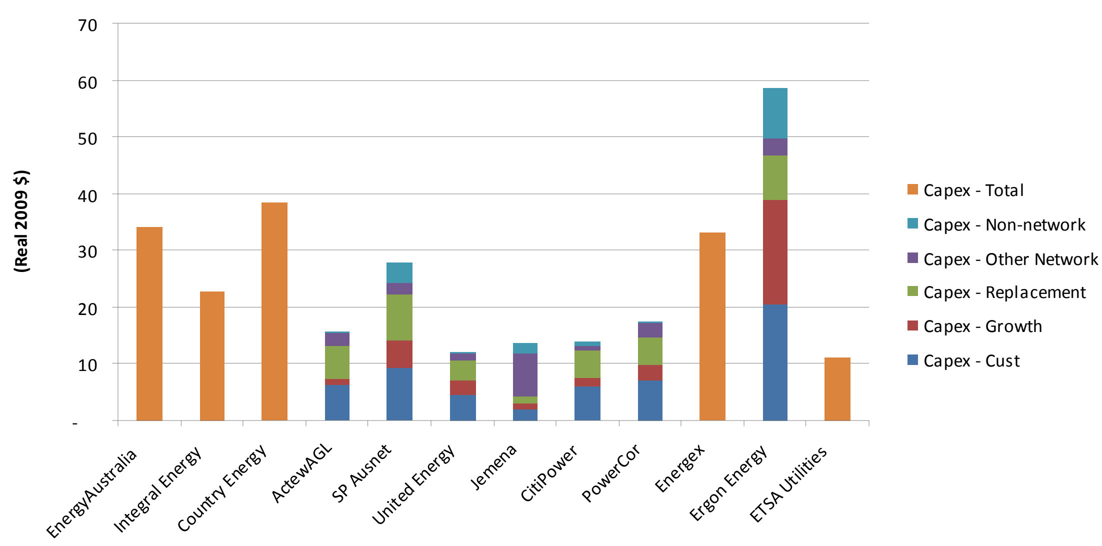


Figure E1 confirms that UED's aggressive approach to outsourcing has delivered substantial benefits to customers. In fact, UED's significant cost efficiencies have led to substantial reductions in network prices.

Figure E2 shows a comparison of capital expenditure per MWh of energy sales, using 2008 data for the same sample of Australian electricity distributors. This comparison indicates that UED is the lowest cost performer in terms of capital expenditure, in some cases more than 50 per cent below the costs incurred by its peers.

Figure E2: Comparison of capital expenditure per MWh for distribution companies

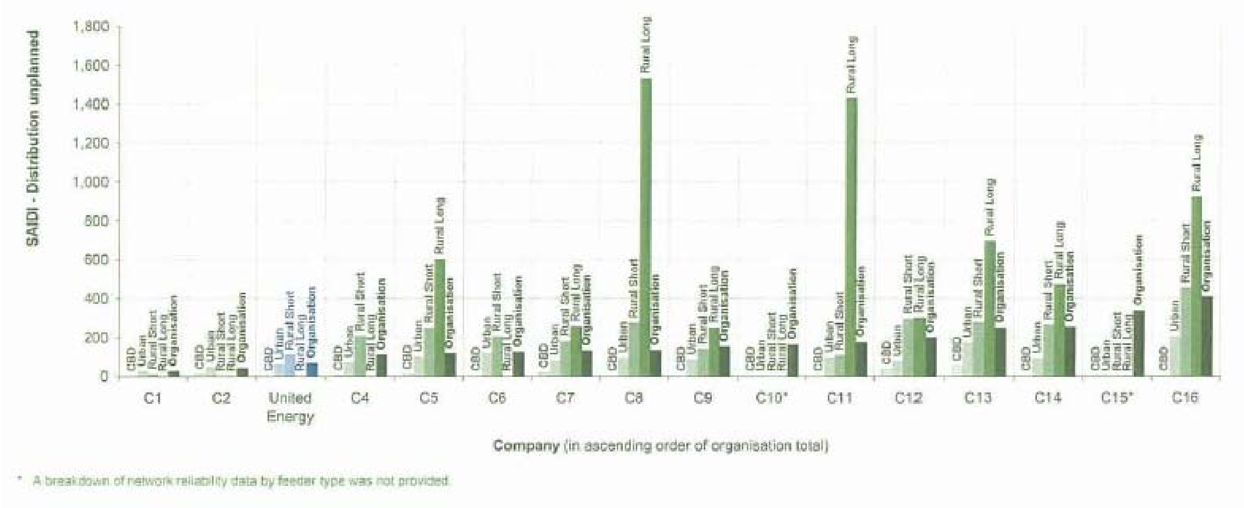


Since 1995 UED's network prices have reduced in real terms by 39 per cent[1]. Importantly, these significant cost savings for customers have not been delivered at the expense of service levels. On the contrary, UED has responded positively to the financial incentives provided by the S-factor scheme to deliver and sustain very substantial improvements in reliability, as measured by SAIDI.

Since 1995, UED has delivered and sustained service improvements. The most recent available data (shown in Figure E3 below) indicates that the reliability of UED's network (when measured in terms of unplanned interruptions) compares very favourably with that of its peers.

[1] **Whilst this Regulatory Proposal puts forward price increases for the coming regulatory period, customers are being asked to pay tariffs which are some 23 per cent lower, on average for the 2011-2015 period, relative to the prices they paid in 1995.**

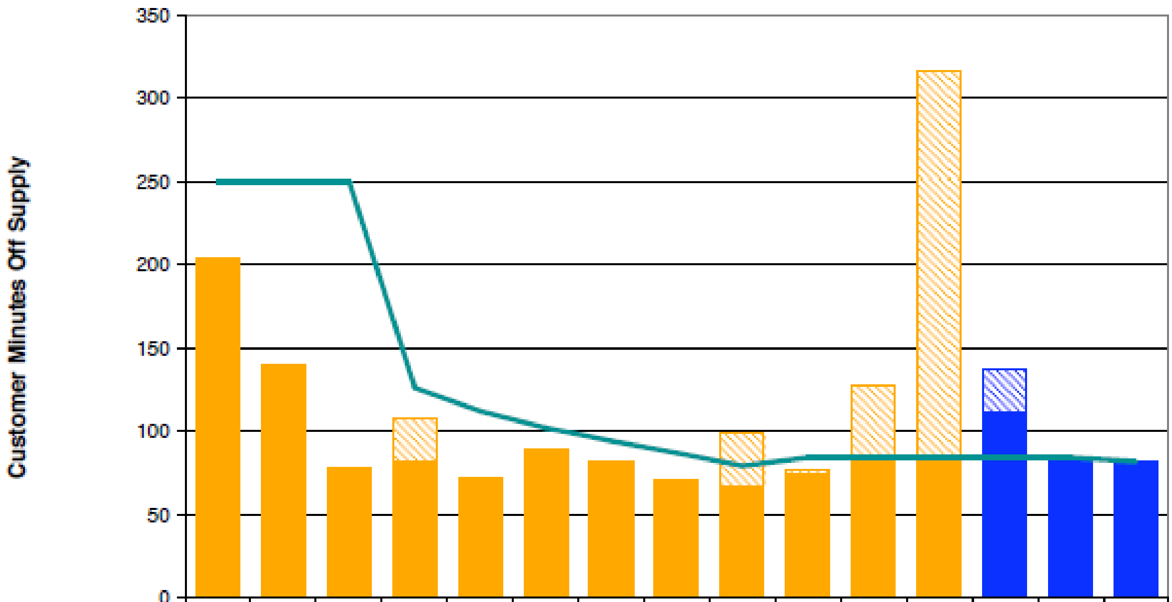
Figure E3: Unplanned SAIDI of a sample of Australian DNSPs for 2007/08



Source: ESAA

Figure E4 below shows the service improvements delivered by UED. However, it also shows the unprecedented effects of storm activity in 2008 and 2009. Whilst the effects of these storms were excluded for the purposes of measuring underlying reliability performance, UED's customers are affected by these types of events. UED therefore faces a challenge in terms of maintaining service levels in the face of climate change.

Figure E4: 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	128	112	102	94	87	79	84	84	84	84	84	82

- As evidenced by the above figure, climate change and extreme weather events are already affecting UED's network performance and the impacts of climate change will be increasingly serious in the future. 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. AECOM has concluded that UED will be impacted by more severe weather events in the forthcoming regulatory period. This will impact reliability performance and require additional expenditure to mitigate these events.

UED is transforming its business model to deliver further efficiencies

UED will commence the new regulatory period with a business model that has already delivered significant cost efficiencies, lower prices and service improvements. UED's current business model is centred on:

- a small management structure that conducts strategic management and corporate governance activities both within and through services provided by its parent entity DUET; and
- a single outsourced contract (the Operating Services Agreement or "OSA") let to Jemena Asset Management ("JAM", formerly Alinta Asset Management) principally on a fixed price basis, for all of UED's direct business operations and a number of corporate and back office functions.

UED's OSA with JAM is due to expire on 30 June 2011.

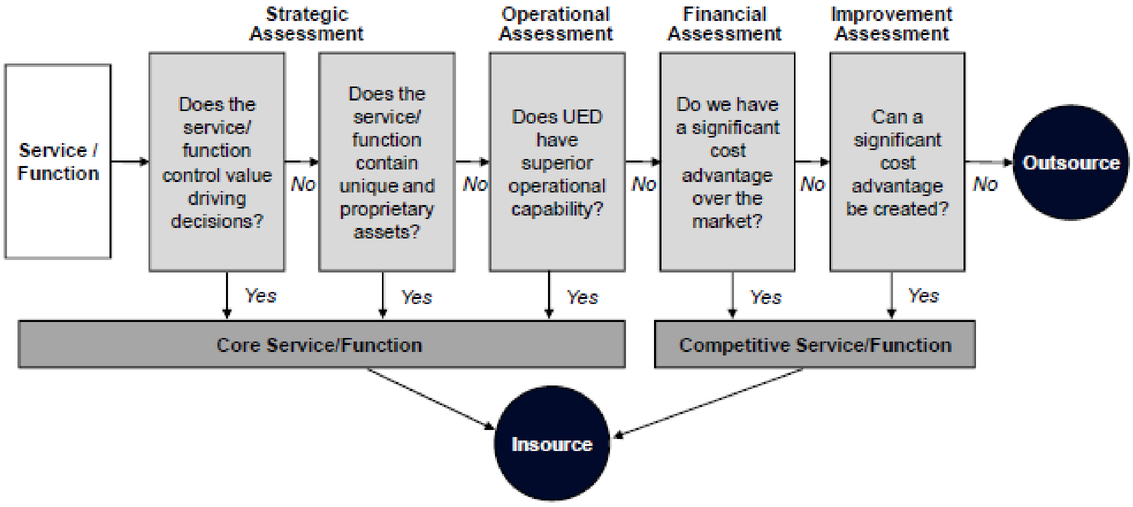
UED's business objectives are to deliver high levels of performance and service with an efficient cost structure. These objectives are consistent with National Electricity Law ("NEL") and Rules requirements, which are naturally focused on the achievement of efficiency. To achieve these objectives, UED has, as noted in further detail below, decided to continue with an outsourced business model, but with some significant changes.

In particular, UED's Board has concluded that its preferred business model should engage one or more consortia which comprise "best of breed" contractors. 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/or international basis, and possess specialist knowledge skills and economies of scale and scope. These best of breed contractors are sought by clients (such as UED) for outsourcing projects, and have a proven track record of winning tenders and delivering benefits to their clients. By engaging best of breed contractors, UED obtains significant benefits in terms of cost and performance compared to the current outsourcing model. In addition to the benefits of engaging best of breed contractors, UED's preferred business model is also expected to:

- reduce UED's reliance on any one contractor, by moving towards an outsourcing model that includes multiple contracts and multiple service providers;
- enable UED to evolve to the adoption of best-practice forms of contract, principally based on a collaborative contracting model;
- avoid contractual arrangements that provide incentives to "over-shoot" - that is, to reduce costs and/or to increase risks to unsustainable levels; and
- ensure high levels of transparency and robust governance arrangements in all contracts entered into by UED for the procurement of business inputs.

In light of the above objectives, UED engaged AT Kearney[2] 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. Although UED's Board wishes to retain an outsourced business model, UED embarked on a systematic assessment to determine which services should be provided within the business. An overview of this make/buy decision framework is provided in Figure E5 below.

Figure E5: "Make/Buy" decision framework overview



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.

UED's expenditure forecasts reflect outcomes from a competitive tender process

To address the Rules requirements, UED's expenditure forecasts for the forthcoming regulatory period must recognise that its current business model will change significantly. For example, in UED's circumstances it would not be appropriate to forecast operating expenditure by using a simple escalation from, say, 2008 actual operating expenditure. Rather UED has recognised that the requirements of the Rules can only be fully complied with if a comprehensive forecast is developed based on a robust and diligent forecasting process that fully recognises all the specific issues and opportunities that face UED's business, assets and customers over the period. UED also recognise that the veracity of its expenditure forecasts and the overall success of Project 7/11 depend on UED conducting a highly competitive, public tender process.

[2] **AT Kearney has invaluable experience in assisting companies with their outsourcing strategies, including the optimal design of contractual terms and conditions.**

Therefore, UED's approach to the tendering process has focussed on minimising entry barriers to potential respondents; avoiding inappropriate risk transfer (with associated inefficient pricing); and creating the foundations for a positive relationship with the future 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 adhered to probity protocols throughout the tender process.

In December 2008, UED commenced a three phased process to identify Turnkey Service Provider(s) to appoint to deliver the services being tendered, and to help UED transition to its new business model. The three stages of this tendering process were:

- Expression of Interest (EOI);
- Request for Proposals (RFP); and
- Target Cost Establishment (TCE).

The purpose of the EOI stage was to identify parties that have the appropriate capacity, capability and expertise. A total of 61 potential suppliers submitted responses to the EOI, of which a total of 36 respondents were assessed as being "Prequalified Respondents" and capable of providing some or all of the services being tendered.

In early April 2009, UED invited the seven EOI respondents short-listed as potential Turnkey Service Providers to submit written proposals in response to the requirements the RFP. After assessing each of the submissions in response to the RFP, each of the consortia was invited to attend separate workshops to receive feedback on their submissions. Each consortium was then provided with the opportunity to revise submissions based on this feedback and to re-submit those submissions for final evaluation. Following further workshops, two consortia were selected to proceed to the TCE stage.

The TCE stage was focused on developing:

- a detailed proposal to UED for the delivery of the transformation of UED's business to the desired end-state;
- a detailed proposal to UED for the delivery of the services outlined within the RFP; and
- a five-year total cost target and margin, with agreed financial and non-financial incentive arrangements.

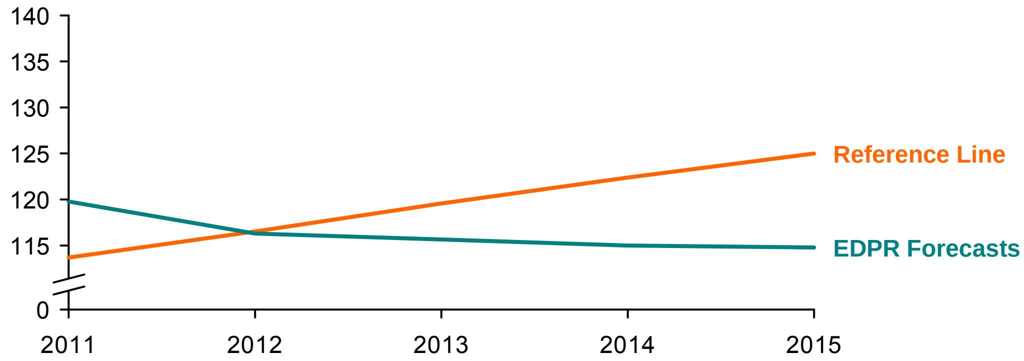
The commitment that the bidders have shown to the process, including incurring significant bid costs, is evidence of the competitiveness of the process.

UED's evaluation of the tender outcomes has validated the Board's decision to embark on a business transformation process. Business transformation processes typically require additional upfront costs in the short-term in order to deliver longer term cost reductions and service improvements. UED's business transformation is no different. UED has identified the need for significant changes in existing business systems and processes in order to deliver better outcomes in terms of:

- cost and service performance;
- risk management; and
- improved governance, including cost transparency and reporting.

Figure E5 shows a comparison of two 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 in the recent tender process.

Figure E6: UED's five year comparisons (OPEX) – DUOS opex only

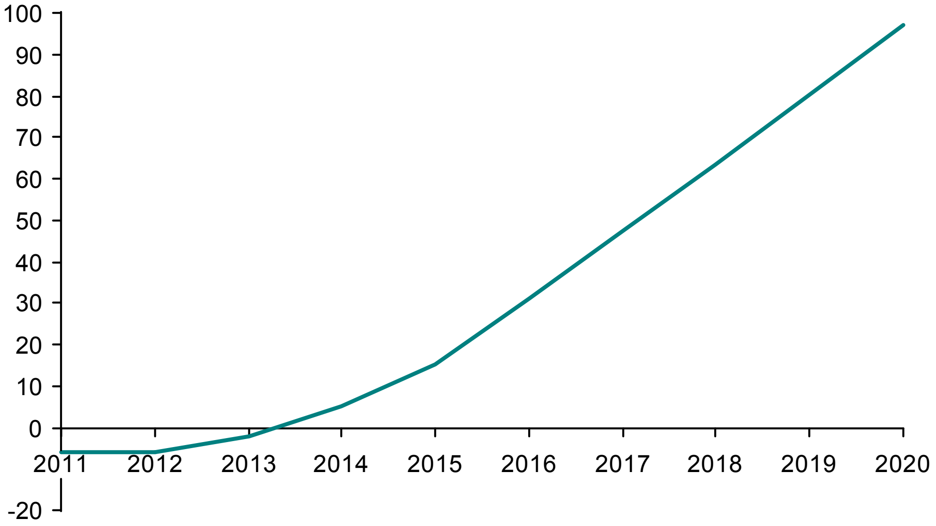


Note: The reference line in figure E5 is calculated based on the actual cost of services in the 2008 and 2009 years projected forward in the light specific known cost changes and externally developed general cost escalator[3].

Figure E6 shows that UED's preferred 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 figure below shows that the payback of operating expenses in a little more than two years from the commencement of the forthcoming regulatory period, further justifying the upfront investments to deliver the new business model. This benefit has been factored into UED's forecasts and will be enjoyed by customers.

[3] **An appendix is attached that details the assumptions supporting the calculation of the reference line.**

Figure E7: New Business Model Operating Expenditure Payback



As noted above, the operating and capital expenditure forecasts in this Regulatory Proposal reflect the market tested bid provided by the lowest cost consortium of contractors. As such, UED's expenditure forecasts comply with the letter and the spirit of the National Electricity Law and the Rules by delivering the most efficient outcome for customers for the forthcoming and subsequent regulatory periods.

Managing an ageing assets base in the face of climate change

In broad terms, UED is required to present capital expenditure plans that:

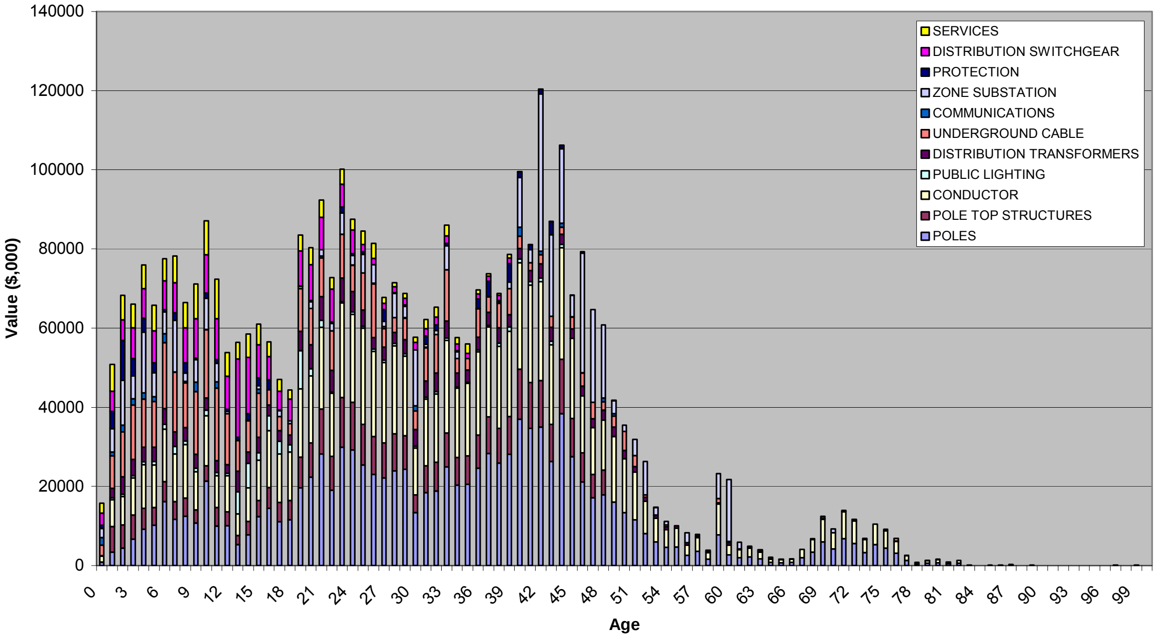
- meet or manage the expected demand for services;
- comply with all applicable regulatory obligations or requirements
- maintain the quality, reliability, safety and security of supply

UED's network planning process has concluded that addressing these requirements will lead to an increase in capital expenditure compared to the current period. Not only has the unit cost of capital expenditure increased in recent years, but environmental factors and network issues also necessitate an increase in the volume of capital expenditure. The key areas of concern relate to:

- Increasing penetration of domestic air conditioning, which is driving growth in summer maximum demand at a rate more than double the growth in energy consumption on average. Heatwave conditions in 2009 led to significant growth in demand for some LV circuits, causing numerous overloads of distribution transformers and low voltage circuits. Whilst customers are clearly becoming more energy conscious over most of the days of the year (evidenced by total consumption in UED area reducing over recent years), recent behaviour indicates that customers are not prepared to forego air conditioning on days of extreme heat (as evidenced by UED's growing maximum demand on hot days).

- 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". Investment in the network accelerated in the late 1950s and reached a peak in the decade between 1960 and 1970 that has not been repeated. The implication of a historical investment peak is a very high prospective replacement peak. During the forthcoming regulatory period (2011-2015) the number and value of the assets that come to their end of life will increase. This unavoidably leads to a requirement to increase the rate of asset replacement in order to maintain reliability at current levels in an environment of more severe weather extremes associated with climate change. The graph of network age profile shown in Figure E8 below indicates the extent of this investment.

Figure E8: UED asset age profile by replacement value



- The impact of 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 of past climatic conditions. The historical approach will no longer be sufficient to maintain network performance under these changing climatic conditions, which are expected to lead to:
  - o periods of extreme temperatures continuing, impacting on the demand for and use of air conditioning and as such driving up the instantaneous maximum demand on the network;
  - o increases in the number of days where extreme winds are experienced, leading to network outages and damage, and consequential adverse impacts on SAIDI and maintenance costs;
  - o a decreasing trend in annual rainfall is projected to continue, increasing on the incidence of mature distressed trees failing at the roots in strong winds and falling across power lines; and
  - o an increase in fire danger due to drought, high temperature and strong winds impacting on the cost of bushfire mitigation measures.
- 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. Immediate initiatives include the increased management of hazardous trees, the

investment in the removal of Single Wire Earth Return (SWER) system, the installation of insulated conductor systems and the minimisation of fire starts through earth fault current reduction.

- Under the Electricity Safety (Network Asset) Regulations, 2009 it will be mandatory for network operators to implement an Electricity Safety Management Scheme (ESMS) within a new safety regulatory framework requiring identification and management of risks associated with the assets to a level that is "As Low As Reasonably Practicable" (ALARP). This change in safety legislation represents a major shift away from previous arrangements, and has prompted UED to accelerate the replacement of aged assets which have a direct potential impact on public safety.

In the early 1990's the SECV embarked on an extensive asset life extension program. UED has continued with this program which includes staking and treating poles rather than replacing them, rebushing transformers rather than replacing them and so on. This successful program has benefitted customers in the form of lower prices, however these extension programs cannot be extended any further. These assets now require replacement and this unavoidable requirement is a driver of the increased capital expenditure forecasts in the forthcoming period.

The forthcoming regulatory period will therefore see a substantial increase in capital expenditure to address these emerging network issues and to enable UED to continue to deliver reliable services to our customers. There is little doubt that even with the significant increases in capital expenditure set out in this Regulatory Proposal, there is still a possibility that actual capital expenditure will exceed the projections presented here.

Financing new investment

The cost of capital is a critical element in the AER's revenue determination process. It is widely acknowledged that there is a significant degree of imprecision and subjectivity involved in the estimation of the regulatory benchmark cost of capital, and there is certainly no one objectively determinable "correct" estimate of the cost of capital That said, it is worth noting here that the actual cost of capital to a particular business – i.e. the cost of equity and debt required to finance its activities - can be observed when the business raises new capital, and as noted in further detail below, the cost of raising capital is now well above the level implied by the AER's recent decisions. In this context it is also worth emphasising that policy makers have recognised that very large costs to society as a whole would arise if regulators set the cost of capital at a level that is insufficient to encourage new investment in infrastructure.

The global financial crisis has resulted in a sharp increase in the cost of capital, with capital markets effectively closed at the height of the crisis following the collapse of Lehman Brothers in September 2008. While access to credit has gradually improved, the cost of debt is now significantly higher than prior to the crisis and access to financing is also more limited. There is no doubt that the cost of equity is also significantly higher, as equity holders like debt holders have also reappraised their appetite for and pricing of risk.

Delivery of the new investment required to ensure the achievement of the capital and operating expenditure objectives set out in the Rules will not be possible unless the AER's determination on the cost of capital takes account of current market conditions and the prevailing cost of capital. In this regard, UED is particularly conscious of the need to revisit the market risk premium (MRP) set by the AER in its Statement of Regulatory Intent (SORI). UED does not accept that an MRP of 6.5 per cent in the AER's SORI is likely to reflect the actual MRP over the forthcoming regulatory period. In fact, UED provides new evidence in this submission from Professors Officer and Bishop which indicates that the forward looking MRP is 12.0 per cent per annum and that the best estimate for the MRP over the forthcoming regulatory period is 8.0 per cent per annum.

UED has also obtained evidence from Associate Professor Skeels which concludes that the value of gamma adopted by the AER in its SORI should be amended to 0.5 from 0.65. Apart from the adjustments to these two elements, UED accepts the parameter values in the SORI. Table E1 below shows the WACC parameter values adopted by UED for the purpose of this Regulatory Proposal.

Table E1: UED's proposed WACC parameter values for this Regulatory Proposal

Parameter	Value/Methodology
Gearing	60% debt to total assets
Beta (β)	0.8
MRP	8.0%
Measurement period for the nominal risk free rate and Debt Risk Premium	The 15 business day period commencing on 1 October 2009 and ending on 21 October 2009, for the purpose of this Regulatory Proposal. The measurement period to be applied in the final determination has been proposed by UED on a confidential basis in accordance with the provisions set out in Clause 6.5.2(c)(2)(iii).
Nominal Risk Free Rate	5.47%
Expected inflation	2.44%
Real Risk Free Rate	2.96%
Debt Risk Premium	4.71% (471 basis points)
Gamma	0.5
Nominal Vanilla WACC	10.86%
Real vanilla WACC	8.22%

Revenue and price outcomes for customers

Table E2 below shows UED's proposed increase in average prices for the forthcoming regulatory period, and Table E3 explains the principal reasons for the proposed increases.

Table E2: UED's proposed real price increases for the forthcoming regulatory period

2011	2012	2013	2014	2015
16.6%	4.0%	4.0%	4.0%	4.0%

Table E3: Principal reasons for UED's real price increases

Building block	Price change effect	Discussion
Return on capital	Approximately 12%	The cost of capital in this proposal is 8.22% compared to current WACC of 5.90%. The increase is driven primarily by a higher debt risk premium, reflecting market conditions.
Operating expenditure	Approximately 5%	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 power (generation);
- the cost of bulk transportation (transmission);
- the cost of distribution (distribution); and
- billing (retail costs).

This 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 E4 below:

Table E4: Analysis of impact of UED's 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	16.6%
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

1.1 Purpose

UED is one of five electricity distribution businesses operating under licence[4] 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

UED's business performance and organisational structure has been transformed following the disaggregation and privatisation of the Victorian electricity supply industry in 1994. Customers have benefited significantly from these efficiencies. In fact, UED's network prices today are 35 per cent lower compared to 1997 (39 per cent since 1994), whilst for NSW distributors the average decrease over the same period is only 14 per cent. 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 this Regulatory Proposal for the forthcoming regulatory period, which will still be some 17 per cent lower in 2014 compared to 1997. The combined effect of the NSW price increases

4 **UED's electricity distribution licence is issued by the Essential Services Commission Victoria, pursuant to the Essential Services Commission Act 2001 and the Electricity Industry Act 2000.**

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[5].

From 1 January 2009, responsibility for the regulation of electricity distribution networks in Victoria transferred from the Essential Services Commission ("ESC") to the Australian Energy Regulator ("AER"). In accordance with the the Rules[6], UED is required to submit its Regulatory Proposal for the period from 1 January 2011 to 31 December 2015. This submission is UED's Regulatory Proposal, and it outlines a price-service offering which builds upon and consolidates the very substantial efficiency and service improvements already achieved by the company since it was privatised.

Importantly, UED's Regulatory Proposal explains the next phase of UED's business transformation process, and describes and substantiates the company's expenditure plans for the forthcoming regulatory period. UED's expenditure and service delivery plans for the forthcoming regulatory period will maintain the company's position as one of the leading electricity distribution companies in Australia.

It is important to note that UED's expenditure plans - and in particular its capital investment proposals - are aimed at ensuring the company is fully capable of delivering its planned service outcomes over the forthcoming period. UED's ability to deliver its target service outcomes is therefore dependent upon the AER's acceptance of the company's expenditure proposals. Over the forthcoming period, UED's service delivery capability will also be dependent upon the company's access to the new capital that will be required to fund its capital investment proposals. The company's access to funding - and hence its ability to deliver planned service outcomes - is particularly dependent on the AER's acceptance of the WACC and depreciation proposals detailed in this submission.

In preparing UED's Regulatory Proposal, every effort has been made to ensure that UED complies with the requirements of the Rules and the AER's regulatory guidelines and orders, including the Regulatory Information Notice and accompanying templates. UED is confident that this submission complies fully with all of these regulatory requirements. The submission contains helpful cross-references to the relevant regulatory provisions so that regulatory compliance can be demonstrated explicitly.

1.2 Contents of this Regulatory Proposal

The contents of this Regulatory Proposal are mandated by clause 6.8.2(c) of the Rules, which states that the Regulatory Proposal must include (but need not be limited to) the following elements:

(1) a classification proposal, which shows how the distribution services should be classified for regulatory purposes;

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[5] **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.**

[6] **AER, Electricity distribution network service providers - Efficiency benefit sharing scheme, June 2008.**

(2) a building block proposal for those "direct control services" that are classified as "standard control services";

(3) the application of the control mechanism (as set out in the AER's Framework and Approach Paper) for those "direct control services" that are classified as "alternative control services";

(4) indicative prices for "direct control services" for each year of the regulatory control period;

(5) a proposed negotiating framework for services classified under the proposal as "negotiated distribution services"; and

(6) an indication of the parts of the proposal that UED claims to be confidential and wants suppressed from publication on that ground.

In relation to the above provision relating to confidentiality ((6)), UED will ensure that the public version of this Regulatory Proposal identifies any information that has been (or will be) provided to the AER on a confidential basis. UED welcomes the publication of this Regulatory Proposal and any feedback from stakeholders during the AER's consultation process.

The classification of distribution services is explained in detail in Chapter 12 of this submission. In advance of that detailed explanation, it is worth noting that UED's proposed classification is consistent with the AER's proposed approach in its Framework and Approach Paper[7] with the exception of connection capital. Connection capital has been classified consistent with the approach currently in place and consistent with ESC Guideline No. 14, noting that this guideline is binding on all Victorian electricity distributors. In particular, the AER concluded in that paper that its likely approach is to classify services as follows:

- standard control services (being subject to building block regulation) should include network services, which includes distribution use of system (DUOS) services;
- alternative control services (being subject to a CPI-X price cap) should include certain excluded distribution services and prescribed metering services (unmetered supplies) currently provided by the Victorian DNSP's as follows:
    - connection (energisation) services;
    - metering services (unmetered supplies);
    - public lighting services;
    - fee based services; and
    - quoted services.

[7] **AER, *Framework and Approach Paper for Victorian electricity distribution regulation*, May 2009, page 3. It should be noted that the AER's classification of services is not binding on the AER or the distribution companies.**

- negotiated distribution services (being subject to UED's negotiating framework) include connection and augmentation works for new customer connections; alteration and relocation of existing DNSP public lighting assets; and new public lighting.

The AER also indicated in its Framework and Approach Paper that the following distribution services will not be classified for the purposes of chapter 6 of the Rules[8]:

- AMI services, which will be regulated under the November 2008 AMI Order in Council;
- metering provision services and metering data provision services for type 1 to type 4 metering installations;
- metering services provided to customers with annual consumption greater than 160 MWh that have either type 5 manually read interval meters or type 6 manually read accumulation meters; and
- the installation and maintenance of watchman (security) lights.

The costs and revenues associated with the provision of the above services are therefore not relevant to this submission.

1.3 Duration of this Regulatory Proposal

In accordance with the provisions set out in clause 6.3.2(b) of the Rules, the regulatory control period to which this Regulatory Proposal applies is the five year period commencing on 1 January 2011 and ceasing on 31 December 2015.

1.4 Structure of this submission

The remainder of UED's Regulatory Proposal is structured as follows:

- Chapter 2 benchmarks UED's current business performance and examines its service performance under the ESC's S-factor scheme. It concludes with a commentary on the future outlook for services and prices.
- Chapter 3 explains that UED management and the UED Board have concluded that sustaining existing business performance and current levels of reliability can only be achieved if UED's existing outsourcing model is substantially revised. It explains UED's transition towards its preferred business model and the benefits that the change is expected to deliver.
- Chapter 4 describes the planning undertaken by UED to ensure that the company is able to satisfy customer demand and to meet its compliance obligations. Together, these service outputs are important cost drivers that affect UED's expenditure plans for the forthcoming regulatory period.
- Chapters 5 to 11 provide detailed cost information relating to the provision of distribution network services, which will continue to be subject to building block

[8] A note to clause 6.2.1 of the Rules states: "If the AER decides against classifying a distribution service, the service is not regulated under the Rules".

regulation. Each of these Chapters addresses the relevant Rules requirements and AER guidelines.

 - Chapter 5 sets out UED's operating expenditure plans and forecasts.
 - Chapter 6 sets out UED's capital expenditure plans and forecasts.
 - Chapter 7 explains UED's approach to depreciation for the forthcoming regulatory period.
 - Chapter 8 presents UED's calculation of the regulatory asset base.
 - Chapter 9 sets out UED's estimate of the cost of capital, noting the requirements set out in the AER's Statement of Regulatory Intent in relation to the cost of capital.
 - Chapter 10 sets out information relating to 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 presents the total revenue and X factor calculation for those services that are subject to building block regulation.

- Chapter 12 sets out UED's proposed classification of distribution services, taking particular note of the AER's Framework and Approach Paper.
- Chapter 13 presents detailed information relating to UED's energy, peak demand and customer number forecasts.
- Chapter 14 sets out information relating to UED's tariff strategy for the forthcoming regulatory period and the proposed changes in tariffs, having regard to the expenditure plans detailed in this submission.
- Chapter 15 provides details of the proposed control mechanisms that are to be applied to standard control services and alternative control services.
- Chapter 16 sets out UED's proposals regarding the application of the service target performance incentive scheme for the forthcoming regulatory period.
- Chapter 17 details UED's proposals regarding the application of the efficiency benefit sharing scheme for the forthcoming regulatory period.
- Chapter 18 provides details of UED's proposals regarding the application of the demand management incentive scheme for the forthcoming regulatory period.
- Chapter 19 sets out UED's proposed pass through events, which provide for certain unexpected cost increases (or decreases) to be recovered from (or returned to) UED's customers.
- Chapter 20 sets out UED's negotiating framework, which satisfies the Rules requirements and which provides a basis for the determination of negotiated distribution services on fair and reasonable terms.

2. Background: Our efficient performance and business transformation

Key messages

- The National Electricity Objective requires the promotion of efficiency in investment, and operation and use of electricity services.
- The Rules also emphasise efficiency by, for example, requiring distribution network companies to present expenditure forecasts that reasonably reflect efficient costs.
- 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.
- The significant use of outsourcing in Victoria since privatisation has been the key catalyst for the Victorian distributors achieving substantially greater efficiency benefits than the largely in-sourced business models adopted by their peers, especially in New South Wales and Queensland.
- Benchmarking demonstrates that UED is already an efficient service provider. Comparisons of cost projections of a large sample of Australian electricity distributors show that UED is expected to remain an efficient, low cost performer.
- In spite of its very strong performance, UED has not been able to sustain the record high level of network reliability performance it achieved in 2004. This decline in service performance was forecast by UED in a detailed simulation exercise in 2005.
- UED is embarking on the next phase of its business model, which aims to consolidate the efficiency improvements delivered to date, as well as providing increased flexibility for the future, and addressing risk management and regulatory issues that have emerged under the present business model.
- With the assistance of specialist advisors AT Kearney, further business transformation initiatives presently underway (termed "Project 7/11") will lead to UED seeking to engage of best-of-breed service providers through a competitive tendering process. Under this initiative, UED will also adopt best practice contractual arrangements that deliver cost transparency, flexibility and strengthened governance arrangements.
- The outcome of the tender process is reflected in UED's expenditure plans and forecasts that are described in this Regulatory Proposal. UED's expenditure forecasts reflect a comprehensive, accurate and up-to-date assessment of the efficient costs of achieving the operating and capital expenditure objectives, in accordance with clauses 6.5.6 and 6.5.7 of the Rules.

2.1 Regulatory requirements and chapter structure

The concept of efficiency is embodied in the national electricity objective and various provisions in the Rules that are relevant to UED's Revenue Proposal. The national electricity objective[9] is:

> " to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to —
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

Clause 6.5.6(c) of the Rules states that the AER must accept the distribution network service provider's forecast operating expenditure for the regulatory control period reasonably reflects the "operating expenditure criteria", which are:

(1) the efficient costs of achieving the operating expenditure objectives; and

(2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

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.

A similar focus on efficiency applies in relation to capital expenditure. In particular, similar Rules provisions[10] to those outlined above also apply in relation to forecast capital expenditure.

In light of these provisions and their emphasis on efficiency, the remainder of this chapter is structured as follows:

- Section 2.2 and 2.3 examine UED's recent cost and service performance respectively. The data presented in these sections demonstrates that UED has delivered substantial price reductions and service improvements since its establishment in 1995. High-level benchmarking with its peers in NSW and Queensland also indicates that UED is a superior cost performer.

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[9] **The national electricity objective is set out in Section 7 of the National Electricity Law (NEL). Section 16(1)(a) of the NEL requires the AER to have regard to the national electricity objective in performing or exercising an economic regulatory function or power.**

[10] **Clause 6.5.7(c)(1) and clauses 6.5.7(e)(4) and (5) apply in relation to capital expenditure forecasts.**

- Section 2.4 concludes the chapter by presenting an overview of the outlook for service standards and prices for the forthcoming regulatory period.

2.2 Cost and price performance

Since its formation in 1995, UED has delivered very substantial price reductions to its customers. In real terms, UED's distribution charges to a typical domestic customer are now 39 per cent lower than in 1995. This substantial reduction in distribution charges has been driven by privatisation of the Victorian industry and the resulting cost reduction strategies of the privatised businesses. Outsourcing has played a key role in those cost reduction strategies. As a result, the cost performance of the Victorian electricity industry is superior to that achieved by network service providers in other states as demonstrated in Figure 1-1 below.

In 2003, UED aggressively extended its use of an outsourcing business model service, as a mechanism for driving efficiencies. UED's experience indicates that:

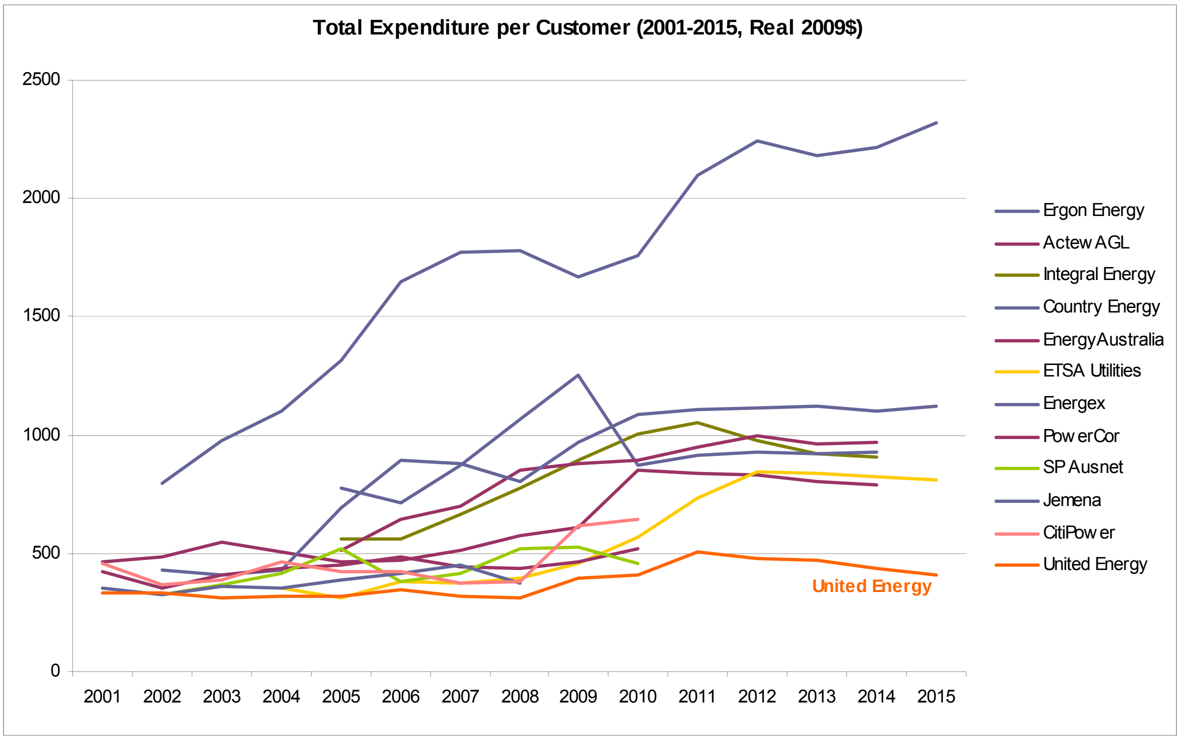
- for an electricity distribution network business, aggressive outsourcing is likely to prove most effective in enabling the rapid identification and execution and retention of efficiency improvements; and
- the alternative approach of delivering efficiency savings within the business through incremental improvements is less likely to enable the identification and achievement of the lowest efficient cost of providing services, and this has certainly proven to be the case.

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 time series data for total expenditure per customer. UED draws the following conclusions from Figure 2.1:

- By 2001 (5 years after privatisation) UED had established itself as a superior cost performer, as had all of the privatised Victorian distribution businesses. We attribute much of this benefit to aggressive outsourcing strategies.
- Whilst costs have drifted upwards for a number of distributors, UED has maintained its position as a low cost performer.

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



Source: SKM DNSP Benchmarking Measures.

Figure 2-2 shows a comparison of capital expenditure per MWh of energy sales, using 2008 data for the same sample of Australian electricity distributors, while Figure 2-3 shows a comparison of capital expenditure per customer. These comparisons indicate that UED is the lowest cost performer in terms of capital expenditure, and in some cases more than 50 per cent lower than its peers.

Figure 2-2: Comparison of capital expenditure per MWh for distribution companies

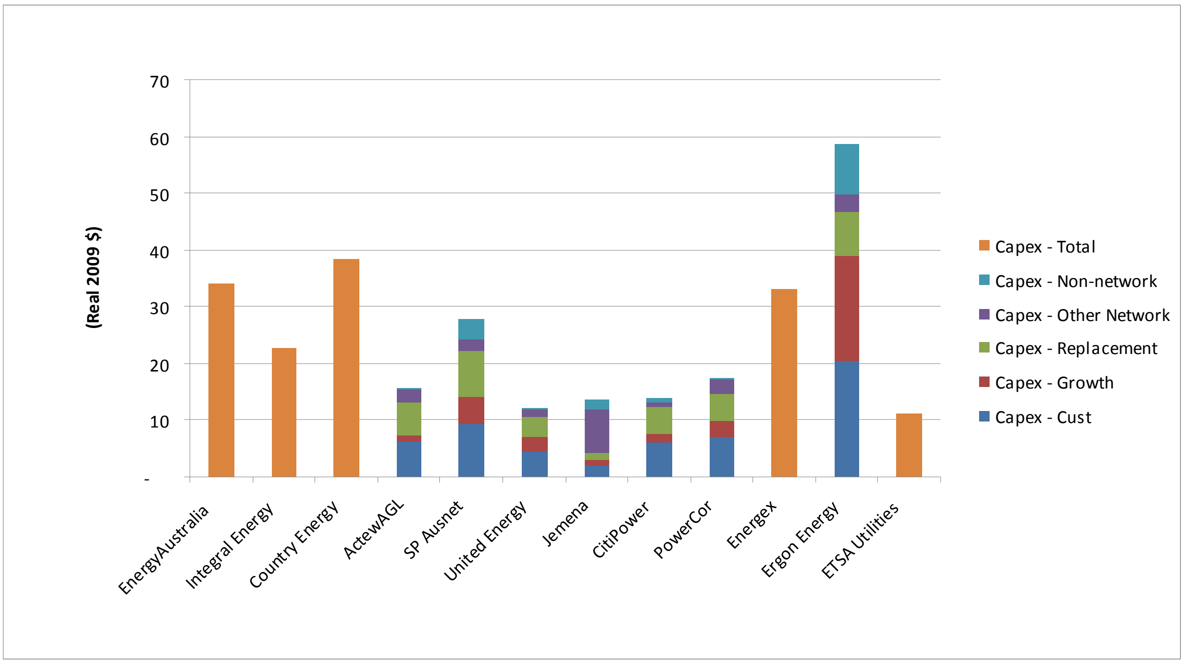
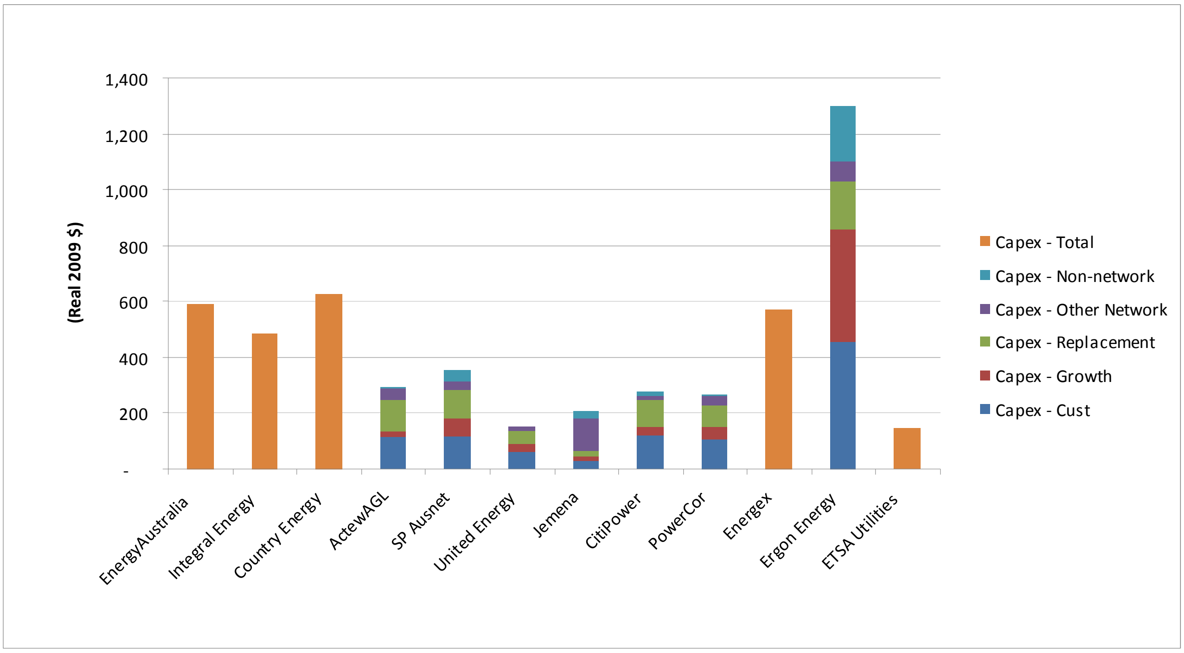


Figure 2-3: Comparison of capital expenditure per customer for distribution companies



Customers have benefited significantly from these efficiencies. In fact, UED's network prices today are 39 per cent lower than they were in 1995, in real terms (35 per cent compared to 1997). In comparison the average decrease over the 1997 – 2008 period for NSW distributors is only 14 per cent. 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 this Regulatory Proposal for the forthcoming regulatory period, which will still be some 17 per cent lower 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[11].

The average residential customer in UED's distribution region territory is will be required to pay $338/year for electricity distribution based on the 2011 tariffs submitted in this Proposal[12]. If that same customer was resident in New South Wales they would pay in a range from approximately $589 per year [13] to $689 per year[14]. The charges that the same customer would pay if a resident in any of the other three eastern states is also well higher than the charges applicable in the UED area or in Victoria.

The recent upward cost pressures in NSW have been reflected nationwide as network companies address the twin challenges of growing demand and aging assets. Whilst UED faces similar issues for the forthcoming period, its network charges will remain highly competitive compared with its peers.

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.

The correlation between the outsourcing strategies of the Victorian businesses and costs efficiency is also noted, and UED has drawn on this evidence (among other things) in deciding to continue with a principally outsourced model going forward.

UED's expenditure plans and cost forecasts for the forthcoming regulatory period indicate that the company's customers will continue to benefit from lower prices and better service. As discussed in 2.3 below, UED is embarking on the next phase of its business model, which aims to consolidate the improvements delivered to date, by engaging best-of-breed service providers through a competitive tendering process.

However, it is not possible to maintain the same rate of price reduction and service improvement now that the principal opportunities for efficiency improvements have been exploited. This observation is best illustrated by a more detailed examination of UED's service performance, which is set out in section 2.3 below.

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[11] 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.

[12] United Energy's residential customer tariffs are at the average of residential tariffs for the five Victorian distributors.

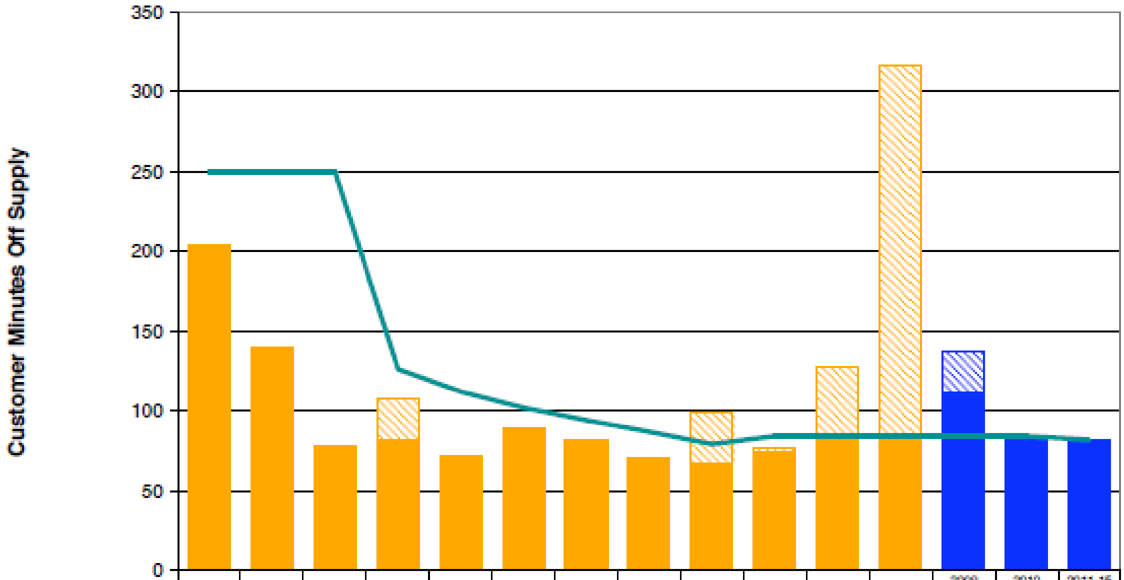
[13] Energy Australia Network Pricing Proposal (revised), May 2009, page 53

[14] Country Energy annual network prices report 09/10, page 9

2.3 Service performance

UED's capital and maintenance programs have consistently focused on improving the level of supply reliability to customers. UED's focus on reliability improvements has been reinforced by the ESC's S-factor scheme, which has provided financial incentives to improve performance. As illustrated in Figure 2-4 below, UED delivered very substantial improvements in SAIDI from 1998-2005.

Figure 2-4: 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	128	112	102	94	87	79	84	84	84	84	84	82

Figure 2-4 above shows that over the 2001-2005 regulatory period, UED delivered a level of reliability (as measured by SAIDI) substantially better than that required by the performance benchmarks. UED's performance improvements over the period were worth approximately $45 million to customers compared to the ESC's benchmarks.[15]

During its 2005 determination, the ESC imposed a significantly more challenging S-factor scheme, with substantially increased incentive rates that apply when performance is better or worse than benchmark. In 2005 the revised S-factor scheme created a significant financial exposure for UED because it provided for heavy financial penalties if UED could not maintain the substantial improvements in service performance that had been achieved in prior regulatory periods.

[15] **The reductions in the level of customer minutes off supply (compared to the regulatory benchmark) in each year equates to a reduction in unserved energy of 1500 MWh. Valuing this reduction in unserved energy at the marginal cost of unserved energy to consumers (approximately $30,000 per MWh in 2005) implies an aggregate saving to customers of $45 million over the 2001-05 regulatory period.**

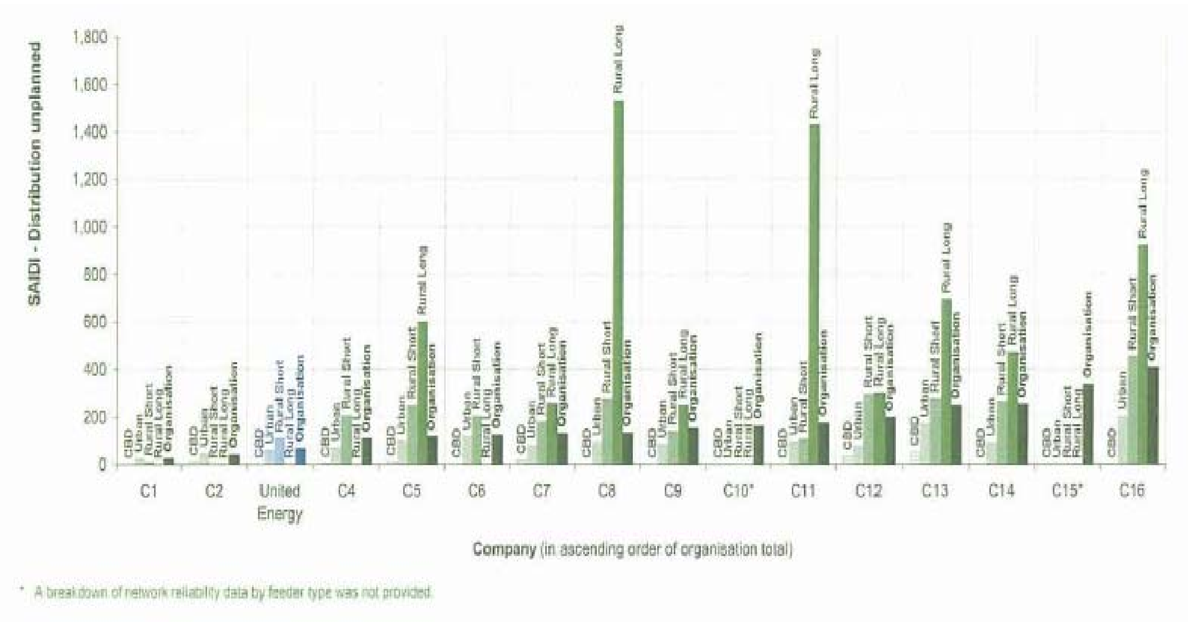
In a submission to the ESC on the design of the S-factor scheme[16], UED explained that its network modelling simulations showed that the reliability enjoyed by UED customers in 2004 and 2005 was at an all-time high. UED expressed concern that the new S-factor scheme adopted 2004 actual performance as a benchmark, even though:

- actual 2004 SAIDI performance is 52 minutes, whereas the 50th percentile is 61 minutes; and
- only 60 out of the next 1,000 simulations delivered an improvement on the 2004 SAIDI performance.

Unfortunately, recent reliability performance on UED's network has proven UED's simulation exercise and the concerns expressed during the design phase of the 2005 S-factor scheme. In 2007, UED's SAIDI was 61.4 minutes, which is practically identical to the 50th percentile estimated in the earlier simulations. The application of a more onerous penalty regime under the ESC's strengthened S-factor scheme in 2005 has led the company to incur substantial penalties as a result of reliability falling below the record performance achieved in 2004. UED is naturally disappointed in this outcome. Although UED achieved median SAIDI performance in 2007 customers received compensation through the S-factor scheme.

Figure 2-5 below shows UED's unplanned SAIDI by feeder category for 2007/08 alongside that of other Australian electricity distributors. This data is sourced from a study prepared by the Electricity Supply Association of Australia. The data indicates that notwithstanding the considerations noted above, the reliability of UED's network (when measured in terms of unplanned interruptions) still compares very favourably with that of its peers.

Figure 2-5: Unplanned SAIDI of a sample of Australian DNSPs for 2007/08



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

Source: ESAA

In addition to receiving benefits under the S-factor scheme, UED's customers have also benefited from an extended GSL scheme, which provides the company with clear financial incentives to address persistent service problems. The GSL scheme provides individual customers with compensation in the event that UED does not achieve defined service commitments. UED continues to work hard to ensure that customers receive appropriate levels of service and thereby also minimise GSL payments.

2.4 Outlook for the forthcoming regulatory period

During the forthcoming regulatory period, UED will continue to focus on maintaining the present high levels of service, and to deliver further improvements where it is feasible and economic to do so. Possible areas for improvement include:

- reliability performance in the areas served by the worst performing feeders;
- power quality; and
- reducing the number of interruptions that customers experience.

Unfortunately, however, 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. These expected effects expose UED and its customers to an increased risk of periodic interruptions in supply. In fact, UED's current analysis indicates that there is very limited scope for further substantial reliability improvements to be delivered cost-effectively. However, the structure of the Rules and the AER's Service Target Performance Incentive Scheme ("STPIS") requires UED to maintain or improve reliability levels.

Therefore UED has proposed a capital expenditure program that maintains the present levels of reliability and quality, as well as mitigating the impacts of forecast climate change events that are expected to affect UED's reliability. Mitigating and responding to the adverse effects of climate change is also expected to place upward pressure on the company's operating expenditure requirements. The expected impacts of climate change on future costs and service standards are reflected in the proposals set out in this submission. UED is proposing 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.

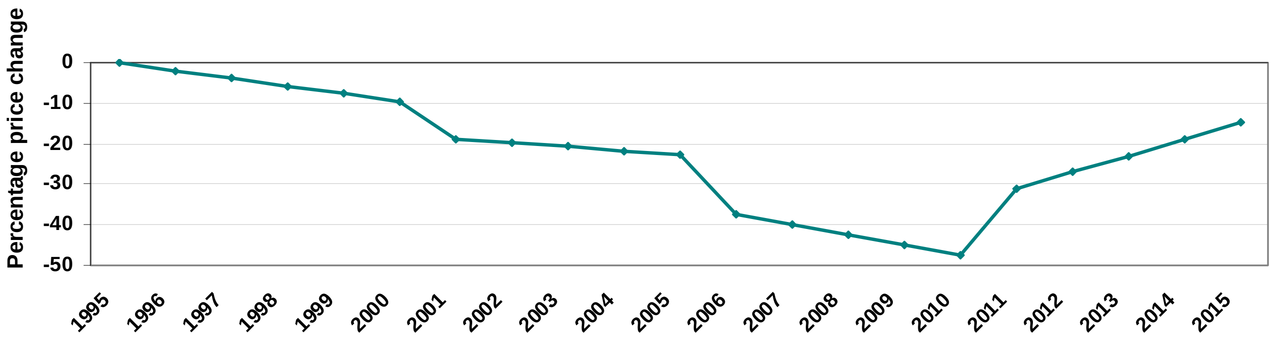
It is noteworthy that the single largest contributing factor for this price increase relate to the cost of capital. Of the 16.6 per cent increase, 12.1 per cent is attributable to the cost of capital. This increase reflects the increased cost of funds in the market and is explained in detail in chapter 9.

Table 2-1: Average price increase 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 2-6) shows the cumulative price changes since 1995.

Figure 2-6: Cumulative price changes, 1995 - 2010



The resultant 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

3. UED's business model and business transformation

Key messages

- UED's current business model has delivered significant cost efficiencies to date. Despite these efficiencies, UED is undertaking a business transformation project to lock in the benefits already achieved, establish greater business flexibility to best manage future change and risk, and deliver a better value proposition to our customers.
- UED is strengthening its internal management resources (involving returning some previously outsourced functions to within the business) so as to provide greater strategic management capability; drive the transformation process; address known issues; and to improve governance and capability to manage change and risk.
- UED has completed a competitive tender to select best of breed contractors to implement the restructure and to provide ongoing services. This process has seen enthusiastic commitment from highly credentialed providers in the range of key activities required by the business. Best practice contractual arrangements have been developed to align UED's objectives with those of its contractors, and to drive highly competitive bids during the tender process.
- The new business model will see these best of breed contractors implement new, best-practice systems and processes, and so deliver a more efficient model than currently exists. The business transformation project will 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.
- It is noted that under the present contract structure, the present service provider (JAM) has a right to match the winning bidder that is identified through the competitive tender process. It is uncertain whether JAM will match the winning bid or not, but if they do, they must 'back themselves' to match the efficiencies of the winning bidder's price.
- UED's evaluation of the competitive bids it has received indicates that the total expenditure profile will deliver long term, sustainable value to customers.

3.1 Background

UED's 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's current business model has provided an important evolutionary step in the company's pursuit of its business objectives. In particular, the current business model has:

- enabled UED to build on the significant cost efficiencies achieved in the reform of the Victorian electricity and gas sectors at the time of privatisation;
- allowed UED to lock-in low costs in 2003 at a time when cost pressures were expected to lead to future increases. In fact, JAM's reported costs for 2008 indicate that UED achieved an excellent fixed price arrangement for the current regulatory period;
- resulted in very substantial cost savings for UED's customers, especially compared to distributors in other States where costs have drifted upwards, in some cases significantly so; and
- provided invaluable lessons on how the existing business model can be improved, without compromising service performance or cost efficiency.

The circumstances and nature of the OSA were the subject of considerable debate in the ESC's 2005 Electricity Distribution Price Review, and again in the ESC's Gas Access Arrangement Review in 2007 with respect to Multinet. It is not necessary or relevant to revisit those debates in this submission, except to note that there were a number of aspects of the OSA that were of concern to the ESC, including related party issues; the absence of tendering of the terms and conditions of the OSA; and lack of transparency in the reported costs of AAM (JAM's predecessor).

Issues relating to the lack of transparency in AAM's reported costs were also of concern to UED. In 2009, these concerns culminated in UED successfully taking legal action against AAM. As a result of this action, JAM is now required to provide cost information to UED to enable UED to meet information disclosure obligations to the regulator. UED has been conscious of the need to ensure that sound governance and reporting arrangements are firmly embedded in UED's future contractual arrangements.

Whilst the existing outsourcing arrangements have enabled UED to deliver distribution services at lower prices than its peers (see earlier benchmarking data), the low cost of service provision under the existing OSA has raised governance and risk management issues for UED. In particular, although 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.

Therefore, notwithstanding the substantial cost efficiencies obtained through the current outsourcing arrangements, UED has concluded that the OSA arrangements with AAM should no longer 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 has therefore developed a revised business model to consolidate and build on the efficiencies achieved to date, but also to address some of the operational shortcomings with the OSA that have now become apparent. UED has provided to the AER, on a confidential basis, a copy of a Board paper dated 14 April 2009 (presented at the 24 April 2004 Board meeting), which contains further detailed information regarding UED's preferred business model, and two further Board papers charting UED's progress in bringing its preferred business model to fruition.

3.2 UED's future business model

UED's future business model builds on the operational efficiencies that have been achieved to date. It is neither necessary nor appropriate to build a fresh business model that has no regard to the many benefits that have been achieved through extensive outsourcing. The UED Board has therefore concluded that while there is scope for a number of activities to be conducted within the business, the company remains committed to a flexible and innovative outsourced model.

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 optimal design of contractual terms and conditions.

With AT Kearney's assistance, UED's Board has concluded that its preferred business model should engage one or more 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 best of breed contractors, UED obtains significant benefits in terms of cost and performance compared to the current outsourcing model. In addition to the benefits of engaging best of breed contractors, UED's preferred business model has been designed to achieve the following objectives:

- provide the business with strengthened and increased internal management resources[17], and so provide UED with greater strategic management capability;
- internalise the asset management function, thereby further strengthening the business' strategic capability in this critical core area;
- ensure high levels of transparency and robust governance arrangements in all contracts entered into by UED for the procurement of business inputs;
- enable UED to evolve to the adoption of best-practice forms of contract, principally based on a collaborative contracting model;

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[17] References to internal resources include employees engages directly by UED, by UEDH, or by PIES. PIES is a management vehicle that operates to gain the management synergies between UED and Multinet. Currently UED senior management are employed by PIES and via that vehicle, manage the UED and Multinet businesses under one management structure. The PIES arrangements are structured so that PIES charges UED its share of the PIES costs, and PIES makes no profit or loss. Any reference to 'in-house' or 'in-sourced' in this document, in respect of UED management functions, is intended to cover the option of management being engaged through PIES.

- reduce UED's reliance on any one contractor, by moving towards an outsourcing model that includes multiple contracts and multiple service providers;

- adopt pricing and incentive structures in the contractual arrangements that are best practice and appropriate having regard to the objectives of providing efficient cost and service outcomes for UED and its customers in the short, medium and long term;

- decrease the risk of inefficient or sub-optimal service performance through a commercial framework that is free of mechanisms that provide incentives to service providers to engage in under or over-servicing;

- decrease financial, regulatory and service performance risks that can arise through a misalignment of asset owner and service provider objectives, by establishing an alliancing style contract based on jointly agreed objectives and budgets, and a shared focus on how to achieve the best outcomes; and

- improve the business' ability to adapt to changes expected to impact electricity distribution businesses in the coming years with a business structure that has greater strategic management capability and flexibility.

In light of the above objectives, and based on the experience and recommendations of AT Kearney, UED concluded that it should split its network into regions with separate Network Operations Services suppliers for each region. In reaching this decision, UED consulted industry to better understand the implications of such a split on network performance, efficiency and customer service.

UED operated a two region contractor structure in the period 2001 to 2003. In 2001 we made a specific decision to move to this structure to best manage risk and maintain ongoing price tension between contractors. Whilst in 2003 we evolved to a single contractor model, a comparison of the two approaches leads the business to conclude that the two region model is the better.

In 1999 Vector, a leading provider of electricity distribution in New Zealand servicing over 25 per cent of the country's electricity connections, made the decision to split its Auckland network into three regions and appoint a separate Network Operations service provider for each region – Northpower, Energex and Transfield. Chosen by competitive tender, each zone contractor entered a performance based contract, and competitive tension between the three regional operators led not only to a decrease in operating costs through a range of efficiencies, but an improvement in service performance across the entire network.

In UED's case, a two region model would expose the majority of operational and capital expenditure to continuous competitive pressure between best-of-breed service providers, while ensuring that each network is sufficiently large to avoid scale inefficiencies that may arise with smaller packages of work. UED believes that the operational challenges in managing the two region model will be more than offset by the benefits of continuous competition between the service providers. 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.

Although UED's Board wishes to retain an outsourced business model, UED embarked on a systematic assessment to determine which services should be provided within the business. In this regard, UED addressed two questions:

- Which services should be outsourced?
- What is the most beneficial outsourcing model for the business?

In order to answer these questions, UED applied the following analytical approach:

- Services were defined and analysed: This enabled the determination of whether particular services are standalone or integrated or bundled with other services to form a package.
- Interdependencies were analysed: The nature and complexity of the interdependencies between services that are provided internally, as well as those that are outsourced was examined.
- The strategic direction for the business was considered: This overlay ensured that detailed analysis and decision-making took place with a clear understanding of the strategic direction and the desired end state for the business' services in the context of wider initiatives.

For each service or function within the business, a decision framework was applied that incorporated the following:

- Strategic assessment: This assessment considered whether the service or function has high strategic importance for the business in that it controls value driving decisions, or whether it contains any unique or proprietary assets.
- Operational Assessment: This assessment considered whether the business has superior operational capability for the provision of the service or function.
- Financial Assessment: This assessment considered whether the business has a significant cost advantage over the market. It also examined the question of whether there is an efficient, contestable market for the provision of the service.
- Internal Improvement Assessment: This assessment considered whether the business can achieve a significant cost advantage over the market.

The output of these assessments provided an initial indication as to whether or not UED should 'make' or 'buy' each service required by the business. An overview of this make/buy decision framework is provided in Figure 3-1below.

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

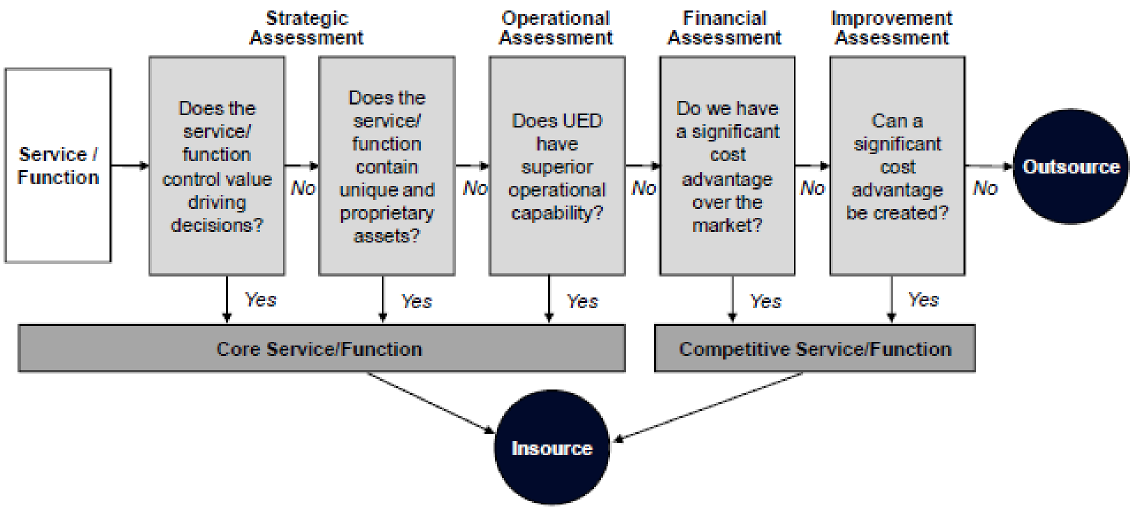


Table 3-1and Table 3-2 summarise the outcomes of this 'make' or 'buy' evaluation process.

Table 3-1: Outsourced service packages from July 2011

Business Area	Service Package
Network Management Services	• Network Operations Services • Network Control Centre Services
Customer & Market Management Services	• Customer Contact Centre Services • AMI Rollout Program Management Office
IT	• Infrastructure Management (including Desktop Management / RTS Infrastructure) • Applications Management • IT Project Services • IT Management Services

Table 3-2: UED's internal functions from July 2011

Business Area	Internal Functions
IT Services	• IT Strategy and Architecture • IT Project Portfolio Management • IT Service Delivery Management
Corporate Services	• Finance ; HR and Administration • Regulatory Services • Legal and Key Contract Management • Business Development

Business Area	Internal Functions
Network Management	• Asset Management • Development of Asset Management Plans and work programs • Network development planning • Network information management (strategy and analysis) • Maintenance planning • Communications planning • Compliance strategy in all areas • Service Delivery Management • Management of interface with Service Providers for network services • Monitoring of Service Providers' operational compliance in all areas • Performance management
Customer and Market Management	• Key Customer and Market Relationship Management • Business Development • AMI Telecommunications Management • AIMRO contracts management • Key Customer Management (key end user customers) • Stakeholder Management • Market Services Strategy • Excluded Services • Customer Satisfaction Survey

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. This review assisted UED in better understanding recent trends and challenges in relation to outsourcing. The review confirmed that UED's evaluation of the 'make' or buy' decision as shown in Table 3-1 and Table 3-2 is appropriate. Attached as an appendix is a paper written by AT Kearney regarding the Optimal Business Model.

3.3 Best practice contractual arrangements

An important objective for the preferred business model is to ensure that best practice contractual and governance arrangements are adopted. In broad terms, UED – like any other business, regardless of whether there is economic regulation in place - must ensure that its objectives and those of its service providers are closely aligned. Given the form of economic regulation that applies to UED, the company must also ensure that all regulatory requirements in terms of transparency and reporting are satisfied.

In this context it is helpful to consider the incentives created by simple contractual models:

- A fixed price model creates strong incentives for efficiency, but the service provider's profits tend to be maximised when service levels are close to the minimum acceptable. If the services involve a relatively high number of future unknowns, transferring these risks to the service provider can lead to inefficient pricing of risks. Hence a fixed price model is only appropriate when the product or service can be completely specified at the outset, where quality is relatively easy to ensure, and future unknowns are relatively low.

- A cost-plus model provides appropriate incentives in relation to service quality, and is more likely to result in satisfactory outcomes if scope requirements change over time. Such a model will also reduce the service provider's requirement to recover a risk premium. However a cost-plus model provides weak incentives for efficiency. This model is only appropriate when quality and service are more important than cost, and the client believes it can minimise the adverse effects of the incentive properties of this model by other means, for example through extensive cost monitoring.

- A simple hybrid of a fixed base price and (cost-plus) schedule of rates for changes is often used, particularly when there is a need for both efficiency and flexibility. However, the competitive process will tend only to minimise base price, with scope changes priced on a cost-plus basis, which may be non-competitive.

All of these simple models suffer from a common problem: they create incentives for the service provider which are misaligned with the customer's objectives – i.e. the service provider profits from behaviours which are not in the customer's interests. Aligning the parties' objectives requires a more sophisticated contractual approach drawing on best practice in utilities and other industries.

AT Kearney has provided advice to UED on the design of the future service contract so that the objectives of the client and the service provider(s) are strongly aligned, and both parties 'win' or 'lose' together, rather than an environment where one party wins or loses 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.

3.4 Retendering process and outcomes

UED recognised that the success of Project 7/11 depends on the tender process being highly competitive so that the best possible price can be obtained from alternative service providers. UED's approach to the tendering process has focussed on minimising entry barriers to potential respondents; avoiding inappropriate risk transfer (with associated inefficient pricing); and creating the foundations for a positive relationship with the future 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 probity protocols throughout the process, which were based on the following principles:

- integrity and impartiality – treating bids and potential bidders in a fair and even handed way;

- effective competition – aiming to maximise the value for money outcome;

- consistency and transparency of process – objective evaluation against identified criteria;
- security and confidentiality; and
- identification and resolution of conflicts of interest.

In December 2008, UED commenced a three phased process to identify Turnkey Service Provider(s) to appoint to deliver the services being tendered, and to help UED transition to its new business model. The three stages of this tendering process were:

- Expression of Interest (EOI);
- Request for Proposals (RFP); and
- Target Cost Establishment (TCE).

The purpose of the EOI stage was to identify parties that have the capacity, capability and expertise to act in one or more of the following roles:

- lead contractor, delivering all services being tendered by self-performing some and subcontracting other services;
- one of several lead contractors which together deliver all of the services (either by forming a consortium or entering separate contracts with UED); and
- specialist subcontractor who supports a lead contractor.

The EOI enabled UED to inform the market of the key characteristics of its preferred business model, and in particular, the opportunities available to outsourced service providers under that model. The EOI was also designed to identify potential service provider consortia.

The EOI process was used to assess respondents in terms of:

- financial stability and capability as evidenced by audited financial statements and commercial credit checks;
- corporate experience and capability in performing services similar to the service elements being tendered;
- corporate experience and capability in collaborative contracts, partnering, alliancing, and business transformation;
- corporate experience and capability in management of safety, environmental, and stakeholder issues; and
- demonstrated performance in the above aspects as evidenced by reference sites and referee checks.

A total of 61 potential suppliers submitted responses to the EOI, of which a total of 36 respondents were assessed as being "Prequalified Respondents" and capable of providing some or all of the services being tendered.

In early April 2009, UED invited the seven EOI respondents short-listed as potential Turnkey Service Providers to submit written proposals in response to the requirements set out in its *Utility Operations and Management Services* Request for Proposal. The RFP and

RFP Addendum (released later in April) set out the terms and conditions (including compensation mechanisms) proposed for both the TCE and service delivery stages.

The RFP stage was designed to short-list respondents that demonstrated the greatest ability to deliver the required services and work with the business to achieve the objectives for each service package. Respondents were asked to prepare a qualitative capability submission and quantitative pricing submission which were designed to assess the following:

- capability to provide the requested services;
- capability to deliver on transformation/transition for UED's business;
- ability to deliver an effective integrated outcome for UED through the proposed consortium arrangements;
- ability to work with UED and to enable UED to fulfil its regulatory obligations;
- willingness and ability to execute a successful TCE Stage;
- expected costs for UED; and
- suitability and capacity to partner with UED.

After assessing each of the submissions in response to the RFP, each of the consortia were invited to attend separate workshops to receive feedback on their submissions. Each consortium was then provided with the opportunity to revise submissions based on this feedback and to re-submit those submissions for final evaluation. Following further workshops, two consortia were selected to proceed to the TCE stage.

The TCE stage was focused on developing:

- a detailed proposal to UED for the delivery of the services outlined within the RFP;
- a proposal addressing matters relating to the transformation of UED's business to the desired end-state as described in section 3.2; and
- a five-year total cost target and margin, with agreed financial and non-financial incentive arrangements.

The TCE stage included the following elements:

- a Service Delivery Plan for the provision of the tendered services;
- a Mobilisation Plan for mobilisation of the resource by the service provider ahead of 1 July 2011 and, if JAM does not exercise its right to match the transfer of the tendered services from JAM;
- a Transformation Plan to assist UED in transforming its business to its desired end-state operating model;
- five-year financial targets for the delivery of the services; and
- negotiation of the terms and conditions to apply under the new outsourcing services agreement titled "Operational and Management Services Agreement".

Following the completion of the tender process, UED management with the assistance of AT Kearney evaluated the competing bids. A recommendation to select a bidder was subsequently made to and accepted by the UED Board. A copy of the relevant Board paper has been provided to the AER on a confidential basis. Section 3.5 below explains why UED is confident that the selected bidder, in combination with the business' resources, will deliver the most efficient outcome for UED and its customers.

The commitment that the bidders have show to the process, including incurring significant bid costs, is evidence of the competitiveness of the process.

3.5 Tender evaluation and transformation costs

UED's evaluation of the tender outcomes has validated the Board's decision to embark on a business transformation process. Business transformation processes typically require additional upfront costs in the short-term in order to deliver longer term cost reductions and service improvements. UED's business transformation is no different. UED has identified the need for significant changes in existing business systems and processes in order to deliver better outcomes in terms of:

- cost and service performance;
- risk management; and
- improved governance, including cost transparency and reporting.

UED has 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 best of breed model.

The operating and capital expenditure forecasts in this Regulatory Proposal reflect the market tested bid provided by the lowest cost consortium of contractors. Further detailed information on UED's forecast operating and capital expenditure is provided in Chapters 0 and 0 of this Regulatory Proposal. Figure 3-2 and Figure 3-3 below show comparisons of 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

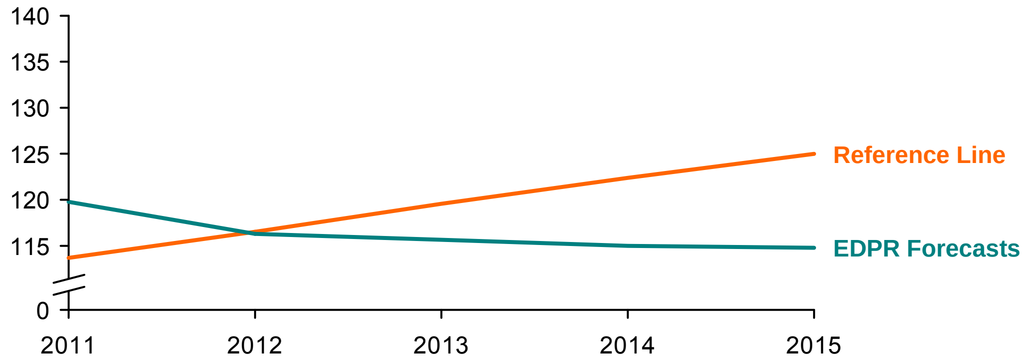
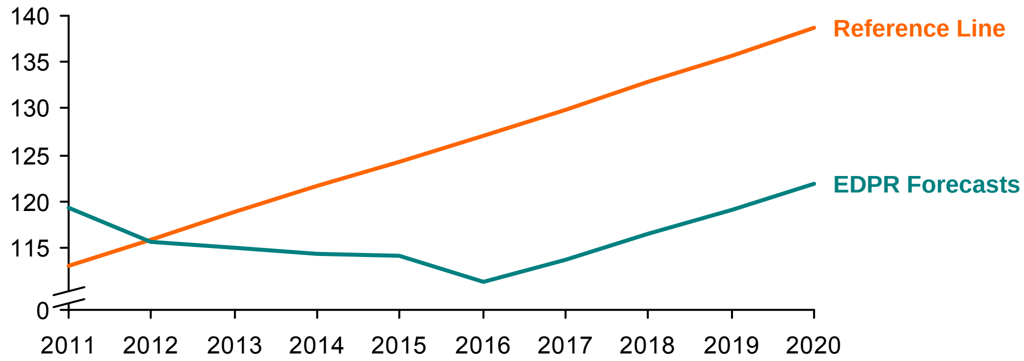


Figure 3-3: UED's 10 year comparisons (OPEX) – DUOS opex only



Note: The reference line in figure 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[18].

Table 3-3 below shows the total operating expenditure forecasts under the proposed business model and the reference point over five and 10 year periods.

Table 3-3: Comparison of five and 10 year operating expenditure (DUOS opex only) forecasts - UED preferred business model versus reference line

	5-Year Aggregate Cost $M	5-Year NPV $M	10-Year Aggregate Cost $M	10-Year NPV $M
Current Business Model Reference Line	597.3	501.8	1,264.9	921.0

[18] **An appendix is attached that details the assumptions supporting the calculation of the reference point.**

	5-Year Aggregate Cost $M	5-Year NPV $M	10-Year Aggregate Cost $M	10-Year NPV $M
UED's Preferred Business Model	581.9	490.8	1,167.8	858.7
Savings under UED's preferred business model	**15.4**	**11.0**	**97.1**	**62.3**

Amounts shown in real 2010 terms.

Figure 3-4 below shows that the payback period in relation to operating expenditure under UED's preferred business model (compared to the reference line) is between two and three years.

Figure 3-4: Cumulative savings ($m) on operating expenditure (DUOS opex only) under UED's proposed business mode compared to reference point

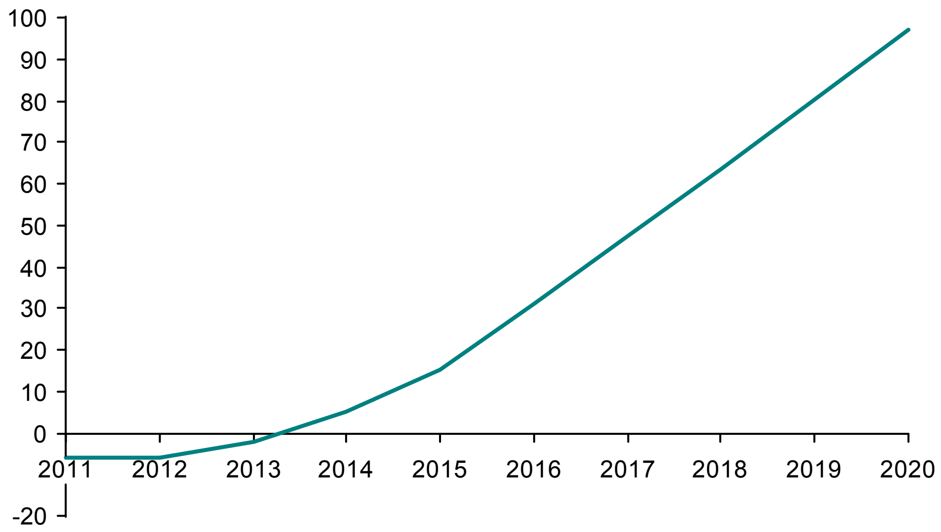


Table 3-4 below shows the total expenditure forecasts under the proposed business model and the reference line over a 5 period.

Table 3-4: Comparison of five year total expenditure (DUOS opex and capex) forecasts ($m) - UED preferred business model versus reference line

	5-Year Aggregate Cost $M	5-Year NPV $M
Current Business Model Reference Line	1,632.5	1,376.5
UED's Preferred Business Model	1,529.4	1,294.7
Savings under UED's preferred business model	**103.1**	**81.8**

Amounts shown in real 2010 terms.

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 clearly lower than for the reference case (i.e. a projection of current costs). The NPV over five years is clearly beneficial relative to the base case, and the transformation costs have a very short payback period.

Importantly, the detail above validates, with quantitative analysis, the key "in principle' Board decisions regarding the preferred business model. As noted in Chapter 2 of this Regulatory Proposal, benchmarking UED against other Australian distribution businesses shows UED's current business model to be efficient in comparison to those other distribution businesses. Furthermore, benchmarking shows a strong correlation between the level of outsourcing and efficiency – those companies that have engaged in aggressive outsourcing have achieved significant efficiency improvements, whilst those companies that have continued with services provided within the business have been unable to deliver comparable efficiencies.

The existing OSA includes a provision under which the existing service provider (JAM) can match the winning bid. It is unknown at this stage whether JAM will exercise this right. In the event that JAM does match, they will be matching a contract to restructure the business, and not just operate the network on a status-quo basis. JAM will therefore be held to match the terms of the winning bid, including the transformation program that will deliver the operational efficiencies identified by the tender process.

UED is currently in dispute with JAM in relation to its right to match. Refer section 5.4.3 for further details.

UED is also mindful of the regulatory issues that may arise in relation to outsourcing decisions. In previous regulatory processes in Victoria, the ESC has examined in detail two alternative business cases:

- service provision within the business, where no profit margin is earned in relation to the services provided; and
- outsourced service provision, which may be more flexible, innovative and lower cost, but the service provider expects to earn a profit margin.

From a purely commercial perspective, the primary objective is to deliver the most efficient outcome in terms of price, service performance and risk. It is common commercial practice to pay a profit margin to an outsourced service provider, providing that the overall outcome is beneficial. In effect, a commercial decision must compare feasible alternatives, and not hypothetical or impractical ones, at an aggregate level. For example, it is not possible to mix and match components from alternative options to avoid certain cost items, such as profit margins, restructuring or establishment costs.

UED notes that regulatory concerns can arise where outsourced service providers are related to the licensed service provider. UED has therefore embarked on a competitive tender process, supported by a probity plan and audit to ensure that these regulatory concerns are addressed. UED has already provided copies of the probity auditor's reports to the AER on a confidential basis.

Having established a competitive framework for selecting the service provider, UED expects that the commercial and regulatory imperatives will be aligned. In particular, the focus from a commercial and regulatory perspective should be on the delivery of the most efficient services to our customers, in terms of price, quality and risk.

As noted above, the outcome of the tender process is reflected in UED's expenditure plans and forecasts that are described in this Regulatory Proposal. As such, UED is confident that its expenditure forecasts reflect a comprehensive, accurate and up-to-date assessment of the efficient costs of achieving the operating and capital expenditure objectives, in accordance with clauses 6.5.6(c)(1) and 6.5.7(c)(1) of the Rules. Further details of UED's forecasting methodology are provided in Chapters 0 and 0 of this Regulatory Proposal.

4. Planning for future demand and service performance

Key messages

- The Rules require UED's Regulatory Proposal to include expenditure forecasts that reasonably reflect the demand for its services and also enable the company to maintain the reliability, safety and security of the distribution system, and comply with all regulatory obligations. In the period from 1997 to 2003, UED made substantial improvements in network reliability but it will be hard to maintain present levels due to the effects of climate change.

- UED's asset management plan addresses these Rules requirements through 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's capital budgeting and asset management activities are focused on delivering efficient asset maintenance, efficient investment decisions and efficient project execution.

- 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 typical summer 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 significant change in the regulatory obligations relating to safety management, and additional costs will be incurred by UED as a result. These costs are either included in UED's expenditure forecasts or will be recovered via pass-through arrangements.

- Climate change is already affecting UED's network performance and the impacts of climate change are expected to intensify further in the future. 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.

- UED expenditure plans will enable the company to meet its proposed service targets in the context of the effects of climate change, which include exposure to increased frequency and intensity of storms, and an increase in the number and severity of hot days.

- Targeting service performance against the backdrop of more volatile weather extremes is subject to error and risk. In particular, as noted above climate change exposes UED to increased frequency and intensity of storms, and an increase in the number and severity of hot days. Nevertheless, UED's expenditure plans are designed to meet its proposed service targets.

- In the medium term, UED's business transformation should assist UED in reversing the recent trend decline in network reliability.

4.1 Regulatory requirements and chapter structure

Clauses 6.5.6(a) and 6.5.7(a) of the Rules set out the operating and capital expenditure objectives (respectively), which effectively provide the foundation for the expenditure forecasts presented in a Regulatory Proposal. Specifically, the expenditure objectives are:

- meet or manage the expected demand for standard control services over the regulatory period;
- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- maintain the quality, reliability and security of supply of standard control services;
- maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In effect, the operating and capital expenditure objectives require UED to ensure that its expenditure forecasts properly reflect:

- the expected demand for (or "volume" of) the services to be delivered over the forthcoming regulatory period; and
- the standard (or "quality") of the services to be delivered, which includes compliance with mandatory obligations.

The Rules require the AER to be satisfied that the expenditure forecasts meet certain criteria. In particular, the AER must be satisfied that the total of the forecast expenditure reasonably reflects:

- the efficient costs of achieving the expenditure objectives; and
- the costs that a prudent operator in UED's circumstances would require to achieve the expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the expenditure objectives[19].

In assessing UED's expenditure forecasts against these criteria, the AER must consider a number of expenditure factors[20] in deciding whether the forecast expenditure reasonably reflects the efficient costs of achieving the expenditure objectives. These expenditure factors include, among other things:

- the relative prices of operating and capital inputs;

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[19] **For full details of the operating and capital expenditure criteria, please refer to clauses 6.5.6(c) and 6.5.7(c).**

[20] **For full details of the operating and capital expenditure factors, please refer to clauses 6.5.6(e) and 6.5.7(e).**

- the substitution possibilities between operating and capital expenditure; and
- the extent to which non-network alternatives have been considered and adopted where it is efficient to do so.

Clauses S6.1.1(3) and (4), and S6.1.2(3) and (5) of the Rules also require UED to provide information on the key variables and assumptions that underpin UED's capital and operating expenditure forecasts.

UED's asset management plan substantially addresses all of the above Rules requirements in detail through a series of carefully developed plans that are focused on particular asset types and risk management issues. It is useful, therefore to provide a broad overview of UED's asset management plan in this Chapter before setting out the company's expenditure plans and forecast in Chapter 5 and 6.

The remainder of this Chapter is structured as follows:

- Section 4.2 explains the content and scope of UED's asset management plan.
- Section 4.3 discusses UED's approach to meeting expected demand for services, especially in relation to network connections and demand growth, in accordance clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the Rules.
- Section 4.4 provides commentary on UED's approach to service performance and compliance, in accordance with clauses 6.5.6(a)(2),(3),(4) and 6.5.7(a)(2),(3),(4) of the Rules.
- Section 4.5 explains that climate change presents particular challenges and costs for UED and its customers in future.

4.2 UED's asset management plan

The primary objective of an asset management plan is to effectively manage the life cycle of the distribution network as a whole and of each asset class that comprises the network in the light of changes in the constraints that are faced by the business throughout that life cycle. UED's asset management plan is focused on achieving the following long term, overarching objectives:

- to strive for reliability, safety and customer service to ensure a high reputation in the minds of the community, regulators and key stakeholders; and
- to maintain and develop the network to at least maintain and potentially enhance, the overall asset condition.

UED has thoroughly revised its 2009-2016 asset management plan so that it:

- satisfies the standard set by the British Standard Institute (PAS 55);
- 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 commissioned AECOM to undertake an independent review of the asset management plan. A copy of AECOM's report is provided as an appendix to this regulatory proposal. AECOM found that:

- UED's Asset Management Plan addresses the key requirements for a prudent operation of an Electricity Distribution Network. It considers:
  - Levels of service required
  - Demand growth
  - Asset management and asset life cycle
  - The impact of climate change
  - The impact of new technologies such as smart meters and micro-generation.
- The AMP also considers environmental, power quality, bushfire mitigation and safety management.
- Overall the AMP is sound and comprehensive and forms the basis for development of operational and capital expenditure programs. The plan identifies ongoing increasing levels of spending in response to load growth, the needs of an aging network and the impact of weather related events.

UED's asset management plan is an evolving document, which is subject to periodic review and updating. It comprises 12 individual components, each of which is focused on achieving a particular set of objectives and deliverables that are critical to the achievement of the overall asset management objectives. UED's 2009-2016 asset management plan comprises the following 12 individual components:

- Future Demand Plan;
- Life Cycle Management Plan;
- Advanced Metering Infrastructure Plan;
- Smart Networks Plan;
- Climate Change Plan;
- Environmental Plan;
- Network Safety Plan and Risk;
- Other Network Risks;
- Bushfire Mitigation;
- Power Quality Plan;
- Monitoring and Improvement Program; and
- Asset Management Information Systems.

These documents constitute the planning documents referred to in the RIN, and contain detailed analysis that supports the expenditure forecasts presented in Chapters 0 and 0 of this submission. The asset management plan also provides detailed supporting information and analysis required to substantiate the expenditure forecasts (as required by clauses S6.1.1(3) and (4), and S6.1.2(3) and (5) of the Rules) including:

- legislative requirements and planning standards;
- growth forecasts, including maximum demand, energy and customer numbers;
- network reliability; causes of network faults; reliability and power quality benchmarking; and target levels of reliability;
- network asset utilisation and losses;
- impact of climate change on network performance and other network risks;
- the generation outlook, including future developments in embedded generation; micro generation; demand management; and energy efficiency; and
- asset condition and projected weighted average remaining life.

UED's asset management planning also ensures that there is an optimal balance of capital and recurrent expenditure, so that maintenance, replacement and augmentation of the electricity distribution network delivers the required level of services at the lowest possible life cycle cost. As noted in section 4.2 above, this objective is consistent with satisfying a number of the Rules requirements and forecasting principles set out in clauses 6.5.6 and 6.5.7.

Electricity distribution is a capital-intensive industry, which requires the application of rigorous and efficient capital budgeting and asset management processes to deliver distribution network services. UED's approach to capital budgeting and asset management recognises the need to ensure efficient asset management and robust investment decisions by:

- producing asset management strategies, plans and budgets that are consistent with stakeholder and regulatory requirements;
- maintaining and reviewing these strategies, plans and budgets as new data becomes available;
- monitoring and reporting against key performance indicators;
- managing and resolving resource allocation issues; and
- ensuring efficient works execution through:
    - efficient construction, maintenance and operation of network assets in accordance with the asset strategies, asset management plan and budget;
    - effective management of programs (such as asset inspections and vegetation management); and
    - effective capturing, management and diagnosis of asset condition and performance data.

It is evident from this overview that UED's asset management plan is focused on delivering efficient service outputs and performance for the benefit of customers and consistent with the Rules requirements. To assist the AER and stakeholders in their review of UED's expenditure plans, UED has provided a copy of its asset management plan as part of its Regulatory Proposal.

4.3 Future demand plan

The Future Demand Plan sets out the plans and associated capital expenditure to ensure forecast new connections and demand growth are met. The Future Demand Plan therefore plays a key role in demonstrating UED's compliance with the expenditure objectives that relate to meeting or managing the expected demand for standard control services. The plan considers reliability of supply within a four-way framework:

- line and component ratings;
- probabilistic assessment of loss of supply;
- customer oriented valuation of reliability; and
- contingency planning.

The projections used in the plan are underpinned by new connection and maximum demand forecasts developed by UED and supported by an independent assessment of load growth undertaken by the National Institute of Economic and Industry Research (NIEIR). The NIEIR index is specifically tailored to predicting load growth on UED's electricity network. This index has proven to be a reliable index for predicting future demand.

The aims of the Future Demand Plan include:

- provide sufficient new capacity to enable customers' growth requirements to be serviced efficiently;
- maximise asset utilisation;
- minimise loss of supply due to overloads;
- minimise damage to plant items due to overloads;
- maintain quality of supply (voltage profile) in accordance with obligations;
- maintain or where economic reduce the level of network losses; and
- communicate an agreed risk management strategy for meeting future demand.

The balancing of these conflicting objectives is dependent on the planning standard adopted, which in turn will reflect the level of risk tolerated. UED 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 is managed through contingency planning.

Traditionally, network solutions have been used to meet increasing load demand however alternative methods can be used that provide a more cost effective and/or environmentally-friendly solution. These are generally referred to as non-network solutions and include, among other things, demand management and local electricity generation. UED currently offers network tariffs that provide incentives to encourage voluntary demand management by customers connected to our network at times of peak demand. The scope for, and development of non-network demand solutions is monitored closely and these solutions are taken into account in UED's future demand plan.

4.4 Service performance and compliance

During the forthcoming regulatory period, UED plans to continue to focus on maintaining the present levels of service, and to deliver further improvements where it is feasible and economic to do so.

UED proposes a package of measures (both capital and operating) over the forthcoming period which will deliver maintained service performance by focusing on the worst performing assets and mitigating against a forecast decline in reliability due to climate change effects, and by aiming to reduce interruptions to supply. These programs will maintain the reliability, safety and security of the distribution system.

A full list of the programs is contained in UED's asset management plan and supporting life cycle asset management plans. In summary, however, UED's efforts in the forthcoming regulatory period will include:

- continuing the program of pole fire risk mitigation;
- monitoring and managing distribution load demand to prepare for extreme temperature events;
- vigilance in regular asset inspection and vegetation management to ensure asset integrity;
- analysing root causes of faults and reducing the number of outages on rogue feeders and in poorly-performing areas of the network;
- implementing policy and guidelines to address the rising trend of HV conductor clashing;
- installing additional Automatic Circuit Reclosers and Remote Controlled Gas Switches to reduce the impact of faults;
- installing additional overhead line fault indicators;
- trialling the installation of Ground Fault Neutralisers to determine level of network reliability performance that can be gained;
- developing remote control and monitoring of indoor and kiosk substation switchgear; and
- developing remotely-monitored fault indicators.

As previously noted, UED's asset management plan is focused on compliance with the relevant legislation, codes, and regulations administered by the Energy Safety Victoria

(ESV), and other regulatory bodies such as WorkSafe, the Environmental Protection Agency and VicRoads.

The main regulations that govern safety are the Electricity Safety (Installation) Regulations, the Electricity Safety (Management) Regulations, the Bushfire Mitigation Code and the industry documents, the 'Blue Book' and the 'Green Book'. These regulations cover such things as design clearances of live conductors to people and structures, requirements applying to construction industry personnel regarding temporary minimum clearances i.e. 'No Go Zone' publications, safe working requirements for people working on the network, and requirements relating to regular inspection and testing of the assets.

The Electricity Safety Act makes provisions for the safety of electricity supply in Victoria. UED is required to comply with the provisions of the Act and subordinate regulations and standards relating to the design, construction, operation and maintenance of a distribution network and a number of underpinning regulations will no longer apply. 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.

Whilst UED supports the new approach to safety management that will be introduced under the new Act, the additional costs in compliance must be reflected in the company's expenditure plans and costs to customers. UED is confident that its asset management plans and associated expenditure forecasts properly reflect the appropriate initiatives and work programs required to achieve compliance with its service obligations, in accordance with the expenditure objectives in clauses 6.5.6(a)(2), (3) and (4), and 6.5.7(a)(2), (3) and (4) of the Rules.

It is also noted that UED's asset management plan contains detailed information on the key variables and assumptions that underpin UED's operating and capital expenditure forecasts in accordance with Clauses S6.1.1(3) and (4) and S6.1.2(3) and (5) of the Rules. Further discussion of these Rules requirements is provided in Chapters 0 and 0 of this submission.

4.5 Climate change

Climate change is already impacting directly on the performance of UED's distribution network. This observation is supported by AECOM's report on climate change which is attached as an appendix. The impact of climate change on UED's network is pervasive; it is directly affecting the reliability of the distribution services we provide to our customers and it also affects UED's future operating and capital expenditure. In essence, adverse climate change means worsening network performance and more costly network services.

It is widely understood that climate change is a global phenomenon that is beyond the direct control of individual citizens or companies. On the other hand, it is also recognised that there is a shared responsibility to consider climate change in our future decision-making. As a responsible corporate citizen, UED is taking account of climate change in its asset management plans so that customers continue to obtain the optimal balance of network reliability and cost.

In particular, 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. 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 CMAR. 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 have been taken into account in the preparation of UED's Regulatory Proposal, particularly in relation to capital expenditure forecasts (Chapter 6) and service performance targets (Chapter 16) .

5. Forecast Operating Expenditure

Key messages

- UED's operating expenditure forecasts have been developed in accordance with the requirements of the Rules and the RIN.
- UED's operating expenditure forecasts reflect the outcome of a rigorous, competitive tender process to replace the existing OSA, the current term of which expires in July 2011.
- The business transformation and tendering project ("Project 7/11") has been developed and conducted with the assistance of AT Kearney and the tender process is subject to a probity audit by Dench McClean Carlson.
- Services currently provided by PIES and DUET will continue to be provided in the forthcoming regulatory period.
- KPMG has reviewed and endorsed UED's forecasting methodology, providing 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.
- Benchmarking demonstrates that UED is already an efficient service provider. The business transformation process will incur additional costs to establish new business processes and systems, which will provide significant savings within five years.
- UED's tender evaluation process indicates that JAM will need to make significant efficiency improvements and transform its business processes and systems if it is to match the winning bid. The operating expenditure forecasts presented in this Chapter are insensitive to whether JAM decision as to whether or not it matches the winning bid.

5.1 Regulatory requirements and chapter structure

Clause 6.5.6(a) of the Rules requires UED to present an operating expenditure forecast for the forthcoming regulatory control period that will achieve each of the following objectives:

- meet the expected demand for standard control services over that period;
- comply with all applicable regulatory obligations associated with the provision of standard control services;
- maintain the quality, reliability and security of supply of standard control services; and
- maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In addition, clauses 6.5.6(b)(1) and (2) also require UED to:

- comply with the requirements of the AER's Regulatory Information Notice (RIN); and
- only include expenditure that is properly attributable to standard control services in accordance with the principles and policies set out in UED's cost allocation methodology.

Clause S6.1.2 specifies other information that must be provided by UED to explain and substantiate the forecast of required operating expenditure including, amongst other things, an appropriate categorisation of the operating cost forecast, the method used for developing the forecast and a certification of the reasonableness of the key assumptions by UED's directors.

Under clause 6.5.6(c) of the Rules, the AER must accept the forecast of required operating expenditure that is included in the revenue proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects the following operating expenditure criteria:

- the efficient costs of achieving the operating expenditure objectives;
- the costs that a prudent operator in the circumstances of the relevant distribution company 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.

UED's forecast operating expenditure for the forthcoming regulatory period has been developed to meet the above objectives and regulatory requirements. In addition, this Chapter provides other information that, whilst not required by the Rules, is intended to assist the AER in its assessment of UED's operating expenditure forecasts.

The remainder of this chapter is structured as follows:

- Section 5.2 describes UED's operating expenditure categories in accordance with the RIN, and provides an overview of the operating expenditure forecasts by category for each year of the forthcoming regulatory period;
- Section 5.3 explains UED's operating expenditure forecasting method;
- Section 5.4 describes the key variables and assumptions that underpin UED's operating expenditure forecasts;
- Section 5.5 provides a detailed breakdown of UED's operating expenditure forecasts by category; and
- Section 5.6 benchmarks UED's operating expenditure forecasts to demonstrate that the Rules requirements in relation to cost efficiency are satisfied. This section also provides a comparison of UED's historic and forecast operating expenditure, detailing the reasons for material changes between historic and forecast operating expenditure.

5.2 Operating expenditure categories and overview of expenditure forecasts

Clause S6.1.2 of the Rules sets out the minimum information requirements that a building block proposal must contain in relation to operating expenditure. In relation to the choice of operating expenditure categories, clause S6.1.2(1) states that a building block proposal must contain a forecast of the required operating expenditure that complies with the requirements of clause 6.5.6 of the Rules and identifies the forecast operating expenditure by reference to well accepted categories such as:

- particular programs; or
- types of operating expenditure (e.g. maintenance, payroll, materials etc), and identifies in respect of each such category:
- to what extent that forecast expenditure is on-costs that are fixed and to what extent it is on-costs that are variable; and
- the categories of distribution services to which that forecast expenditure relates.

In addition to the above Rules requirements, operating expenditure categories for standard control services are defined by the RIN for UED as follows:

(a) network systems operation;

(b) SCADA and network control;

(c) billing and revenue collection;

(d) customer service;

(e) advertising, marketing and promotions;

(f) regulatory costs;

(g) GSL payments;

(h) other network operating costs;

(i) routine maintenance expenditure;

(j) condition based maintenance expenditure;

(k) emergency maintenance expenditure; and

(l) any other category included in the regulatory proposal.

In light of the Rules and RIN requirements noted above, UED has developed its forecast operating expenditure in accordance with the categories shown in Table 5-1 below. UED’s forecasts of operating expenditure for each category for each year of the forthcoming regulatory period are also shown in Table 5-1.

Table 5-1: Categories of forecast operating expenditure and overview of expenditure forecast

	YEAR ENDING 31 DECEMBER					Total
	2011	2012	2013	2014	2015	$M
MAINTENANCE						
Routine	7.2	7.3	7.4	7.4	7.4	36.7
Condition based	11.0	10.5	10.5	10.5	10.5	53.0
Emergency based	6.0	5.8	5.8	5.8	5.8	29.3
Other maintenance	0.0	0.0	0.0	0.0	0.0	0.0
Sub-total maintenance	**24.2**	**23.6**	**23.7**	**23.7**	**23.8**	**119.0**
OTHER FUNCTIONS						
Network operating	32.5	31.7	32.2	32.2	32.3	160.8
SCADA/Network control	5.8	5.9	5.9	5.9	5.9	29.2
Billing & revenue	2.6	1.8	1.8	1.9	1.9	10.0
Customer service	8.1	8.2	8.2	8.2	8.2	40.8
Advertising	1.8	0.6	0.6	0.6	0.6	4.3
Regulatory	2.7	1.8	1.8	2.0	2.3	10.5
Self insurance	3.5	3.5	3.5	3.5	3.5	17.7
Debt raising	1.0	1.1	1.1	1.2	1.2	5.6
Other	41.6	42.0	40.9	40.1	39.2	203.8
Sub-total other functions	**99.6**	**96.6**	**96.0**	**95.5**	**95.2**	**482.9**
Total operating expenditure	**123.8**	**120.2**	**119.7**	**119.2**	**118.9**	**601.8**

Amounts shown in real 2010 terms.

Detailed information that explains the methodology and assumptions applied in the development of these forecasts is set out in the remaining sections of this chapter.

5.3 Overview of UED's forecasting methodology for operating expenditure

Sections 2.2 and 2.3 of this Regulatory Proposal explained that UED has delivered substantial price reductions and service performance improvements since its formation in 1995. Compared to other networks, UED's total expenditure has remained consistently low, whereas other network businesses have allowed their expenditure to drift upwards and, in some cases, quite significantly (see graphs in chapter □). UED's exemplary cost performance is attributed to its outsourced business model which comprises:

- a small, efficient management structure that conducts strategic management and corporate governance activities within the business and by drawing on services provided by its parent entity DUET; and

- a single outsourced contract (the OSA) currently let to JAM (formerly Alinta Asset Management) for all of its direct business operations and a number of corporate and back office functions.

UED's present business model was put in place in 2003, in order to build on the significant efficiency gains that the company had already achieved at that time since its privatisation. In particular, the outsourced business model adopted in 2003 provided a basis for further aggressive cost reduction and efficiency improvement, the positive results of which are described in section 2.2.

There is no doubt that UED's existing operating expenditure is efficient.

Section 3.2 of this Regulatory Proposal explained that UED has now embarked upon a rigorous, competitive tender process to replace the existing OSA, the current term of which expires in July 2011. Section 3.2 explained that the business restructuring and tendering project ("Project 7/11") involves the transformation of UED's business to a more sustainable, transparent business model which seeks to employ best-of-breed service providers through a competitive tendering process.

As also noted in section 3.2, the tendering process undertaken as part of Project 7/11 has been developed and conducted with the assistance of AT Kearney and the tender process is subject to a probity audit by Dench McClean Carlson. Copies of the probity auditor's reports have been provided confidentially to the AER.

Given the robustness of Project 7/11 and the associated tender process, its outcomes form the basis of UED's method for forecasting operating (and capital) expenditure. By taking this approach, UED is able to reflect the latest available information; derived from a process designed to deliver efficient cost outcomes in its expenditure plans. In this regard, the resulting forecasts would best reflect the following operating expenditure criteria that the AER must apply in accordance with clause 6.5.6(c) of the Rules:

> " … 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."

Importantly, Project 7/11 and the competitive tender process has also led to a change in the mix of services that will be provided by the external service provider and those services that will be provided within the business.

It is noted that the tender process can only provide competitive tender costs in relation to outsourced services. UED's methodology for forecasting operating expenditure therefore considers separately expenditure within the business and the costs of outsourced services.

UED understands the importance of designing a forecasting methodology that captures accurately a mix of service provision within the business and through outsourcing, in circumstances where that mix is proposed to change from the existing arrangements. For example, to satisfy the Rules requirements it is necessary to show that each forecast line item is neither omitted nor double-counted in the overall expenditure forecast.

In view of these considerations, UED engaged KPMG to provide an independent assessment of whether the design of UED's forecasting methodology for operating (and capital) expenditure, and the application of that methodology will provide expenditure forecasts for the regulatory control period that:

(a) reasonably reflects:

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

(b) complies with the requirements of the Rules that relate to the preparation of expenditure forecasts, and any relevant regulatory information instrument; and

(c) are properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the Distribution Network Service Provider.

KPMG has provided a report in relation to these matters. That report forms part of this Regulatory Proposal and is provided as an appendix.

In relation to the design of UED's operating (and capital) expenditure forecasting methodology, KPMG's report concludes that:

- UED's methodology is designed to enable the assumptions on which the expenditure forecasts are based to be readily identified;
- UED's methodology enables an assessment of whether the forecast is designed to present expenditure fairly, consistent with those assumptions;
- the models used to calculate the forecasts are designed to undertake calculations that are mathematically and logically consistent with the stated assumptions; and
- UED's methodology is designed to reasonably reflect relevant requirements of the National Electricity Rules.

In relation to the application of UED's methodology, KPMG's report finds that:

- the assumptions of data that form inputs to the forecast's models and calculations, have been:
    - forecast in accordance with the design of UED's methodology; and
    - input to the methodology's models and calculations in accordance with the methodology's design and the data requirements of those models;
- the methodology's calculations of forecast expenditure are mathematically and logically consistent with the stated assumptions; and
- the EDPR expenditure forecasts agree to the expenditure forecast by the methodology.

Accordingly on the basis of these findings KPMG concluded that UED has implemented the forecasting methodology in a way that is consistent with its design, that is to say that it is consistent with providing expenditure forecasts for the regulatory control period that:

(a) reasonably reflect:

(1) the efficient costs of achieving the operating expenditure objectives and capital expenditure objectives; and

(2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives and capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives and capital expenditure objectives;

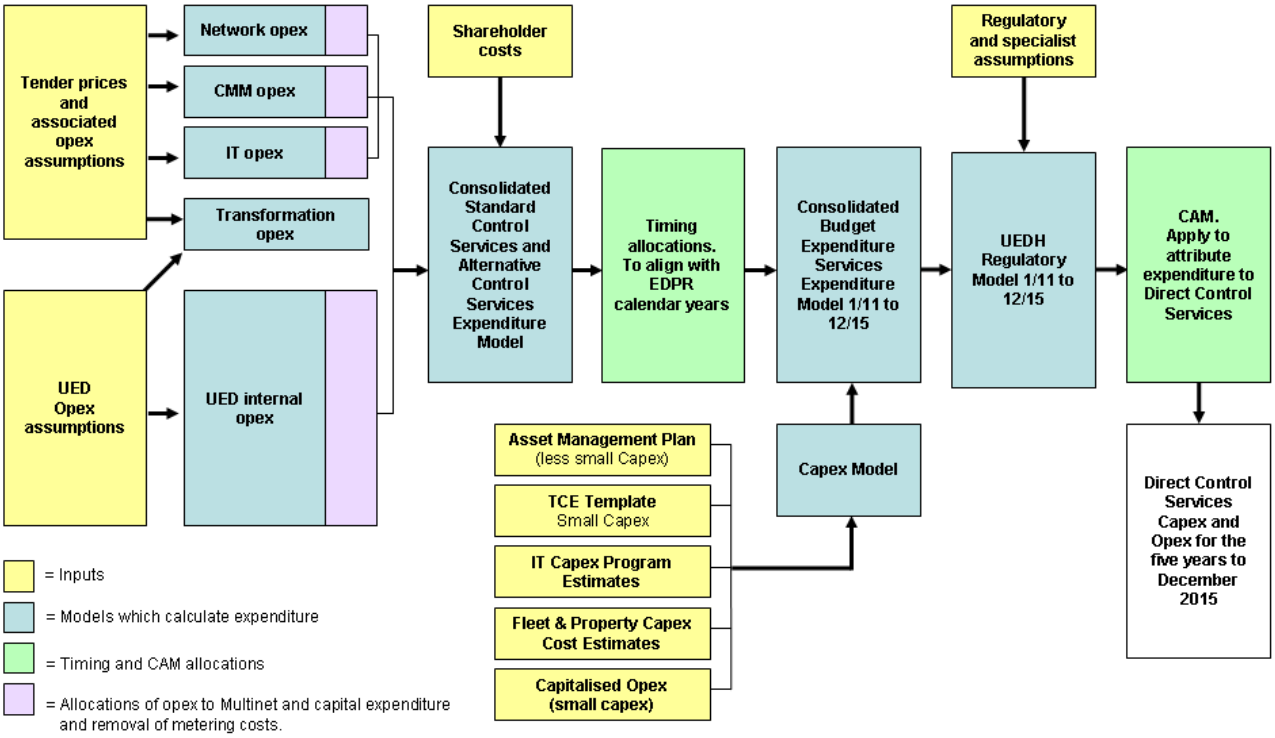
(b) complies with the requirements of the National Electricity Rules that relate to the preparation of expenditure forecasts, and any relevant regulatory information instrument; and

(c) are properly allocated to direct control services in accordance with the principles and policies set out in the Cost Allocation Method for the Distribution Network Service Provider.

The remainder of this section summarises UED's forecasting methodology for operating expenditure. Further details of the forecasting methodology and underlying assumptions are set out in KPMG's independent report, which is provided as an appendix to this Regulatory Proposal.

Figure 5-1 provides a schematic representation of UED's method for forecasting operating expenditure. For completeness, the figure depicts UED's method for forecasting both capital and operating expenditure, although the diagram clearly distinguishes between these two categories of expenditure. Each of the key assumptions that underpin the method is described in section 5.5.

Figure 5-1: UED's method for forecasting operating expenditure



N.B. This diagram shows the architecture of information flows through models used by the Methodology. It does not purport to represent corporate structures or expenditure relationships.

Figure 5-1 shows that UED's forecasting methodology distinguishes between the following four main elements:

1. Operating expenditure associated with services that are procured from outsourced service providers;
2. Operating expenditure associated with services and functions that are undertaken within UED;
3. Operating expenditure associated with services provided by UED's parent (denoted as "shareholder costs in the figure above); and
4. Capital expenditure.

In relation to the first category (operating expenditure on outsourced services), four sub-categories are defined for the purpose of developing the expenditure forecast. These categories reflect the array of services that are listed in Table 3-1 (Outsourced service packages from July 2011) and they are as follows:

(a) Network operations expenditure;

(b) Customer and market management (CMM) services operating expenditure;

(c) Information technology (IT) operating expenditure; and

(d) Transformation operating expenditure.

Transformation operating expenditure relates to the costs associated with the transformation of UED's business to the new model, and the necessary establishment of new business processes and systems under that model. To achieve the performance improvements projected by UED, these costs are unavoidable as UED moves from its existing business model to the new arrangements defined by Project 7/11. UED's Board and management concur with AT Kearney's opinion that the new business model will deliver significant benefits to UED and its customers compared to a projection of costs under the current arrangements.

As shown in Figure 5-1, forecasts of transformation operating expenditure are also included in the second main expenditure category adopted for forecasting purposes, namely UED's internal costs. The functions and services that UED intends to provide from within the business are listed in Table 3-2.

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.

The fourth and final main category of expenditure adopted for forecasting purposes is capital expenditure. An overview of the capital expenditure forecasting methodology is provided in section 6.3.

In the case of the three operating expenditure forecasting categories described above, detailed spreadsheet models are applied to develop cost forecasts for each service. For a detailed description of these models, please refer to KPMG's report which is provided as an appendix to this submission. The assumptions and key variables that drive these cost forecasting models are discussed in detail in section 5.4 below.

As noted in Figure 5-1 above, the forecasting process is designed to ensure that the following expenditure is removed from the data used to derive UED's forecasts of operating expenditure for direct control services:

- operating expenditure attributable to Multinet,

- expenditure associated with program delivery which is allocated to capital expenditure in accordance with UED's capitalisation policy; and
- operating expenditure associated with AIMRO activities that are outside the scope of this Regulatory Proposal.

Figure 5-1 also shows that UED budget data (which is prepared on a financial year basis) is subject to a process to align the forecast cost information to regulatory years in order to produce five years of forecasts as required by the Rules. A process relates to the application of UED's cost allocation methodology (CAM) to verify that all expenditure included in the forecast for the purpose of this Regulatory Proposal is properly allocated to direct control services in accordance with the requirements of the Rules.

As noted above, Figure 5-1 shows that UED's methodology for forecasting operating expenditure requires as a first step the identification of those services that are to be provided by an outsourced service provider, and those which are undertaken within the business. As discussed in section 3.2, UED adopted a rigorous approach in determining which services should, in future, be provided within the business in order to optimise cost and service performance across all business activities. Further information regarding the derivation of UED's operating expenditure forecasts is provided in section 5.5 below.

5.4 Key variables and assumptions for the forthcoming regulatory control period

Clauses S6.1.2(3) and (5) of the Rules requires that a building block proposal must contain:

- the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables; and
- the key assumptions that underlie the operating expenditure forecast.

As noted in Chapter 6 of this submission, UED's asset management plan contains detailed information on the key variables and assumptions that underpin UED's operating (and capital) expenditure forecasts. UED's asset management plan is discussed in sections 4.3, 4.4 and 4.5, and is included as an appendix to this submission.

In previous price determinations conducted by the ESC, operating expenditure has been regarded as a recurrent expense, which may reduce over time as genuine efficiency gains are achieved, subject to changes in the scope of operating activity and the volume and quality of outputs produced. The ESC's approach to forecasting operating expenditure relied on the incentive properties of the regulatory framework, and did not require a detailed "bottom-up" forecasting approach.

For the period covered by this Regulatory Proposal, however, UED has embarked upon a competitive tendering process to determine the terms and conditions for those services that are most suited to outsourcing. Whilst UED's asset management plan determines the required volume of services for the forthcoming regulatory period, it is a matter for bidders to forecast input costs, such as labour and materials. UED's role in relation to outsourced services is to select a bidder that provides the most attractive offering in terms of price, service and expected performance.

In contrast to outsourced service provision, costs incurred within the business will depend to a greater extent on forecast variables and assumptions. For example, where UED intends to provide services within the business that were previously out-sourced, staff costs will be an element in forecasting operating expenditure. An estimate of staff costs for the forthcoming regulatory period will depend on estimates of staff numbers and wage rates over the regulatory period. It is not necessary or appropriate for UED to forecast these variables in respect of outsourced services.

Given the different approach that must be adopted in relation to outsourced and services provided within the business, the variables and assumptions that underpin these forecasts are discussed in sections 5.4.1 and 5.4.2 respectively.

5.4.1 Key variables and assumptions for outsourced services

As discussed in Chapter 3 of this Regulatory Proposal, the competitive tender process has led to the selection of a preferred bidder. The bid offer is sufficiently detailed that it constitutes an offer that is capable of acceptance. The key variables and assumptions that underpin this offer reflect the information provided by UED to the bidders. In particular, for each of the outsourced service packages UED:

- identified activities that it requires the service provider to undertake as part of the service package; and
- quantified levels or volumes of activity that it anticipates to be required for each of the five years of the contract period. The levels of activity were developed from historical data, and on the basis of UED's expectations and knowledge of network and market developments and requirements, assisted by data and information provided by JAM.

As noted above, UED's asset management plan contains detailed information that is also relevant to UED's operating expenditure for services delivered within the business. UED's asset management plan is discussed in sections 4.3, 4.4 and 4.5, and is included as an appendix to this submission.

This information was provided to respondents to the RFP, and was further refined in the later stages of the bidding process. As explained in section 3.3, the selection of the preferred bidder followed the completion of the Target Cost Establishment (TCE) phase of the bidding process. The outputs of the TCE phase were:

- five-year financial targets for the delivery of the services, including:
  - o binding targets for operating and maintenance expenditure over five years;
  - o targets and a rate card for high-volume small capital expenditure;
  - o non-financial performance targets for the delivery of the services;
  - o a proposed agreement (including binding margins and performance incentive arrangements) for the delivery of the services being tendered; and
  - o documented detailed assumptions supporting the cost estimates; and
- plans and targets showing how each bidder intended to transition the services from JAM, the current service provider, and to subsequently deliver the Services in conjunction with the business in a manner that best meets UED's business objectives.

All bidders had access to UED staff during the TCE Stage, to ensure that the plans and associated targets were based on common data and assumptions and were of equal quality and credibility. During the TCE Stage, bidders were competing with one another to develop plans and associated targets that represented the best way forward for UED in terms of value-for-money, non-financial outcomes, and management of risks. As noted earlier, the bidding process was also subject to a probity plan and audit.

Given the confidential nature of the information that was provided to bidders during the TCE process and the bidders' responses, UED cannot provide full details in this Regulatory Proposal. Further detailed information will, however, be provided to the AER on a confidential basis.

The tendering process establishes a three-limb model for an input cost. The three-limb model was designed to avoid incentives for a service provider to profit from under or over-servicing, which can be the case with fixed price or cost-plus pricing mechanisms. The basic components of the compensation mechanism are:

- Reimbursable Costs or Limb 1: Payment of actual cost of service provision, including costs directly incurred in performing and managing the services, and overhead costs directly incurred as a result of performing or supporting the services;
- Contribution Fee or Limb 2: Payment of a contribution towards corporate overheads and profit, calculated as a percentage of agreed budgets for Limb 1 costs, using the percentage established through the tender process; and
- Limb 3 (Performance Payment): Payment of an incentive sum (which may be positive or negative), depending on actual performance compared to target for various agreed financial and non-financial measures.

This form of 'three-limb' compensation mechanism is commonly used for complex contracts where simpler contractual models have been found to be sub-optimal. In particular, it is noted that:

- The compensation model adopted by UED in the contract used to obtained priced proposals (including binding targets underpinning UED's cost forecasts) is modelled on the mechanism detailed in the *Project Alliancing Practitioner's Guide*, Victorian Department of Treasury and Finance, 2006[21].
- A study of Australasian contracts using commercial mechanisms similar to that proposed by UED identified a total 217 alliance projects with a combined value of at least $65 billion between 1996 and 2008[22].

In addition, it is noted that AT Kearney has advised that the mechanism outlined above creates a contractual environment where client and service provider's objectives are strongly aligned, and both parties 'win' or 'lose' together, rather than an environment where one party wins or loses at the other's expense. This achieves a range of efficiencies both in initial pricing, by avoiding either party assuming inappropriate risks, and in service delivery,

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[21] **This manual is available from : http://www.dtf.vic.gov.au/CA25713E0002EF43/WebObj/CompleteProjectAllianceGuide/$File/Complete%20Project%20Alliance%20Guide.pdf**

[22] **See *Report on Project alliancing activities in Australasia*, Alliancing Association of Australasia with RMIT University, 2008.**

by minimising non-value-adding-activity and ensuring that the response to any problems is to focus on resolution rather than blame, delay, and consequent exacerbation.

The Limb 1 and Limb 2 costs provided by the competing respondents who participated in the TCE Process were recorded in Excel spreadsheets known as “TCE templates”. This data then formed the inputs to the models that calculated the total costs for each outsourced service package for each respondent. This information, which effectively summarises the underpinning variables and assumptions adopted by bidders, will be provided to the AER on a confidential basis. UED’s expenditure forecasts in this Regulatory Proposal do not include any Limb 3 costs, which could be positive or negative depending on the service provider’s actual cost and service performance.

A remaining uncertainty that cannot be resolved at this time is whether JAM will exercise its right to match the bid from the preferred tenderer. UED’s tender evaluation process indicates that JAM will need to make significant efficiency improvements and transform its business processes and systems if it is to match the winning bid. In effect, by holding JAM to the outcomes from the tender process, the operating expenditure forecasts presented in this Chapter are insensitive to whether JAM decides to match.

5.4.2 Key variables and assumptions for services provided within the business

UED’s internal costs comprise the costs of services that are to be brought within the business, together with the costs of Project 7/11 support costs and other corporate services costs including those associated with the following functions:

- financial reporting;
- company secretarial;
- regulatory strategy and management;
- high-level IT management and governance;
- high level asset management and governance; and
- performance management of the service providers.

The internal costs are largely the costs of staff. Overheads, such as office accommodation costs, are assumed to be driven by staff numbers. Other overheads such as external audit cost are fixed cost estimates.

Staff numbers have been built up from UED’s Resource Plan (of July 2009). The staff numbers have been determined on the basis of assumptions of the number of resources that UED will need to operate its new business structure successfully. UED has documented planned organisation charts for its staff structures, including starting dates for different positions, based on:

- UED’s 2002 (pre-OSA) organisation charts;
- JAM’s 2009 organisation charts;
- a review of JAM resources allocated to the UED business in 2009;
- a number of utility benchmarks from Europe;

- an examination of staffing levels and organisation structures of other Australian distribution businesses; and
- analysis and reviews by UED's functional heads.

Until July 2014, the Turnkey Service Provider will also manage the consortium of service providers and their subcontractors. In July 2014, the consortium will be disaggregated and UED will operate individual contracts with each of the consortium members. UED's functional heads have estimated that three additional full time employees (FTE) will be required as a consequence of the disaggregation at that time.

Salaries are based on total compensable remuneration (including superannuation) plus on-costs. UED estimated pay rates and referred to benchmarks, with assistance from AT Kearney. Details of UED's models, variables and assumptions will be provided to the AER on a confidential basis.

In relation to labour rates, work by BIS Shrapnel[23] on behalf of distributors suggests that there are significant pressures on the Victorian electricity distribution Sectoral Labour Market.

BIS Shrapnel comment that skilled labour shortages and an ageing of the workforce remain significant drivers of non-EBA wages growth in the utilities sector. Although the current downturn will lead to an easing in overall skilled labour shortages for some professions relevant to the utilities sector, BIS Shrapnel still expect shortages of engineers and engineering managers – key professionals in the utilities sector.

Once economic conditions improve and demand for labour recovers, BIS Shrapnel expect higher wages growth in non-EBAs, as employers bid up wages for skilled labour in scarce supply. BIS Shrapnel expect wages under individual arrangements to increase strongly towards the end of the forecast, with the consequence that increases in the utility section in Victoria will average 2.6 per cent per annum over the seven years to 2015. Accordingly UED has reflected this assumption in its forecast of internal labour costs. UED notes that the winning bid price has not been adjusted to reflect this BIS Shrapnel forecast. Any forecast price increase by bidders have been forecast by the bidders and included in their market price forecast.

5.4.3 Other key variables

JAM and UED are currently in dispute in relation to the interpretation of aspects of JAM's right to match under the Operating Services Agreement with JAM. The dispute concerns the nature and scope of the offer made by UED to JAM under JAM's right to match. The fact that JAM has a right to match under the Operating Services Agreement is not in dispute, nor is the requirement that JAM match the pricing under the winning bid.

Irrespective of whether or not JAM exercises its right to match, the offer presented to JAM will be based on the best offer which UED has received from the market. The dispute with JAM is not expected to impact:

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23 **BIS Shrapnel, Wages Outlook for the Electricity Distribution Sector in Victoria, August 2009.**

- UED's operating and capital expenditure forecasts in this 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;
- UED's ability to transform its business in the manner described in this Regulatory Proposal, including implementing the two region model.

Unless UED and JAM agree to settle these interpretative issues, the dispute could proceed to arbitration in early 2010. UED will update the AER in relation to any material developments relating to this dispute.

5.5 Operating expenditure forecasts by category

5.5.1 Introduction

This section provides further explanatory information on UED's operating expenditure forecasts by category. In particular, where appropriate, for each operating expenditure category the following information is provided:

- a short description of the types of activities that fall within the category;
- any particular issues or challenges arising in relation to those activities for the forthcoming regulatory period;
- brief commentary on the key drivers for the expenditure with reference to the relevant expenditure objectives in the Rules;
- commentary on whether the unit costs of doing the work are expected to increase or decrease;
- commentary on whether there is scope to substitute the proposed operating expenditure for capital expenditure; and
- an explanation of how opportunities to achieve efficiency savings have been recognised factored into the forecasts presented.

The forecast for each operating expenditure category is calculated as follows:

- Price from the TCE process
- Plus internal costs (including labour increases above CPI)
- Plus new/amended activities or volumes (as detailed in appendix B-7).

5.5.2 Routine maintenance expenditure

Expenditure in this category is associated with the current or programmed asset maintenance activities that are undertaken regardless of the condition of assets.

The forecast of expenditure in this category reflects the routine maintenance activities and plans detailed in UED's Asset Management Plan (a copy of which is provided as an appendix to this Regulatory Proposal).

This category includes all normal tree cutting, undergrowth control and waste disposal associated with sub-transmission and distribution system line tree clearing.

As noted elsewhere in this Regulatory Proposal, the new regulatory regime that will come into force with the new Electricity Safety Act is expected to lead to a significant increase in the costs of vegetation management over the forthcoming regulatory period. Section 19.7.4 of this Regulatory Proposal notes that there is insufficient certainty at this time to estimate the additional vegetation management costs associated with the new regime, so UED has proposed that the introduction of the proposed regulations be defined as a nominated pass through (regulatory change) event.

UED's forecast of expenditure in this category reflects the additional routine maintenance activities described in Table 5-2 below.

Table 5-2: Routine maintenance activities

Maintenance need	Activity
Zone substation Power Quality Meter Maintenance	In the 2001-05 EDPR decision UED was provided with the capital funds to install power quality meters in every zone substation and at the far end of a distribution feeder from each zone substation. The meters were installed as planned and the data collected was reported to the ESC as part of the annual performance reporting requirements. A routine maintenance policy is now recommended for these meters to ensure they remain in reliable service. The maintenance frequency recommended for all power quality meters is eight years. Routine maintenance is scheduled for the first time on the entire power quality meter population in 2011.
Rectify Steady-State Voltage Violations	Currently power quality monitors are installed in fixed locations, as required by the Electricity Distribution Code, to monitor compliance of voltage delivery. Such monitoring has revealed that steady state voltages are outside code limits at some times, at some locations. Such code violations are rectified as and when they are detected by the power quality monitors, and also in response to customer complaints about low and high supply voltage. The rollout of advanced interval meters (with high and low voltage monitoring incorporated) to residential homes is expected to reveal a significant number of customers with steady-state voltage levels exceeding the Electricity Distribution Code requirements. Once these issues are identified, it is necessary to undertake confirming analysis and determine, then adjust distribution substation tap positions to ensure compliance with the Code, resulting in increased operating costs.

Maintenance need	Activity
Disposal of Prescribed Waste	On 1 July 2009, new Environment Protection (Industrial Waste Resource) Regulations 2009 came into operations. UED needs to dispose of the waste generated by its operations in accordance with these regulations. The regulations reflect an EPA objective of Zero Hazardous waste to landfill by 2020. These changed regulatory obligations result in an increase in the cost of waste disposal including testing, transportation, and disposal at landfill sites. In addition new regulations require a shift of risk from the EPA to UED. Regulations have increased costs to encourage reuse or recycling options before sending material to landfill. Specialist consultant costs are required for the following activities: • UED needs to determine what resources are available, and the required timeframes, to update existing procedures and processes; • UED must review the new guidelines and incorporate them into updated procedures; • UED must develop a list of prescribed wastes that could be considered for secondary beneficial reuse or recycling. The scope for exemptions must also be examined; and • Environmental auditors will be engaged to review UED's list of prescribe waste, and to ensure UED compliance with all requirements.
Private Overhead Electric Lines (POEL) inspection cycle change	POELs are low voltage overhead consumer mains, originating from the UED point of supply at the first pole on the property, to the first building on the property. Maintenance of POELs and the associated infrastructure (such as poles) is the responsibility of the electricity consumer. However, UED is required by regulation to inspect POELs on a regular basis. The current practice of UED (since 2001) is to inspect POELs in High Bushfire Risk Areas (HBRA) on a three year cycle, and in the Low Bushfire Risk Area (LBRA), on a four year cycle. In 2003 ESV changed the regulations to three year cycle for HBRA and three year cycle for LBRA. Notwithstanding this, UED has maintained its pre-existing practice (of inspecting LBRA on a four year cycle) in all Bushfire Mitigation Plans (BMP) submitted to ESV for approval. In its assessment of UED's 2008/09 BMP, ESV has flagged that it had not formally approved UED's four year inspection cycles for low risk areas and that UED is required to comply with the regulations. As a result, from 1 July 2009, and in line with the 2009/10 Bushfire Mitigation Plan, UED has brought forward those POEL inspections that would require inspection before 1 May 2010 to adhere to the three year inspection cycle outlined in the regulations. The change in inspection cycle has created additional inspection costs.

The costs of these activities are reflected in the expenditure forecast for the routine maintenance category.

As noted in UED's Asset Management Plan, the level of UED's maintenance expenditure is consistent with an optimal mix of capital and operating expenditure over the asset life cycle.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-2 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period.[24].

Table 5-3: Forecast operating expenditure - routine maintenance

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	
7.2	7.3	7.4	7.4	7.4	36.7

5.5.3 Condition-based maintenance expenditure;

This category includes the maintenance activities that are based on inspection or assessment of the condition of an asset, excluding the activities that are part of the routine maintenance expenditure category.

The forecast of expenditure in this category reflects the condition-bound activities and plans detailed in UED's Asset Management Plan (a copy of which is provided as an appendix to this Regulatory Proposal).

As noted in UED's Asset Management Plan, the level of UED's condition based maintenance expenditure is consistent with an optimal mix of capital and operating expenditure over the asset life cycle.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-4 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[25].

Table 5-4: Forecast operating expenditure - condition based maintenance

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
11.0	10.5	10.5	10.5	10.5	53.0

Amounts shown in real 2010 terms.

5.5.4 Emergency maintenance expenditure

This category includes the expenditure that relates to the activities that restore a failed component to an operational state. It includes all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by breakdown, in making intermediate operations and/or repairs necessary. Expenditure relating to the

[24] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

[25] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

replacement of assets under emergency maintenance conditions is capitalised as a replacement asset. This category only includes expenditure to make the situation safe, or to make repairs as required to restore supply.

As noted elsewhere in this Regulatory Proposal, UED engaged AECOM to provide an assessment of the impact of climate change on network performance and expenditure requirements for the 2011-2015 regulatory period. Analysis by AECOM indicates that UED's network reliability performance is adversely impact by wind storms. Apart from the damage caused by wind storms, operating expenditure also increases for "faults and emergency" work, emergency management preparation and loss of productivity due to re-scheduling of planned work.

The climate change model indicates that the frequency of wind storms over the 2011-15 period is expected to increase, compared with that observed over the current regulatory period. As a result, operating expenditure is expected to increase. The AECOM report concludes that the potential effect of wind on network performance and operating costs was found to be significant, with likely increases in costs associated with future storm management and productivity loss estimated to be as high as approximately $1,300,000 per annum.

The AECOM report is included as an appendix to this Regulatory Proposal.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-5 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[26].

Table 5-5: Forecast operating expenditure - emergency maintenance

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
6.0	5.8	5.8	5.8	5.8	29.3

Amounts shown in real 2010 terms.

5.5.5 Network systems operations

This category includes the recurrent costs associated with the operation of the network including, but not restricted to, operational switching personnel, outage planning personnel, provision of authorised network personnel, demand forecasting, asset planning and strategy, procurement, logistics and stores, (IT) costs directly attributable to network operation, insurance costs and land tax costs.

Demand forecasting costs include labour, material and IT charges for the purpose of forecasting peak demand, energy growth and customer numbers in the Distribution Licence area.

[26] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

There is upward pressure being placed on network systems operations expenditure in three particular activities, namely: compliance costs under the new Electricity Safety Act; assessment of potential applications of AMI to network management and operation; and insurance. Further details are provided below.

The second driver of cost increases is the forecast requirement to undertake evaluation and assessment of technology capable of monitoring and potentially controlling distribution plant through AMI. This will involve:

- Analysis of raw data derived from AMI for potential application to network management decision making and run information system trials to support decision making;
- Evaluation of impacts, costs and benefits of AMI; leveraged, extended and deployed to support improved management of faults response, quality of supply investigation, electrical losses measurement and management, voltage profile control, power factor monitoring and control;
- Evaluation of impacts, costs and benefits of AMI to provide network data (network status, network tariff etc) to customers through the HAN and assess the degree of changed customer behaviour to a broad range of network 'signals'.

This investigation will commence in mid-2011 once sufficient AMI has been rolled out and AMI management systems are bedded in.

The third major driver of cost increases in the network systems operations category is the effects of climate change. AECOM conclude that"

> " … Opex considerations for wind remain aligned with CSIRO Mk3.5 to ensure consistency of operational considerations within that scenario. Given that the CSIRO Mk3.5 model projection represents a best estimate of the likely mean climate change outcomes, it provides a reasonable basis for developing operational expenditure forecasts that represent the expected cost of climate change to UED."[27]

UED has also received advice from its insurers that premiums are forecast to rise. In particular, Marsh and McLennan have provided advice that insurance premiums will rise substantially due to:

- the heightened exposure (globally) to wild fire risk; and
- the potential for claims to arise from the February 2009 Victorian bushfires.

The Marsh and McLennan report is attached as an appendix to this Regulatory Proposal.

UED has assessed whether there is any potential for substituting the proposed operating expenditure for capital expenditure, and it has been found that no such potential exists for expenditure in this category.

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[27] **Assessment of Climate Change Impacts on United Energy Distribution Network for 2011 – 2015 EDPR, 7 September 2009.**

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-6 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[28].

Table 5-6: Forecast operating expenditure - Network systems operations

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
32.5	31.7	32.2	32.2	32.3	160.8

Amounts shown in real 2010 terms.

5.5.6 SCADA and network control

This category includes the cost of staffing the 24 hour control centre(s). Key activities include the provision of energy management services for the safe and efficient electrical operation of the network, to facilitate pre-arranged and emergency work.

A major driver of the expected increase in expenditure in this category for the forthcoming period is a planned protection review. Protection equipment is installed to detect abnormal supply network conditions (such as faults) and initiates automatic disconnection of the affected supply network. Effective operation of the protection equipment is therefore crucial in ensuring public health and safety as well as minimising damage to UED's network assets and equipment.

UED is required by the Network Asset Regulations to maintain effective protection system performance, and this means effective setting of the protection equipment. As the distribution network continues to grow in size, complexity and load requirements, periodic comprehensive protection setting review is required. The last comprehensive review was conducted in 1998-99.

UED has examined whether there is any potential for substituting the proposed operating expenditure in this category for capital expenditure, and it has been found that no such potential exists.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-7 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[29].

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[28] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates..**

[29] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates. .**

Table 5-7: Forecast operating expenditure - SCADA and network control

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
5.8	5.9	5.9	5.9	5.9	29.2

Amounts shown in real 2010 terms.

5.5.7 Billing and revenue collection

This category of expenditure includes costs associated with the billing of retailers for use of the distribution system, and the associated collection of distribution revenue from retailers. This category comprises the following services:

- the invoicing function;
- the accounts receivable function;
- the credit and bad debt collection function; and
- the customer transfer function.

Invoicing costs include the labour, postage, stationery and outsourcing associated with:

- running integrity checks on the metering data;
- calculating and forwarding invoices; and
- preparing consolidated statements including invoices, credits and payments.

Accounts receivable costs include the labour, postage, stationery and outsourcing associated with:

- receipt of monies due;
- forwarding cash received to the bank;
- reconciliation of cash receipts to bank statement and cash receipts ledger;
- identifying slow-paying accounts;
- production of statements; and
- managing over- and under-payments.

Credit and bad debt collection costs include the labour, postage, stationery and outsourcing associated with:

- the conduct of credit checks;
- resolving any disputes in relation to invoices;
- undertaking revenue 'fraud' investigations; and
- an allowance for bad debts that are incurred from retailers who hold a Retail licence.

The key driver of expenditure in this category is the number of invoices issued and the number of invoice errors. UED is not expecting any increase in the unit cost of billing and revenue collection over the forthcoming period.

This category also includes the forecast cost of managing and administering the Premium Feed in Tariff as detailed in UED's pass through application dated 6 November 2009. Costs have not been included for the 60 cent per KWh rebate.

UED has examined whether there is any potential for substituting the proposed operating expenditure in this category for capital expenditure, and it has been found that no such potential exists.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-8 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[30].

Table 5-8: Forecast operating expenditure - billing and revenue collection

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
2.6	1.8	1.8	1.9	1.9	10.0

Amounts shown in real 2010 terms.

5.5.8 Customer service

This operating expenditure category includes the costs of providing the following services to distribution customers includes:

- facilitating the reporting to the Distribution Business of network faults and safety hazards, and complaints about the quality and reliability of supply from customers;
- responding to queries, for example, from retailers, customers, builders and contractors, on new connections, disconnections and reconnections;
- responding to queries, for example from customers, builders and contractors, on improving power factor or load factor;
- call centre costs are directly attributable to or caused by the provision of the above services are included in this category; and
- managing and maintaining relationships with UED's large customers in dealing with matters such as managing capacity to meet specific demand requirements, quality of supply and reliability of supply.

The key drivers of costs in this category are the number of customer complaints, network performance and the number of fault calls. UED is not expecting any increase in the unit cost of billing and revenue collection over the forthcoming period.

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30 **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

Total expenditure in this category is expected to increase in line with customer number forecasts.

UED has examined whether there is any potential for substituting the proposed operating expenditure in this category for capital expenditure, and it has been found that no such potential exists.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-9 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[31].

Table 5-9: Forecast operating expenditure - customer service

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
8.1	8.2	8.2	8.2	8.2	40.8

Amounts shown in real 2010 terms.

5.5.9 Advertising, marketing and promotions

This category includes advertising and marketing activities directly attributable to the provision of distribution services. Included in this cost category are:

- providing information to customers, and conducting promotional activities, in order to improve the utilisation of the network assets by improving the power factor or the load factor;
- providing contact telephone numbers for fault reporting, for example through bill inserts;
- publicising reliability targets and communicating with network customers on reliability matters;
- communicating with customers on distribution matters, for instance, providing notice of planned interruptions and communicating network tariff changes to customers;
- educating the public and the construction industry on network-related electrical safety such as Dial-Before-You-Dig and 'look up and live' campaigns; and
- activities arising from the Distribution Business obligations in relation to the quality of supply.

DNSPs are required to provide a customer charter to each new customer and to all customers once every five years. UED provides a customer charter once every five years as required. Consistent with previous practice UED intends to distribute its customer charter to all customers in the first half of 2011. The cost of undertaking this exercise includes fully reviewing the charter to take into account the AER's decision on this

[31] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

Regulatory Proposal, and any other changes since the current version was produced. The cost also includes a mail out to all end-use customers. These costs are included in the expenditure forecast for this category for the next regulatory period.

The potential for substituting the proposed operating expenditure in this category for capital expenditure has been examined by UED and it has been found that no such potential exists.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-10 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[32].

Table 5-10: Forecast operating expenditure - advertising, marketing and promotions

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
1.8	0.6	0.6	0.6	0.6	4.3

Amounts shown in real 2010 terms.

5.5.10 Regulatory costs

Operating expenditure in this category includes the costs of meeting economic regulatory requirements as they apply to the Distribution Business. Included in this cost category are:

- costs associated with staffing the regulatory function, including a Regulatory Manager;
- and staff, covering both state and federal economic regulation;
- costs associated with providing information requested by various regulators;
- costs associated with preparing submissions to the various regulators in response to consultation processes administered by them;
- costs associated with participation in the AER's reviews of price controls and the development and implementation of standards and procedures;
- costs associated with implementation and administration of new network planning and consultation requirements required under the proposed national framework for distribution network planning and expansion; and
- costs of non-financial regulatory audits.

The AEMC recently issued a report to the Ministerial Council on Energy ("MCE") recommending the implementation of a new national distribution planning framework.

The planning framework would apply to all distribution capital investment with the exception of asset replacement projects. The framework requires considerably more work to satisfy

[32] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

investment criteria, including the conduct of a Regulatory Investment Test – Distribution ("RIT-D") for all projects above a $5 million threshold. While the exact details of additional requirements will not be known until the MCE has considered the AEMC's final report, the table below sets out UED's estimate of the additional work and resources that will be required.

Additional Requirements	Additional activities	Annual man hours and $
Increased reporting requirements for the Distribution Annual Planning Review ("DAPR")	Time to collect and collate additional information for the DAPR	150 man-hours
DAPR	Hold annual public forum on DAPR	120 man-hours + $10k for external review
Annual Planning Process	Joint Planning Process with AEMO and SPI PowerNet – a 2 hour meeting every two months	75 man-hours
Demand side engagement	• Preparation, review, update and publication of Demand Side Engagement Strategy • Setup and maintain a database of demand management proponents, proposals including DNSP's assessments	80 man-hour 50 man-hour
Regulatory Investment Test for Distribution (RIT-D) and Transmission Connection (RIT-T)	Carry out Regulatory Investment Test on all augmentation projects where the most expensive option exceeds $5 million	7 RIT-D p.a. at 160 to 280 man-hour per RIT-D. Average 1540 man-hour
Dispute resolution process	Manage and respond to dispute raised on RIT process	48 man-hour

Amounts shown in real 2010 terms.

The costs associated with implementing and administering these new requirements is included in the forecast operating expenditure for this category.

A further driver of cost increases in this category over the forthcoming regulatory period is UED's additional reporting requirements under the National Greenhouse and Energy Reporting Scheme ("NGERS"). UED triggers the 25 kilotonne CO_2-e threshold under this scheme and hence the company has a mandatory obligation to report under the scheme. NGERS has extremely complex reporting requirements, and it includes considerable financial and legal penalties. As a result, compliance with the NGERS reporting requirements gives rise to a need for specialist skills in the form of external auditors to provide assurance, and external legal advice to ensure that all regulations are interpreted soundly and fully complied with. The costs of these additional activities are included in the operating expenditure forecast for this category.

The category also includes the cost relating to an ESC draft decision for Electricity Distributors' Communications in Extreme Supply Events. This draft decision requires UED to:

- Write to customers in October each year informing them of the distributors' role and their contact details, including their website address;

UED estimates that this decision will cost consumers on average $650,000 per annum. This will include the cost of preparing the mail-out, postage and handling, and customer queries relating to the mail-out.

The potential for substituting the proposed operating expenditure in this category for capital expenditure has been examined by UED and it has been found that no such potential exists.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-11 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period[33].

Table 5-11: Forecast operating expenditure - regulatory costs

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
2.7	1.8	1.8	2.0	2.3	10.0

Amounts shown in real 2010 terms.

5.5.11 Other operating costs

This category comprises finance, human resources, and other costs that are directly attributable to or caused by the provision of distribution services by the Distribution Business in accordance with its Distribution Licence.

The finance function comprises:

- financial accounting;
- management accounting;
- statutory and regulatory reporting; and
- other financial functions.

Financial accounting costs include the labour and materials that are directly attributable to or caused by the Distribution Business for:

- general ledger maintenance, e.g. reconciliations;
- accounts payable – raising and processing of purchase orders, matching invoices, accounts payment, cheque production, controlling credit ledger, dispute resolution, administration of business cards;

[33] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates.**

- banking – preparation of bank reconciliations, banking function, stop payments and reissues, EFT management, processing dishonoured cheques and follow up;
- compliance with Unclaimed Monies Act;
- fixed asset accounting – maintenance and updating of Fixed Assets Register, Financial, Regulatory and Taxation requirements; and
- fleet – administration of motor vehicle fleet maintenance, leasing, operating costs, employee salary packaging.

Management accounting costs include the labour and materials that are directly attributable to or caused by the Distribution Business for:

- preparation of monthly management accounts;
- divisional reporting and forecasting;
- accounts receivable (non-electricity);
- tax and financial advice; and
- job costing.

Statutory and regulatory reporting costs include the labour and materials that are directly attributable to or caused by the Distribution Business for:

- annual statutory accounts;
- taxation – income tax return, FBT return, payroll tax, reconciliation of PAYE, calculation and payment of instalments, GST, salary packaging;
- audit fees;
- preparation of annual regulatory reporting to the Commission; and
- completion of ABS surveys.

The other financial function costs include the labour and materials directly attributable to or caused by the Distribution Business for:

- Treasury;
- payroll function – data entry of timesheets, preparation of payroll data for processing, payroll review and provision of payroll advice, administration of superannuation;
- development and implementation of accounting standards, and internal policies and procedures;
- financial systems administration – general ledger, fixed assets, payroll, budgets;
- preparation of projected income statement, cash flow statement and balance sheet; and
- the proportion of the operating costs for the ERP system and specialist software caused by the finance function.

The human resources function comprises:

- corporate human resources function;
- maintenance and management of human resources records;
- industrial and employee relations; and
- occupational, health and safety.

Included in this cost category are costs that are directly attributable to or caused by the Distribution Business for:

- development and implementation of human resources strategy, policies and procedures;
- training courses for personnel in the human resources group;
- union negotiations;
- dispute resolution, relating to human resource issues;
- recruitment of employees;
- monitoring equal employment opportunity;
- performance development and reviews;
- salary packaging;
- workers compensation management; and
- workplace accident investigating and reporting.

The proportion of the operating costs for the ERP system and specialist software caused by the human resource function should also be included.

As noted in chapter 3, UED intends to in-source most of the functions listed above during the forthcoming regulatory period. Internal labour is therefore the main costs component of this operating expenditure category. As noted in section 5.4.2 internal labour costs are expected to increase at a rate of 2.6 per cent above inflation during the forthcoming regulatory period. UED's expenditure forecasts for this category are based on providing all of the services listed above internally solely in relation to UED's standard control services.

The potential for substituting the proposed operating expenditure in this category for capital expenditure has been examined by UED and it has been found that no such potential exists.

Pursuant to the requirements set out in clause S6.1.2(7) of the Rules, Table 5-12 below sets out UED's forecast of operating expenditure for this category for each year of the forthcoming regulatory period, along with data showing actual expenditure for each year of the current period[34].

[34] **Data relating to actual annual expenditure for the previous period is set out in the RIN templates..**

This category also includes the maintenance, software licensing and repair costs of UED's information technology systems. It also includes the development and implementation of an information technology (IT) strategy and costs that are directly attributable to or caused by the operation (including maintenance, upgrades, and administration) of the IT infrastructure, and in particular it includes operating expenditure associated with:

- personal computers and networks;
- intranet, including server and network applications (for instance, email);
- helpdesk; and
- PABX infrastructure.

Components of the ERP system not otherwise assigned to business processes are included in this cost category.

UED is planning to make significant capital investments in new and replacement IT assets over the forthcoming regulatory period. The forecast of IT operating expenditure over the period is derived from the IT AMP, a copy of which is provided as an appendix to this Regulatory Proposal.

Table 5-12: Forecast operating expenditure - other operating costs

Forthcoming regulatory period					Total
2011	2012	2013	2014	2015	$M
41.6	42.0	40.9	40.1	39.2	203.8

Amounts shown in real 2010 terms.

5.5.12 Self-insurance

The Australian Energy Regulator has previously granted allowances for self-insurance in distribution and transmission determinations. Examples of relevant decisions include the NSW final distribution determination, 2009-10 to 2013-14[35], and the transmission determination for SP Ausnet, 2008-09 to 2013-14 (AER, 2008a1). In its Regulatory Information Notice (RIN) for UED, the AER has also set out the qualifying criteria to be applied when determining provisions for self-insurance.

Sections 4.3, 4.4 and 4.5 of the RIN discuss the requirements to be satisfied in any application for a self-insurance allowance. In particular, UED is to provide:

(i) A description of the risk in respect of which self-insurance is being sought.

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[35] **AER (2009d1). Final Decision. New South Wales distribution determination, 2009-10 to 2013-14. Australian Energy Regulator, 28 April 2009.**

(ii) A description of the calculation of the self-insurance risk premium (for instance, probability multiplied by consequence), including the size of the premium proposed for each regulatory year.

(iii) A report from an actuary, who is qualified to provide such advice, on the calculation of each self-insurance risk premium; and

(iv) Any quotes obtained from external insurers.

UED is also obliged to explain:

(i) Why compensation should be provided for the risk.

(ii) Where insurance is available from an external insurer or insurers, and an insurance quote has been obtained:

- o The insured sum to which the quote relates.
- o The annual amount of the premium thus obtained.
- o The size of the deductible; and
- o The terms and conditions of the insurance; and

(iii) How and whether the risk for which self-insurance is being sought is not recovered through any other mechanism.

The approach to risk management by UED

Self-insurance is a risk mitigation mechanism that can be used to manage the risks which arise at the interface between:

- The operating expenditure allowances made available to UED.
- Externally sourced insurance; and
- Nominated pass through events.

Self-insurance is a prudent form of coverage against potential liabilities and losses which do not fall readily into any of the three categories mentioned above. Self-insurance is also available to cover the co-payments which UED would be required to contribute in the context of an insurance claim under its existing policies. Compensation for the self-insured risks is not available through the weighted average cost of capital (WACC).

United Energy is proposing to self-insure against the risk of adverse exogenous events such as storms, bush fires and third party damage to network assets. These risks are borne by the business in the course of providing Standard Control Services. The risks are unforeseeable, with UED unable to predict the probability, severity and cost impact of the severe events. The inherent uncertainties also mean that UED is unable to prepare an accurate forecast for inclusion in the baseline operating expenditure building block, which is to be provided in conjunction with the company's Regulatory Proposal.

During the current regulatory period, UED has relied upon external insurance to provide a risk management service. However, external insurance is incomplete, and cannot offer coverage against the full range of possible future events. Consequently, UED has been left exposed. The company has incurred expenses as a result of unfavourable phenomena such as storms, but has had limited capacity to recoup the costs.

United Energy confirms that it is able to undertake credible self-insurance. The signed minutes of a board resolution to self-insure have also been provided as an attachment to this Regulatory Proposal. The Board resolution identifies each of the risk categories for which a self-insurance allowance has been sought.

The extent of self-insurance varies by risk category. For certain types of risk, self-insurance has been undertaken to provide coverage for the residual exposure which remains as a result of an insurance policy deductible. For other types of risk, including the risk of widespread damage to poles and wires during periods of extreme weather, self-insurance is intended to provide cover for the full extent of the possible loss.

Treatment of self-insurance in the 2011 to 2015 regulatory control period

United Energy engaged Aon Global Risk Consulting in July 2009 to undertake a review of current insurance arrangements, and to assess the potential for self-insurance to be included in the firm's Regulatory Proposal for 2011 to 2015. Aon was selected for the role because it was able to offer a fully documented and robust modelling approach, underpinned by comprehensive, in-house actuarial review.

Aon analysed a history of losses experienced by UED, concentrating on the deficits caused by events which lay beyond the bounds of United Energy's external insurance programme. For losses attributable to insured external events, Aon examined the co-insurance or deductible component of the overall insurance payout.

Aon also made use of the work prepared by other consultants retained by UED. These consultants include Trowbridge Deloitte (which was commissioned on a one-off basis in 2005 to calculate asbestos liabilities), Marsh Risk Consulting (which undertook a bush fire liability study in 2008), and Monarc Environmental (a firm currently involved in the evaluation of options for, and monitoring of the contaminated tract of land along Railway Parade, Dandenong). The relevant reports are Trowbridge Deloitte (2005)[36], Marsh (2008) [37] and Monarc (2009j)[38].

The report from Aon, and the accompanying actuarial statement, is provided along with this Regulatory Proposal. Aon has quantified the self-insured losses which should be incorporated into a potential self-insurance programme for the 2011 to 2015 regulatory control period. Aon has taken care to ensure that the losses which underpin its self-insurance projections are not already covered by United Energy's market insurance policies, and are not included in the baseline operating expenditure forecasts for the next regulatory control period. Furthermore, there are no losses which can be ascribed to structural failure resulting from poor construction or maintenance. UED believes that losses

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[36] **Trowbridge Deloitte (2005). Commercial-in-confidence advice on potential asbestos liabilities. An actuarial assessment prepared by Trowbridge Deloitte. 22 February 2005.**

[37] **Marsh (208). Bushfire Liability Study. Alinta LGA Ltd. Alinta/United Energy Distribution Network, Mornington Peninsula. Prepared by Marsh Pty Ltd. 11 September 2008.**

[38] **Monarc (2009j). Environmental Risk and Liability Estimates: 8-14 Railway Parade, Dandenong. Prepared by Monarc Environmental Pty Ltd. October 2009.**

due to component failure would not satisfy an important regulatory requirement whereby cost estimates used for self-insurance purposes should reflect the practices of a benchmark, efficient entity. In any case, there have been comparatively few instances of component failure in United Energy's history.

United Energy considers that self-insurance provisions should only be set aside in relation to Standard Control Services. Although the business risks involved in the provision of Alternative Control Services are similar to those inherent in the delivery of Standard Control Services, the potential losses are lower because of the smaller asset base involved. In addition, owing to the nature of Alternative Control Services, customer specific risks can be more readily accommodated on an individual customer basis rather than through a self insurance allowance.

5.5.13 Proposed self-insurance risks and associated costs for the 2011 to 2015 regulatory control period

Aon identified several risk categories after evaluating the historical data provided by UED. The Board of UED has drawn upon the work completed by Aon and has resolved to self insure against the following risks:

- public liability (excluding directors' and officers' liability);
- bush fire liability;
- asbestos liability;
- damage to UED property caused by third parties;
- extensive damage to poles and wires;
- contaminated land;
- environmental;
- insurer default; and
- fraud.

The proposed allowances for self-insurance are shown in Table 5-13, which also gives details of the insurance cover that is available, and that has been exercised, through contractual arrangements with external providers.

The risks are described further over the remainder of this chapter. The discussion draws upon the findings of the modelling work performed by Aon, and aims to address the requirements of the RIN.

Table 5-13: Details of proposed self-insurance risks for 2011 to 2015

	Values in $ million, current prices			
Type of risk	Self-insurance allowance	Insurance cover	Annual premium	Deductible
Liability (excluding D&O liability)	0.107	635.000	2.121	0.100
Bush fire liability	0.049			5.000

Type of risk	Values in $ million, current prices			
	Self-insurance allowance	Insurance cover	Annual premium	Deductible
Asbestos liability	0.024	0.000	0.000	0.000
Property	2.750	100.000	0.571	0.500
Poles and Wires	0.542	Nil	N/a	N/a
Contaminated land	0.479	Nil	N/a	N/a
Environmental	0.044	Nil	N/a	N/a
Insurer default	0.025	Nil	N/a	N/a
Fraud risks	0.003	Nil	N/a	N/a
TOTAL	**4.020**	**735.000**	**2.692**	**5.600**

Source: Self Insurance Risk Quantification for United Energy, undertaken by Aon Global Risk Consulting. Insurance coverage for UED arranged by Marsh Finpro Pty Ltd.

Liability risks

Liability risks include all of the amounts that UED is legally liable to pay as compensation for reasons to do with personal injury, property damage, advertising responsibility and the financial losses incurred by other parties. The liability assumed by UED under contract or agreement is also included.

The range of possible liability risks is discussed in the Aon report on self-insurance quantification[39]. The report explains the methods used to calculate the self insurance risk provision, and also presents the results of the assessment. The detailed modelling results are presented in an appendix, and all of the intermediate steps have been subject to actuarial review.

Aon has determined that, in respect of liability risks, a prudent self-insurance risk premium for United Energy would be $179,192, to be set aside annually. The premium can be broken down as follows:

- for general liability risks, excluding bush fire liabilities, an appropriate provision is $106,584;
- for bush fire liabilities, the self-insurance premium has been assessed to be $48,608; and
- for asbestos liabilities, a suitable self-insurance allowance is $24,000 per annum.

[39] **Aon (2009k). United Energy Self-Insurance Quantification Report, 2009. Prepared by Aon Risk Services Australia Limited. November 2009.**

Note that the self-insurance premium does not cover any form of liability for directors and officers.

An additional self-insurance provision of $24,000 per annum should also be retained to cover asbestos liabilities. Aon has calculated this amount after referring to an assessment of potential asbestos claims which was prepared for UED by Trowbridge Deloitte (Trowbridge, 2005).

For all potential liabilities, the purpose of self-insurance, is to make up for gaps in the general liability and professional indemnity insurance policies currently held by UED. Specifically, UED would be required to meet significant co-payments if a claim were lodged on the overall policy.

The company has comprehensive liability insurance policies in place and is part of an AEGIS energy syndicate. AEGIS is the lead insurer, however other insurers under-write different "layers" of the policy. The limit of liability under the policy is $635 million and has been at this level since 2006-07. The UILP programme, as it is described, was initially effected on behalf of the State Electricity Commission of Victoria (SECV).

The insurance coverage under the policy encompasses:

- bush fire liability;
- electro-magnetic fields;
- non-owned aircraft liability;
- excess motor vehicle liability;
- construction liability;
- failure to supply (including "pure" financial loss);
- cross liability;
- waiver of subrogation; and
- professional indemnity (up to $25 million).

The renewal premium for 2009-10 has increased substantially because of global bush fire exposure and the potential for claims arising from the February 2009 bush fires in Victoria (Black Saturday). The premium which has been paid for the period 30 September 2009 to 30 September 2010 is $2.12 million, up from $1.43 million for the corresponding period in 2008-09.

Insurance brokers, Marsh Finpro, have also anticipated continued upward pricing pressure for a number of years because of emerging market conditions. The premium is expected to increase by 10 to 15 per cent per annum over the forecast horizon. Marsh has also warned that if Australian and global bush fires continue in frequency and severity, or emanate from the UED assets, then the prospective increases in premiums will be higher. Moreover, if the trend of the past year continues, then traditional insurance may become less feasible.

Under the general liability policy, the deductibles for each claim, or for a series of claims arising out of one occurrence, have been described in the following terms:

- General, $100,000.

- Products and completed operations, $100,000.
- Non-Owned aircraft, $100,000.
- Electro-magnetic fields, $100,000.
- Professional indemnity, $100,000.
- Automobile, $1 million
- Bush fires, $5 million.

The deductibles are defined in the policy wording as "self-insured retention amounts". The work performed by Aon has ensured that the actual self insurance allowances proposed by UED have been computed in a reasonably scientific manner. Aon has, of course, taken into consideration the size of the deductibles.

UED will provide the AER with a copy of the general liability and professional indemnity renewal report for 2009-10. This policy document sets out the broad terms and conditions. If the AER requires further information, in relation to policy exclusions for example, then UED will obtain further details from its brokers, Marsh Finpro Pty Ltd.

Liability of directors and officers

United Energy has in place a policy to cover the potential liability of directors and officers of the company. The primary layer of the policy is under-written by American International Group, while the principal insurer supporting the excess layers is Chubb Insurance Company of Australia. The value of the cover is $80 million, in aggregate, with an insurance excess or deductible of $100,000. The limit of liability applies to any one claim and in aggregate during the policy period. The renewal premium paid by UED in 2009-10 has been $166,133.

No self-insurance assessment has been made in respect of the potential liability of the directors and officers of United Energy Distribution Holdings Pty. Ltd. Aon Global Risk Consulting considered that there was comparatively little likelihood of the company having to lodge a claim against the directors' and officers' policy. Aon also stated that losses which fall into this category occur somewhat randomly and unpredictably, rendering the modelling task impractical or unfeasible.

Bush fire liabilities

Under the terms of its general liability and professional indemnity policy, UED is required to meet the first $5 million of any claim for bush fire related damage, for which the firm has been found responsible. The implication is that United Energy carries a significant exposure to the potential losses resulting from a bush fire event. If more than one event were to occur per annum, then UED would be required to make the co-payment on more than one occasion. Accordingly, UED is proposing to self insure for the deductible component.

The assessment of the bush fire self-insurance premium has been documented by Aon in the self-insurance risk quantification report (Aon, 2009k).

Mount Martha and Arthurs Seat both lie within the UED distribution area. The bush fire maximum foreseeable loss study undertaken for UED (Marsh 2008) reported that there were significant fires in the Mount Martha area in January 1939. The SECV annual report for 1938-39 (SECV, 1939) also acknowledges the widespread impact on the electricity distribution system from bush fires throughout Victoria on black Friday (January 1939). Other smaller bush fires have also been recorded in Mount Martha and at Arthurs Seat, as recently as February 2009. To date, however, none of these fires has been caused by UED assets.

In its relatively short history, United Energy has not been subject to any major claims for losses resulting from bush fire incidents. Aon therefore deduced that the chances of a major bush fire in the territory served by UED were relatively remote. Aon incorporated a scenario of one $10 million loss occurring in the UED territory every one hundred years. Under its existing general liability policy, UED would be obliged to meet the first $5 million of the loss. Aon applied its risk modelling techniques and worked out that, in these circumstances, a suitable self-insurance allowance would be an annual amount of $48,608 (Aon, 2009k).

The assessed self-insurance premium assumes that there would be no losses above the liability policy limit of $635 million.

Asbestos liabilities

The risks in this category relate to possible future claims against United Energy as a result of the exposure of previous employees to asbestos, resulting in asbestos-related disease.

Most of these claims would arise from the exposure to asbestos by former employees of the SECV. Field Staff were exposed to asbestos within metering enclosures, sub-station buildings containing asbestos, and underground asbestos conduits. The liability for asbestos claims transferred to the businesses formed from disaggregation of the SECV in 1994. The transfer of responsibility was given legal status by various allocation statements which were prepared at the time by the State Government. On one interpretation of the first allocation statement, UED remains liable for future claims by former SECV employees who operated in what is now UED's licensed geographic area, and who were involved in the "distribution and retailing of electricity".

The liability of United Energy for claims resulting from employees of predecessor entities (which include the SECV and the former Gas & Fuel Corporation) does not appear to be contingent upon whether or not the workers transferred employment to UED. In 2004, a dispute arose between the residual SECV and United Energy over precisely this matter. A claim had been brought about by a former SECV worker who was employed from 1970 to 1992, predominantly as a linesman. UED settled the claim so as to avoid protracted legal argument over the interpretation of the allocation settlements. The amount paid to the claimant was $250,000, though a contribution of $60,000 was eventually received by Amaca Pty Ltd (James Hardie). The total out-going from UED was therefore $190,000. The State of Victoria settled directly with the plaintiff for $300,000 inclusive of costs.

Trowbridge Deloitte was engaged by UED in 2005 to assess possible future asbestos liabilities. Trowbridge undertook a full risk quantification which is reported in Trowbridge (2005). The consultants estimated that there would be five future mesothelioma cases in aggregate. Of these:

- Three projected future mesothelioma cases would relate to employees of the SECV only. These were predicted to occur over a 30 year period.
- There would be one projected future mesothelioma case arising from an employee who had worked for both the SECV and UED; and

- There would be one projected future mesothelioma case in respect of an employee who had only worked for UED. On account of the average latency period of these claims, it could take in excess of thirty years before a claim emerged.

Trowbridge (2005) also reported that UED could be required to make payments in relation to "backdated" incidents which may previously have been reported to the SECV, and wjocj would become relevant to United Energy depending upon the based on the outcome of the Drummond case. Trowbridge estimated that there could be up to five such incidents.

Aon has taken account of the Trowbridge study in deriving an appropriate self-insurance premium (of $24,000 per annum) for future asbestos liabilities. The approach taken by Aon is described fully (Aon, 2009k). The analysis undertaken by Aon has also been fully vetted by an in-house actuary, however Aon did not scrutinise in detail the methods, assmptions and data employed by Trowbridge. This is because the Trowbridge study was undertaken several years earlier, and the results of the review had already been accepted by the United Energy Board.

External insurance may be available to cover potential future asbestos liabilities but doubts exist in relation to the extent of coverage. This is because the events giving rise to the claims are likely to have occurred in the distant past. As previously noted, three of the projected future mesothelioma cases are expected to relate to employees of the SECV only.

UED may be afforded a degree of protection by the workers' compensation scheme in operation in Victoria. All employers in Victoria paying a rateable remuneration above $7,500 per annum are required to subscribe to a Work Safe injury policy. Compulsory workplace insurance has been in place since the passage of the Occupational Health and Safety Act, 1985.

UED was unable to rely on a workers' compensation scheme when it sought a resolution to the Drummond matter. The State of Victoria had a Pay As You Go (PAYG) insurance policy in place for most of the period during which Drummond was employed. United Energy inherited the scheme via the allocation statements. Under the policy, United Energy was obliged to reimburse any payments made by its insurers, and to also pay a "management fee". As such, UED determined that there was little merit in claiming upon the policy when the company was enjoined as a party in the proceedings which Drummond brought against the State Government.

Property risks

The property risks category refers to the material damage to property which either belongs to UED, or for which UED is responsible. UED may have assumed responsibility for the property prior to the incidence of loss, destruction or damage. The damage may result from fire and other natural perils, or may be deliberately inflicted by others through acts of theft and/or vandalism. Losses which are consequential to the interruption or interference caused by property damage are also counted in the property risks category.

Aon has reviewed the recorded loss history for United Energy, and has formulated forward projections taking the history and possible future developments into consideration. The assessed premium for self-insurance is $2,749,640. The methods employed by Aon are documented in Aon (2009k).

The historic losses analysed by AON are tabulated in an attachment to Aon (2009k). UED experienced a large loss in 2004, as a result of a transformer failure and fire at the Dandenong Valley zone sub-station on 26 November 2008. There are also regular and repeated annual losses caused by copper theft, vandalism and third party damage to UED property. The losses which occur with predictable frequency have been tabulated below.

Table 5-14: Estimated annual losses as a result of damage to property owned by UED

Type of loss	Expected number of losses	Amount per loss	Total incurred loss
Underground cable excavations (HV)	20	$7,500	$150,000
Vehicle related damage	360	$7,000	$2,520,000
Telecommunications' service provider	40	$2,000	$80,000
Vandalism	50	$1,000	$50,000
Total cost	**470**		**$2,800,000**
Less: Expected Recoveries (10%)			(280,000)
ANNUAL INCURRED LOSS			**$2,520,000**

Amounts shown in real 2010 terms.

Source: Self Insurance Risk Quantification for United Energy, undertaken by Aon Global Risk Consulting. The losses shown in the table are a component of the assessed self-insurance premium for property risks.

Table 5-14 shows that a major source of loss is damage to UED owned property by motor vehicles. Aon anticipates a continuation of losses caused by collisions between motor vehicles and the physical assets used in electricity distribution, mainly electricity poles.

The calculations performed by Aon in respect of property risks have been scrutinised by an actuary who was part of the project team.

UED is insured for property damage under an industrial special risks policy provided by American International Group (AIG). The policy applies principally to material damage and business interruption, with declared values of $357.814 million and $357 million respectively. The property which is insured under the policy is essentially high value electronic equipment, buildings including fit-outs, and network zone sub-stations with associated switchgear and equipment.

In 2008-09, the value of the insured property was reported to be $356.814 million. This is a comparatively small proportion of United Energy's total asset base, which has been valued for re-instatement purposes at $3.7 billion. Geographically dispersed assets, which are comprised of poles, overhead wires, underground cables, switches, street lights, sub-stations and transformers are largely uninsured.

The policy limit for material damage and business interruption is $100 million. This is a combined single limit for any one loss. Sub-limits of liability also apply in respect of specific categories of material loss or damage and consequential loss. Full details are provided in the industrial special risks insurance renewal report for 2008-09, and a copy of this document will be made available to the AER. The insurance premium paid for 2008-09 was $571,104.

The policy deductibles are set out in the renewal report and can be described as follows:

- For material damage:
  - $25,000 in respect of office contents, for losses resulting from one event against which an indemnity is available; and
  - $500,000 in respect of all other losses resulting from one event against which an indemnity is available.
- For business interruption:
  - Twenty-one days of actual, average daily indemnified losses suffered by the insured, subject to a minimum of $1,000,000.

The policy deductible for material damage has been set at a relatively high level of $0.5 million with the result that UED is exposed to the risk of lower valued losses. The experience to-date suggests that these losses happen with high frequency.

The high deductibles under the industrial special risks policy have been taken into consideration by Aon, in its calculation of the self-insurance allowance. UED determined that it should prudently self-insure against the large numbers of lower valued losses, while Aon quantified the current, non-insured exposure.

Poles and wires risk

Poles and wires risk refers to the losses incurred when there is widespread damage to the distribution network brought about by inclement weather conditions. United Energy's distribution assets are particularly susceptible to storm damage, however other possible sources of damage, such as heat waves, also have a significant impact. Table 5-15 presents summary details of the major storms which have caused interruptions to electricity supply over the period from 1995 to 1998. The figures have been presented for illustrative purposes, so as to convey an impression about the periodicity of storms.

As is apparent from the data, there is generally more than one major storm event per annum, and there is evidence of increasing regularity and severity.

Table 5-15: Summary of major storm events, 1995 - 2008

Date	UE SAIFI total	UE SAIDI total	Cause	Feeder reclose operations	Feeder lockout operations	Total Feeder CB operations
02-Apr-08	0.357	232.3	storm	191	0	191
22-Dec-07	0.018	3.1	storm	2	3	5
20-Dec-07	0.057	5.7	storm	12	20	32
11-Feb-07	0.111	11.9	storm			0
26-Jan-06	0.080	7.3	storm			
03-Feb-05	0.173	34.4	storm	41	47	88
20-Nov-03	0.030	3.2	lightning storm	13	6	19
24-Aug-03	0.040	4.6	wind storm	4	6	10
18-Sep-02	0.036	1.9	storm	6	8	14
16-Sep-02	0.028	3.1	storm	1	6	7

Date	UE SAIFI total	UE SAIDI total	Cause	Feeder reclose operations	Feeder lockout operations	Total Feeder CB operations
02-Sep-02	0.092	9.3	wind storm	16	25	
01-Feb-02	0.073	3.7	lightning storm	12	9	21
16-Mar-01	0.049	5.5	storm	7	5	12
21-Dec-00	0.095	7.5	wind storm	11	13	24
30-Sep-00	0.090	7.8	wind storm	2	9	11
25-Mar-99	0.038	2.6	wind storm	3	9	12
26-Feb-98	0.037	5.5	lightning storm	8	7	15
22-Jan-98	0.035	1.3	lightning storm	0	11	11
12-Jan-98	0.063	7.8	lightning storm	19	15	34
27-Jan-97	0.027	3.9	lightning storm	4	6	10
18-Sep-96	0.054	2.4	wind storm	3	9	12
27-Jan-95	0.000		lightning storm	12	20	32
06-Jan-95	0.000		lightning storm	17	7	24
05-Jan-95	0.000		lightning storm	8	8	16
Averages	**0.062**	**16.7**		**13.0**	**11.1**	**22.7**

Source: Jemena Asset Management. SAIFI and SAIDI prior to 1999 have been estimated based on the impact of feeder faults multiplied by a factor of 1.2 for lower level outages. Crude arithmetic averages have been calculated.

UED has sought but has been unable to obtain suitable insurance cover for major event days which cause damage to network infrastructure and components. Aon was advised of the non-availability of a satisfactory insurance policy and accordingly determined that it would be prudent for UED to self-insure. Aon examined the historical data on the costs of dealing with major events such as heat waves and storms. The costs considered were the abnormal expenses, in other words the outlays not already captured in operating and capital expenditure budgets. The costs were comprised of:

- The additional direct and indirect labour resources deployed. Indirect labour refers to the other personnel involved in managing faults and emergencies, notably supervisors, team leaders, availability officers, project planners, and dispatch and control room staff.
- Supplementary operating and maintenance spending on trucks and vehicles, consumable stock and protective clothing.
- Travel costs.
- The hiring of external contractors at emergency rates.
- Supplementary payments to information system vendors.

An important aspect of dealing with storms and other events is a requirement to reschedule planned maintenance work and network upgrades. The postponement of these activities is itself an important contributor to total costs.

Aon assessed that an appropriate annual allowance for self-insurance would be $541,697. This is a useful provision to retain so as to ensure that UED would have the capacity to deal with an extreme future event, and would be able to marshal the necessary resources in a short time frame.

The proposed self-insurance allowance for major event days does not duplicate existing budgets for capital outlays and operating and maintenance expenditure. The calculation has been undertaken in full knowledge of the enhanced capital spending programme put forward by UED. The self-insurance provision is intended to assist in dealing with substantial deviations in spending from trend.

The methods employed by Aon are explained in Aon (2009k). The numerical assessments and modelling work performed have been subject to actuarial review.

Contaminated land

UED faces significant one-off costs over the forthcoming regulatory period in respect of the measures which need to be taken to remediate contaminated land. There are two tracts of land which suffer from varying degrees of contamination, and these are situated at Surrey Hills and at Cheltenham Road, Keysborough. The contamination has been caused by:

- the transportation, storage & disposal of waste including Polychlorinated Biphenyl (PCB) residue, contaminated soil, asbestos, mercury, pit water from underground sub-stations and solid waste; and
- the operation and maintenance of oil filled equipment, such as transformers.

The contamination can be traced back to the period before 1995, when the SECV was operating the sites in question. Up until the mid-1990s, transformers were often serviced on open ground which meant that oil leakages would seep into the soil. Furthermore, transformers in sub-stations were mounted on earthen bunds, allowing oil spills to penetrate below ground. Jemena Asset Management has estimated the provisions which need to be set aside to address the problems, and these are as reported below:

- Decommissioning of the Surrey Hills zone sub-station in 2010: $120,000.
- Decommissioning of the Cheltenham Road, Keysborough site: $93,000.

The site at Cheltenham road has been used for the storage and servicing of transformers. The environmental provisions are reported by JAM[40], and have been factored into the calculations performed by Aon (and reported in Aon, 2009k). UED expects that both plots of land will be sold subsequent to de-contamination, if test results show that the soil condition is satisfactory.

Another tract of land inherited from the SECV and which, at vesting, was incorporated into the Regulatory Asset Base, is located at 8-14 Railway Parade, Dandenong. The land here is severely contaminated for reasons yet unknown, and there are also high levels of toxins in the groundwater. The suspected sources of contamination are the infill which was used to level the land prior to its acquisition by the SECV, and the activities of long-established

40 **Jemena Asset Management (2008c). United Energy Distribution and Multinet Gas Environmental Provision, 2008. Prepared by Ian Russom, Technical Compliance Manager. 20 March 2008.**

industries located on neighbouring plots. In 2006, solicitors Johnson, Winter and Slattery, ("JWS"), provided legal advice in relation to the options available to UED for claiming damages against the polluter. In brief, JWS concluded that:

> " Identifying potential polluters will be difficult not only in terms of proving that pollution was caused, but also identifying persons who are still living, or companies in existence. Also, given the nature of the businesses described in the report [by Monarc Environmental] , even if individuals and companies can be identified and pursued, the resources available for recovery are likely to be limited."[41]

UED has retained consultants Monarc Environmental to conduct on-going investigations at the site, to monitor pollutant levels, and to advise on strategies for beneficial uses of the land. Monarc undertook its first environmental site assessment in 2006, and has been involved in the development of a Site Environmental Management Plan ("SEMP"). The contamination in the soil includes asbestos, and there are high concentrations of aqueous solvents in the ground water. Monarc has recently a prepared a scheme of options for controlling or tackling the level of pollution on the site. The particular alternatives that are selected will depend upon the results of further investigations into the source of the contaminants. The options have been costed, and have been considered in terms of the legislative framework in Victoria, administered by the Environment Protection Authority. Consideration has also been given to the range of possible development options. The report by Monarc shows the probabilities of various options, which are contingent upon the levels and sources of pollution, and also identifies the various costs. Aon drew upon the Monarc (2009j) report in its appraisal of a reasonable provision for self-insurance that should ideally be set aside by UED.

Aon has calculated that the once only costs of addressing the contamination at Railway Parade are $2.18 million. A self-insurance allowance should be set aside to cover this amount. The method used by Aon to work out the provision is documented in Aon (2009k). In essence, Aon has worked out the most likely cost outcome, drawing upon the risk decision tree provided by Monarc (2009j).

The total self-insurance provision for dealing with the impaired fixed assets is equal to the sum of the respective provisions for Surrey Hills, Cheltenham Road, Keysborough, and Railway Parade, Dandenong. The one-off cost has been assessed to be $2.393 million. The use of this cost as a basis for determining a premium has been endorsed by the in-house actuary who forms part of the Aon project team.

On an annual basis over the next regulatory control period, the amount that would be set aside by a prudent DNSP is $0.479 million. The losses that comprise the $2.393 million figure will be crystallised between 2011 and 2015 because there will be changes to the way in which the plots of land are used, and remediation is a pre-requisite to any change.

No external insurance is available for land that is already known to be contaminated, and UED has not put out a request for quotes via its insurance broker.

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[41] **JWS (2006l). Draft memorandum (68053) to United Energy regarding the available legal options for dealing with contaminated land at 8-14 Railway Parade, Dandenong. Prepared by Johnson Winter & Slattery Lawyers. 15 December 2006.**

Environmental liabilities

In view of the revelation in recent years about the extent of contamination of the land at Railway Parade, Aon has assessed that a self-insurance premium should be placed in reserve so as to provide for the possibility of the discovery of further contaminated sites.

The self-insurance provision for future environmental liabilities has been worked out as an annual amount of $43,806. As with other self-insurance premiums, this value should be set aside on an annual basis in the form of a contingency reserve. In order to derive this result, Aon has taken account of the major land holdings of United Energy, including selected easements and plots of land used for zone sub-stations and other items of infrastructure.

UED has been unable to obtain insurance against environmental liabilities although a request for quotes has been placed through its broker, Marsh Finpro. In order for insurance to become available at a reasonable cost, UED would be required to undertake a major environmental audit of its portfolio of land and buildings. The costs inherent in undertaking such an exercise would be prohibitively expensive.

Insurer default risks and fraud

Aon has drawn upon industry knowledge to estimate prudent self-insurance premiums to cover insurer default risk and fraud. A full explanation of the methods employed is provided in Aon (2009k).

UED is currently contemplating the merits of an insurance policy which would cover risks such as employee theft, depositor's forgery, computer theft and funds transfer frauds. However, no decision has as yet been taken, and no insurance agreements have been prepared. A request for quotes has also not been placed with a broker. Prior to 2003, United Energy Limited had a rolling contract for crime coverage which was provided by the Chubb Insurance Company of Australia. The contract was discontinued subsequent to the restructuring of United Energy, and the commencement of the Operating Services Agreement (OSA) with Alinta Asset Management (now JAM).

There are no other mechanisms in place to cover the risks of fraud and insurer default.

Table 5-16: Forecast self insurance provision

2011	2012	2013	2014	2015	Total $M
3.5	3.5	3.5	3.6	3.6	17.7

Amounts shown in real 2010 terms.

Note: The figures in the table do not incorporate the calculated provisions for contaminated land.

5.5.14 Debt raising costs

The basis for determining debt raising costs is contained in section 9.9.2 of this submission. The debt raising costs proposed by UED are based on a benchmark gearing of 60 per cent of UED's regulatory asset base. The application of 11.8 basis points identified in section 9.9.2 in the PTRM results in the debt raising cost forecast as provided in Table 5-17 below:

Table 5-17: Forecast of debt raising costs

2011	2012	2013	2014	2015	Total $M
1.0	1.06	1.12	1.17	1.20	5.55

Note: These costs are included in "other". Amounts shown in real 2010 terms.

5.5.15 Concluding comments

As explained in section 5.4 (and in the accompanying independent report by KPMG) the forecast costs for each of the operating expenditure categories are derived from prices sourced from the tender process and internal cost forecasts, as appropriate.

The forecast costs are based on activity and work volume assumptions contained in UED's Asset Management Plan, and an internal cost build up. The Asset Management Plan identifies the optimal mix of operating and capital expenditure that ensures delivery of the required level of network service at an efficient overall cost level.

In the case of outsourced functions, efficiency savings have been factored into the expenditure forecasts by virtue of the competitive pressure faced by the winning bidder throughout the competitive tender process conducted by UED.

In the case of in-sourced functions, the forecast costs are based on providing more services within the business in order to make efficiency savings overall.

5.6 Benchmarking total operating expenditure forecasts and historical analysis

Benchmarking analysis relating to UED's operating expenditure is presented in section 2.2. As noted in that section, a comparison of UED's operating expenditure performance with that of its Australian peers indicates that UED is an efficient performer.

UED is forecasting an increase in total operating expenditure compared to historic levels. In broad terms, the forecast increase in operating expenditure reflects the projected increases in the volume of work proposed by UED in its asset management plan. The table below provides a comparison of forecast and actual operating expenditure for the current and forthcoming regulatory periods.

Table 5-18: Comparison of forecast and actual operating expenditure[42]

	2006-10 Actual $M	2011-15 Forecast $M	Explanation of variation
MAINTENANCE			

[42] **Actual expenditure for 2006 – 2010 has been restated within categories to be consistent with the forecast methodology where possible**

	2006-10 Actual $M	2011-15 Forecast $M	Explanation of variation
Routine	34.8	36.7	Comparison should be made at the total maintenance line rather than individual – see below
Condition based	50.3	53.0	Comparison should be made at the total maintenance line rather than individual – see below
Emergency based	27.9	29.3	Comparison should be made at the total maintenance line rather than individual – see below
Other maintenance	0.0	0.0	Not applicable
Sub-total maintenance	**113.0**	**119.0**	$10.7m - increased activity and step changes as per appendix offset by efficiencies of new business model.
OTHER FUNCTIONS			
Network operating	119.8	160.8	$21.3m - increased activity and step changes as per appendix. Increased costs previously not passed through due to fixed price contract offset by efficiencies of new business model
SCADA/Network control	27.8	29.2	Not applicable
Billing & revenue	7.5	10.0	$0.9m - increased activity and step changes as per appendix. Increased costs previously not passed through due to fixed price contract offset by efficiencies of new business model. This category should be combined with customer service.
Customer service	30.4	40.8	$1.8m - increased activity and step changes as per appendix. Increased costs previously not passed through due to fixed price contract offset by efficiencies of new business model. This category should be combined with billing & revenue.
Advertising	3.2	4.3	Additional marketing activities to establish UED as a stand-alone distributor.
Regulatory	7.8	10.5	$3.5m - increased activity and step changes as per appendix. Increased costs previously not passed through due to fixed price contract offset by efficiencies of new business model.
Self insurance	0.0	17.7	No value attributed to self insurance in statutory account
Debt raising	0.0	5.6	Previously include as an interest expense
Other	151.8	203.8	Increased costs previously not passed through due to fixed price contract offset by efficiencies of new business model.
Sub-total other functions	**348.3**	**482.9**	

	2006-10 Actual $M	2011-15 Forecast $M	Explanation of variation
Total operating expenditure	**461.3**	**601.8**	

Amounts shown in real 2010 terms.

6. Forecast Capital Expenditure

Key messages

- UED's capital expenditure forecasts have been developed in accordance with the requirements of the Rules and the RIN.
- UED's capital expenditure forecasts are a combination of outcomes from a rigorous, competitive tender process as well as internally based forecasts.
- KPMG has reviewed and endorsed UED's forecasting methodology, providing independent assurance that UED's capital expenditure forecasting methodology complies with the requirements of the Rules.
- In August 2009, UED commissioned Parsons Brinckerhoff ("PB") to review its planning processes. PB found that UED has a sound and comprehensive planning methodology that balances price, quality, reliability and security of supply objectives.
- In recent years, 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. UED's network utilisation is currently at, or slightly higher than, optimal levels. This higher utilization and a revised (increased) estimate of the value of customer reliability is driving a number of major augmentations in the forthcoming regulatory period.
- New zone substations are required over the next seven years to meet demand growth and to improve the reliability of the primary distribution system. Strategic planning studies have identified the location of these new zone substation sites. A number of power line corridors to enable connection of new zone substation and/or improve the security of the sub transmission system have also been identified in these studies.
- 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. This increase in replacement expenditure requirements reflects the age profile of the asset population, with many assets installed in the early 1960s now approaching the end of their expected lives.
- Considerations of prudent safety and environmental impact management require that UED accelerates the replacement of neutral screen services. The installation of additional ground fault neutralisers in bushfire areas and harmonic fitters is also required.
- UED will in-source its control room function as part of its business model transformation. To achieve best-practice, asset management functions and network operational central control should be co-located.
- UED obtained expert advice form Deloitte to develop a robust IT strategy for the forthcoming regulatory period and beyond. Deloitte's report, which has been accepted by UED, recommends a significant increase in capital expenditure to deal

Key messages

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.

6.1 Regulatory requirements and chapter structure

The regulatory requirements in relation to capital expenditure forecasts are similar to those relating to operating expenditure as described in section 5.2 of this submission. In particular, clause 6.5.7(a) of the Rules requires UED's Regulatory Proposal to include a capital expenditure forecast for the forthcoming regulatory control period that will achieve each of the following objectives:

- meet the expected demand for standard control services over that period;
- comply with all applicable regulatory obligations associated with the provision of standard control services;
- maintain the quality, reliability and security of supply of standard control services; and
- maintain the reliability, safety and security of the distribution system through the supply of standard control services.

UED is similarly required to address the requirements of the RIN and the cost allocation methodology in presenting its capital expenditure forecasts.

Schedule S6.1.1 contains a list of information that must be provided to explain and substantiate the forecast of required capital expenditure including the method used for developing the forecast and a certification of the reasonableness of the key assumptions by UED's directors.

Under clause 6.5.7(c) of the Rules, the AER must accept the forecast of required capital expenditure that is included in the revenue proposal if the AER is satisfied that the total of the forecast expenditure for the regulatory control period reasonably reflects the following criteria:

- the efficient costs of achieving the capital expenditure objectives;
- the costs that a prudent operator in the circumstances of the relevant distribution company would require to achieve the capital expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

UED's forecast capital expenditure for the forthcoming regulatory period has been developed to ensure that the above objectives and regulatory requirements are satisfied.

The capital expenditure forecast is derived from UED's Asset Management Plan (and the associated The Future Demand Plan). Those key documents set out plans to deliver:

- the efficient management of the life cycle of the distribution network as a whole and of each asset class that comprises the network in the light of changes in the constraints that are faced by the business throughout that life cycle; and

the capital expenditure required to ensure that forecast new connections and demand growth are met.

As noted in relation to operating expenditure, the remainder of this Chapter also contains additional information that, whilst not required by the Rules, is intended to assist the AER in its assessment of UED's capital expenditure forecasts.

The remainder of this chapter is structured as follows:

- Section 6.2 describes UED's capital expenditure categories in accordance with the RIN, and provides an overview of the capital expenditure forecasts by category for each year of the forthcoming regulatory period.
- Section 6.3 explains UED's capital expenditure forecasting method and key assumptions.
- Section 6.4 presents summary information on UED's forecasts of maximum demand, energy and customer numbers. This information is relevant to the derivation of UED's capital expenditure forecast.
- Sections 6.5 to 6.11 explain UED's expenditure forecasts for each capital expenditure category.
- Section 6.12 examines the differences between forecast and historic capital expenditure, and provides further explanatory information where these differences are material.

6.2 Capital expenditure categories and overview of expenditure forecasts

Schedule S6.1.1 of the Rules sets out the minimum information requirements that a building block proposal must contain in relation to capital expenditure. Schedule S6.1.1 includes the following requirements regarding the choice of capital expenditure categories:

> " A building block proposal must contain at least the following information and matters relating to capital expenditure:
>
> (1) a forecast of the required capital expenditure that complies with the requirements of clause 6.5.7 of the Rules and identifies the forecast capital expenditure by reference to well accepted categories such as:
>
> (i) asset class (e.g. distribution lines, substations etc); or
>
> (ii) category driver (e.g. regulatory obligation or requirement, replacement, reliability, net market benefit, business support etc),
>
> and identifies, in respect of proposed material assets:
>
> (iii) the location of the proposed asset; and
>
> (iv) the anticipated or known cost of the proposed asset; and
>
> (v) the categories of distribution services which are to be provided by the proposed asset."

In addition to the above Rules requirements, capital expenditure categories for standard control services are defined by the RIN for UED as follows:

(a) reinforcement;

(b) load movement;

(c) reliability and quality maintained;

(d) environmental, safety and legal;

(e) SCADA and network control;

(f) non-network assets—IT;

(g) non-network assets—other;

(h) reliability and quality improved (for current regulatory period) or regulatory obligations or requirements for reliability and quality improved (for forthcoming regulatory period).

It should be noted that UED does not have any capital expenditure in relation to load movement, and therefore this category of expenditure is not relevant to UED.

On the other hand, UED does incur "customer initiated" capital expenditure, which is expenditure driven by new or existing customers.

In light of these observations and the RIN requirements, UED has developed its forecast capital expenditure in accordance with the categories shown in Table 6-1 below. UED's forecasts of capital expenditure for each category for each year of the forthcoming regulatory period are also shown in Table 6-1.

Table 6-1: Categories of forecast capital expenditure and overview of expenditure forecast standard control

	YEAR ENDING 31 DECEMBER					Total
	2011	2012	2013	2014	2015	$M
SYSTEM ASSETS						
Reinforcements	47.2	44.1	48.1	46.7	35.5	221.6
Customer initiated	44.9	44.8	47.2	47.8	47.4	232.1
Reliability & Quality Maintained	62.8	60.2	58.7	52.9	54.1	288.7
Reliability & Quality Improvements	0.0	0.0	0.0	0.0	0.0	0.0
Environmental, Safety & Legal	16.1	9.3	11.4	8.0	7.4	52.2
Sub-total system assets	**171.0**	**158.3**	**165.4**	**155.5**	**144.5**	**794.6**
NON-NETWORK ASSETS						
Non-Network General Assets – IT	29.2	28.3	18.1	15.9	7.1	98.5
SCADA and network control	0.0	0.7	3.9	0.0	0.0	4.6
Non-Network General Assets – Other	2.1	4.7	1.9	2.7	1.8	13.1

	YEAR ENDING 31 DECEMBER					Total
	2011	2012	2013	2014	2015	$M
Sub-total non-network assets	**31.3**	**33.8**	**23.9**	**18.6**	**8.8**	**116.3**
Total capital expenditure	**202.2**	**192.1**	**189.2**	**174.1**	**153.0**	**910.9**
Less – Customer contributions	-23.2	-23.4	-24.9	-26.1	-26.1	-123.8
NET CAPITAL EXPENDITURE	**179.0**	**168.7**	**164.3**	**147.9**	**127.2**	**787.1**

Amounts shown in real 2010 terms.

The forecast capital expenditure is expected to be wholly deliverable. UED believes the capital expenditure program can be realistically undertaken assuming:

- an ability to raise new debt and equity finance based on the proposed WACC. Any reduction in the proposed WACC will challenge that assumption;
- revenue will be generated based on this proposal;
- physical resources will be available through the engagement of best of breed service providers and within the business; and
- management resources will be available to undertake the program through the engagement of best of breed service providers and within the business. The Asset Management Plan and IT Plan have been developed so that the overall program can be delivered whilst allowing the business to meet its service performance targets.

Detailed information that explains the methodology and assumptions applied in the development of these forecasts is set out in the remaining sections of this chapter.

6.3 Forecasting method and key assumptions

6.3.1 Introduction

Clauses S6.1.1(2), (3) and (4) of the Rules require that a building block proposal must contain:

- the method used for developing the capital expenditure forecast;
- the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth; and
- the key assumptions that underlie the capital expenditure forecast.

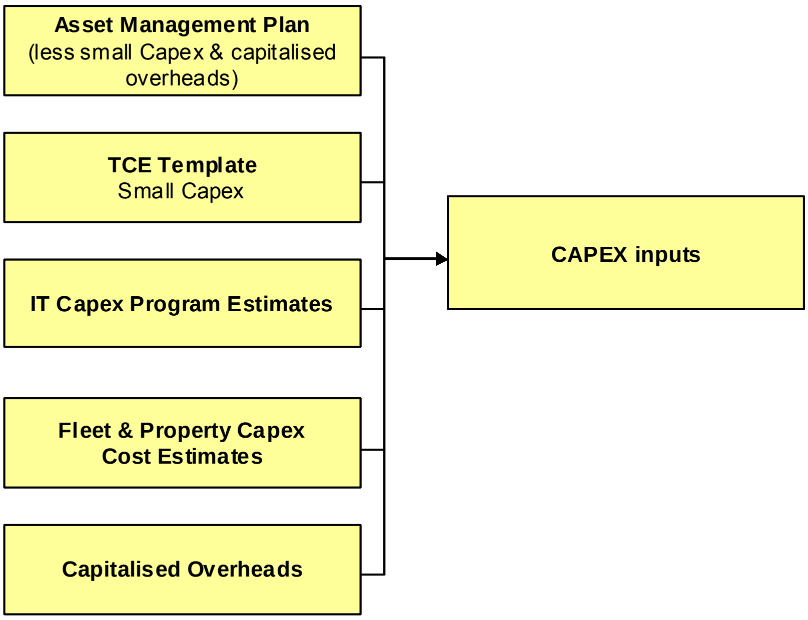
The information presented in this chapter and in sections 3.4 and 5.5 provide an overview of the information that UED is required to provide in accordance with the Rules requirements in clauses 6.5.7(a), (b) and S6.1.1(2), (3) and (4). Detailed information addressing each of these requirements is set out in KPMG's independent report (titled *Forecasting methodology for operating and capital expenditure)* which is included as an appendix to this regulatory proposal.

As already noted in section 5.3, KPMG's independent report confirms that the design and application of UED's forecasting methodology for capital expenditure is consistent with providing expenditure forecasts for the regulatory period that:

- reasonably reflect:
    - the efficient costs of achieving the capital expenditure objectives;
    - the costs that a prudent operator in the circumstances of UED would require to achieve the capital expenditure objectives; and
    - 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.

Figure 6-1 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 6-1: Capital expenditure forecast components



Source: AT Kearney.

Aggregate capital expenditure forecasts are built up from the five components illustrated in the above diagram. These are discussed in further detail below.

6.3.2 Network asset management plan

As previously noted in Chapters 3 and 4, UED’s 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 asset management plan has been compiled by JAM in its capacity as the current outsourced service provider. The plan identifies annually for the calendar years 2011 to 2015, required capital expenditure activity using costs estimated by JAM. These estimates are based on forecasts of customer demand prepared by NIEIR.

UED’s asset management plan includes analysis and information on the following matters that are highly relevant to UED’s capital (and operating) expenditure forecasts:

- legislative requirements, UED’s planning framework and processes;
- growth forecasts, including maximum demand, energy and customer numbers;
- network reliability, causes of network faults; reliability and power quality benchmarking; and target levels of reliability;
- network asset utilisation and losses;
- impact of climate change on network performance and other network risks;
- the generation outlook, including future developments in embedded generation; micro-generation; demand management; and energy efficiency; and
- asset condition and projected weighted-average remaining asset life.

UED’s method for forecasting network capital expenditure relies heavily on the analysis and information contained in the asset management plan to set the strategies for each of the 12 individual components contained in the asset management plan. As noted in section 4.3, UED ensures that its capital budgeting, asset management and investment decisions are robust by:

- producing asset management strategies, plans and budgets that aim to ensure efficient delivery of the required levels of network service and reliability in accordance with stakeholder requirements;
- maintaining and reviewing these strategies, plans and budgets as new information becomes available;
- monitoring and reporting against key performance indicators;
- managing and resolving resource allocation issues;
- ensuring efficient works execution through:
    - efficient construction, maintenance and operation of network assets in accordance with the asset strategies, asset management plan and budget;
    - effective management of programs (such as inspections and vegetation management, among others); and

- o effective capturing, management and diagnosis of asset condition and performance data.

6.3.3 "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 reversing out 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 TCE respondent. TCE Respondent and UED overheads are capitalised in accordance with UED's accounting policy.

6.3.4 Information Technology (IT) capex program estimates

IT capital volumes are based on an IT plan prepared by independent advisors Deloitte. The IT plan forms part of this regulatory proposal and is included as an appendix. Deloitte has provided forecasts of the costs associated with delivery of the plan based on its specialist experience and knowledge. Deloitte has analysed the labour and materials components of these costs.

In accordance with the requirements for this Regulatory Proposal, the IT capital projects were categorised by lifecycle (into three-year, five-year and seven-year categories).

To categorise projects by lifecycle, Deloitte applied the following assumptions to projects, excluding exceptions based on specific project attributes:

- Applications: A five year IT application lifecycle is assumed. Replacement of UED applications is assumed to be required every five years, based on business need and taking into account available support and alternative IT applications.
- Infrastructure: A three year IT application lifecycle is assumed. Replacement of UED infrastructure is assumed to be required every three years where new maintenance and support agreements may be entered into.
- Middleware: A five year IT middleware (i.e. operating systems, databases and integration tools) lifecycle is assumed. Upgrades are considered on a rolling three year basis.

Further principal IT capital expenditure assumptions are set out in the accompanying KPMG report, which is provided as appendix to this Regulatory Proposal.

6.3.5 Fleet and property capex estimates

UED has an existing fleet of 143 vehicles. The AMP outlines a replacement program over the forthcoming regulatory period. This program forms the basis of UED's forecast of fleet capital expenditure.

Property capital expenditure comprises:

- the fit-out of a new control room required under UED's preferred business model which separates the existing network into two sub-networks for operational purposes; and
- a new depot.

6.3.6 Program delivery costs

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. UED's capitalisation policy indicates that:

> " In accordance with the Australian Accounting Standard AASB116 – Property, Plant and Equipment (PPE), the costs of an item of PPE will be recognised as an asset if, and only if:
>
> (a) It is probable that future economic benefits associated with the item will flow to the entity; and
>
> (b) The cost of the item can be measured reliably.
>
> Capital expenditure includes any expenditure that:
>
> * Relates to the purchase, development or construction of a new asset;
>
> * Increases the capacity or functionality of the assets;
>
> * Significantly reduces the ongoing maintenance of the assets; and/or
>
> * Extends the service life of the assets beyond that expected when the assets were originally installed."

It is noted that the definition set out above is consistent with the definition of capital expenditure set out in Electricity Industry Guideline No. 3 "Regulatory Information Requirements", Issue No 6, published by the ESC in December 2006.

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 and comprises:

- network support costs – warehousing and procurement costs;
- network capital expenditure program or project management;
- IT application management;
- IT project services; and
- IT management services.

Each full-time equivalent staff position within UED's internal organisation structure has also been assessed, to determine the percentage of time to be capitalised.

In all cases, the capitalisation percentage rates are assumed to be constant for the entire regulatory period.

The accompanying independent report by KPMG (titled *Forecasting methodology for operating and capital expenditure*, *which is* provided as an appendix) sets out further detailed information regarding capitalisation of overheads.

6.4 UED's forecasts of maximum demand and customer numbers

The table below provides a brief summary of UED's forecasts of maximum demand, energy and customer numbers. These forecasts reflect the expected growth in demand for standard control services over the period (in accordance with the requirements of clause 6.5.7(a)(1) of the Rules), and therefore form key assumptions that underpin UED's capital expenditure forecasts.

Full details of UED's forecasts of maximum demand, energy and customer numbers are set out in chapter 13.

Table 6-2: Forecast maximum demand and customer numbers 2011 - 2015

	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

Full details of UED's forecasts of maximum demand and customer numbers are set out in chapter 13 and the accompanying reports prepared by NIEIR.

6.5 Reinforcement capital expenditure forecast

6.5.1 Overview

Reinforcement capital expenditure represents native growth capital expenditure required to meet growth in demand attributable to existing customers on the network. It consists of expenditure in the following main categories:

- sub-transmission lines;
- zone substations;
- HV distribution feeders;
- distribution substation upgrades; and
- LV feeder augmentation.

The underlying objectives in carrying out reinforcement capital expenditure are:

- to meet regulatory obligations in relation to the maintenance of quality, reliability and security of supply of standard control services;
- to 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
- to facilitate viable embedded generation projects.

Table 6-3 shows the actual reinforcements capital expenditure for the 2006-2010 regulatory period and the reinforcements demand capital expenditure forecast for the forthcoming regulatory period.

Table 6-3: Actual and forecast reinforcements capital expenditure 2006-2010

YEAR ENDING 31 DECEMBER				
2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
44.1	48.1	46.7	47.2	35.5

Amounts shown in real 2010 terms.

6.5.2 Basis for proposed reinforcement capital expenditure

As discussed in Chapter 13, UED adopts a probabilistic approach to planning which tolerates a measured risk of loss of supply in circumstances involving outage of plant items at infrequent times of high network loading. This approach contrasts with one which aims to deterministically ensure that forecast 50 per cent PoE network loadings can be sustained even with one circuit element out of service (so-called “N-1” planning).

A probabilistic approach enables the incremental costs of investment to be balanced against the incremental benefits (in the form of maintained supply reliability), to identify those investments that maximise net value to customers. Implicit in the use of probabilistic planning is the acceptance of a certain degree of risk. Combining probabilistic and contingency planning is likely to provide the best economic outcome for customers.

The application of a probabilistic planning approach has been one of the main factors driving industry-benchmark levels of high utilisation of UED's network distribution system and assets in the current regulatory period and has facilitated the economic deferral of some augmentation projects. In addition, other initiatives such as network power factor improvement, implementation of DMS, reconstruction of over head lines to operate at higher temperature and inter-zone-substation load-transfer schemes have all facilitated the management of optimal maximal asset utilisation.

In August 2009, UED commissioned Parsons Brinckerhoff (“PB”) to review the planning methodology that determines the demand forecast scenario to be used and the types and timing of the demand expenditure. PB investigated capacity planning associated with demand growth and the planning guidelines relating to expenditure required to meet the anticipated demand growth.

Overall PB found that UED has a sound and comprehensive planning methodology that balances price, quality, reliability and security of supply objectives. The planning criteria adopted by UED provide a sound platform to achieve an efficient balance between cost and assessed risks, which in turn leads to the optimum balance between capital expenditure and system performance.

PB also noted that UED uses a 10 per cent POE demand forecast for capacity planning whereas all other Victorian DNSPs use 50 per cent POE demand forecast in their planning process. PB considered UED's use of a 10 per cent POE forecast is appropriate (for flagging potential capacity constraints and in assessing energy at risk) because actual load-at-risk when the demand exceeds forecast can be substantial. The use of 10 per cent POE forecasts will provide adequate lead time to prepare and implement suitable investment and management plans.

In order to determine the "economically-optimum" level of augmentation, it is necessary to place a value on supply reliability from a customer perspective. It is recognised that this value will depend on the customers affected and the duration of any particular outage. It is also recognised that estimating such a value may be inherently difficult. It is common international practice by most utilities to use a composite (or average) marginal value of reliability as an 'a priori' assessment of supply interruption costs, generally referred to as the Value of Customer Reliability ("VCR:). Charles River Associates ("CRA") was commissioned by VENCorp (now AEMO) in September 2008 to estimate VCR using quantitative surveys on the cost impacts of unplanned electricity supply interruptions from a wide cross-section of customers. The CRA study estimated the composite or average value of customer reliability in Victoria for all electricity consumers to be around $47,600 per MWh as at September 2008[43].

UED has historically been using VCR values of $5 per kWh for residential, $10 per kWh for commercial and $15 per kWh for industrial customers. Project benefit assessments now include sensitivity studies with values for VCR derived from residential, commercial, agricultural and industrial sector values given by the latest (2008) CRA report[44] but weighted in accordance with the composition of the customer load. The significant increase in the assumed value of VCR will inevitably lead to an increase in network augmentations.

A further important factor in determining future reinforcement capital expenditure is the existing and projected rate of network utilisation. In recent years, 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. Based on 2009 summer loading, however, UED's network map of distribution substation utilisation is indicating that utilisation in some areas is at, or slightly higher than optimal levels. The map below (Figure 6-2) highlights the need to continue addressing the high utilisation of assets, in particular within the inner urban area.

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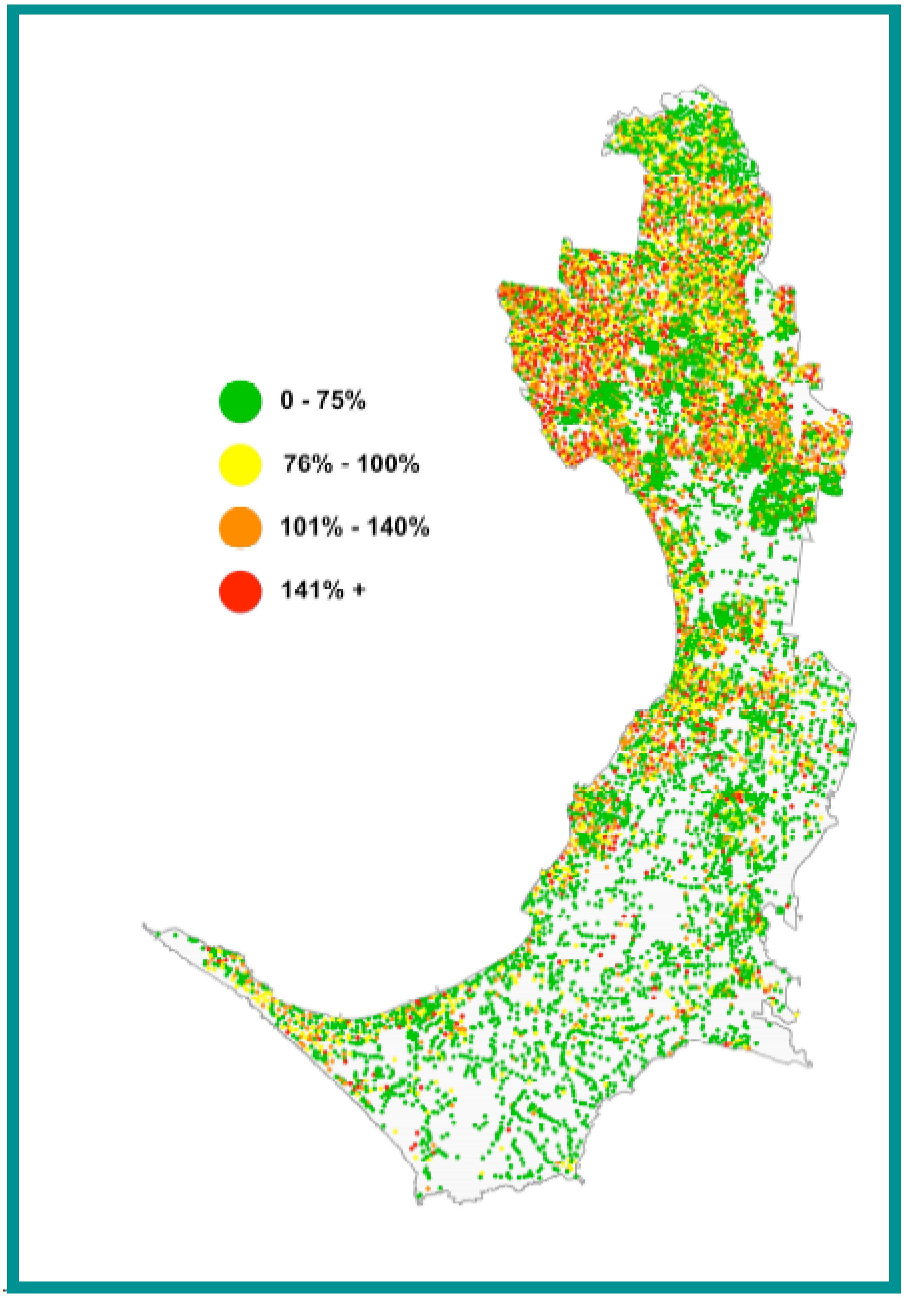
[43] VENCorp (2008). Values of customer reliability used by VENCorp for electricity transmission planning, consultation paper. Victorian Energy Networks Corporation. 5 September 2008.

[44] The most recent information published regarding the estimation of the VCR appeared in the 2009 Victorian Annual Planning Report, which was published in July of this year. Page 113 of that report stated: "Load reduction costs are valued using the Value of Customer Reliability (VCR; $55,000 per MWh, or a sector-specific VCR where appropriate). The VCR level has been escalated following a review completed by NERA in March 2009."

Figure 6-2: Distribution substation loading, Summer 2008



A summary of asset utilisation at distribution feeder level, zone substation and sub-transmission lines is presented below. Utilisation here is defined as the thermal loading of the particular asset at the time of maximum demand expressed as a proportion of its thermal rating or N-1 rating as specified. 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)

In the forthcoming regulatory period, it is anticipated that the Advanced Interval Metering Rollout ("AIMRO"), will provide more detailed raw data about the energy consumption of network customers. Information Systems will be required to translate this data into information that can be used to further improve the planning of the distribution substation and low voltage network. Notwithstanding this potential improvement, UED's planning indicates that a significant increase in reinforcement capital expenditure is now required.

6.5.3 Summary of major reinforcement works

A summary of major augmentation works planned for UED over the period from 2009/10 to 2015/16 is presented below. The works include new zone substations, planned to be established over the next seven years to meet demand growth and to improve the reliability of the primary distribution system. Strategic planning studies have identified the location of these new zone substation sites. A number of power line corridors to enable connection of new zone substation and/or improve the security of the sub transmission system have also been identified in these studies.

UED needs to acquire properties and easements well in advance of construction of network assets to ensure their availability and the certainty of planning approvals. Some of the new zone substation sites will be required in established areas where land may be difficult to procure and in high demand.

Changing community and stakeholder expectations also requires consideration to be given to visual amenity, EMF exposure, perceived reductions in property value and environmental impacts. In consideration of these issues, UED's planning approach will ensure:

- appropriate assessment through continued liaison with local councils and the Department of Infrastructure and Planning;
- early and rigorous community and stakeholder engagement is established to provide transparency and to reinforce the need for and benefits of the proposed zone substation or powerlines; and
- improved processes for site and easement selection to provide more transparency of the need and the reasoning for the selection.

The information presented in dot-point summary below has been extracted from UED's Network AMP that has been prepared in a traditional fiscal year basis and is consistent with UED's financial year. The detailed data contained in the RIN has transposed this data into a calendar year format.

2009/10

- Langwarrin (LWN) zone substation Stage 2 of 2 (construction and commissioning): The new zone substation will help to off-load the highly-loaded FSH zone substation, its 66kV sub-transmission loop and highly-loaded feeders and improve reliability of supply in the area.

- Carrum (CRM) zone substation 3rd 66/22kV transformer Stage 2 of 2 (construction and commissioning): A new 3rd transformer will help to remove the risk of loss of supply at CRM for N-1 contingency events, off-load highly-utilised feeders and improve reliability of supply in the area.

- RBD (Rosebud) zone substation redevelopment Stage 2 of 4: The existing RBD substation is a rural-type station. It is proposed to convert RBD into a fully-switched urban-type zone station over three years 2009, 2010 and 2011 (four financial years 2008/09, 2009/10, 2010/11 and 2011/12). Works for Stage 2 include the replacement of an existing aged, under-rated 10/13.5MVA transformer with a new 20/33MVA transformer and part-replacement of existing 66kV switchgear in 2009/10. This will not increase the station N-1 capacity but will help to increase the station's N rating.

- MR (Moorabbin) zone substation transformation augmentation Stage 2 of 2: With test results indicating that MR Transformer No 3 is ageing at an elevated rate and that its paper insulation had deteriorated to the extent that the transformer is at the end of its service life, it is proposed to install and commission a new transformer at MR prior to summer 2009/10 together with a new 66kV circuit breaker and to replace the existing Transformer No 3 with a new 20/33MVA unit by 30 June 2010.

- BW (Burwood) zone substation Stage 1 of 2: To fully address the issues associated with the noise emanating from the 11/6.6kV auto-transformers and alleviate the risk of overloading 6.6kV feeders BW4 and BW8, it is proposed to convert the BW 6.6kV network to 11kV over three years (financial years 2009/10 and 2010/11).

- TBTS-DMA 66kV loop upgrade: It is proposed to upgrade this critically-loaded loop.

- ERTS-DSH-DVY-ERTS 66kV loop upgrade Stage 1 of 2: With projected growth in the industrial area of Dandenong South, this sub-transmission loop will remain highly-loaded. It is proposed to upgrade this loop. A viable option will be to interconnect ERTS-DSH-DVY-ERTS loop with ERTS-DN-HPK-ERTS loop by establishing a new 66kV line from DN 66kV Bus No 2 to the DSH-DVY line. This has the added benefit of improving the N-1 rating for the critically-loaded ERTS-DN- HPK-ERTS loop which is shared between UED and SPI Ausnet Electricity.

2010/11

- RBD (Rosebud) zone substation redevelopment Stage 3 of 4: Works for Stage 3 involves replacing the remaining 66kV switchgear and completing the 66kV ring bus in 2010/11.

- ERTS-DSH-DVY-ERTS 66kV loop upgrade Stage 2 of 2.

- MTN (Mornington) zone substation redevelopment Stage 1 of 3: MTN is a rural-type station. It is proposed to convert MTN into a fully-switched urban-type zone station over three financial years 2010/11, 2011/12 and 2012/13. In the first stage of the project, planned for 2010/11, it is proposed to establish a 66kV ring bus for MTN. The ring bus has the added benefit of removing the overload risk on the TBTS-MTN-FSH-TBTS sub-transmission loop.

- BW (Burwood) zone substation Stage 2 of 2: convert part 6.6kV to 11kV.
- Surrey Hills (SH) Stage 1 of 3: Convert from 6.6kV to 22kV.
- Dandenong Valley (DVY) zone substation new 20/33MVA transformer Stage 1 of 2. On present forecasts, it is proposed to replace the under-rated 12/20MVA mobile transformer with a standard fully-rated 20/33MVA transformer over two financial years 2010/11 and 2011/12 in order to meet growth in customer demand in the area.
- Clarinda (CDA) 2nd 66/22kV transformer Stage 1 of 2. CDA is a single transformer station. It is proposed to relocate the mobile transformer from DVY and install it at CDA on a permanent basis over two financial years 2010/11 and 2011/12.
- HTS-MR-BT-NB-HTS 66kV loop upgrade Stage 1 of 2: It is proposed to upgrade this loop over two financial years 2010/11 and 2011/12.
- Keysborough (KBH) zone substation. Acquisition of a suitable site.
- Springvale/Springvale West (SV/SVW) zone substation 3rd transformer project Stage 1 of 2: It is proposed to augment either SV or SVW with a 3rd transformer over two financial years 2010/11 and 2011/12 to support growth by major business customers in the area.
- RWTS-BH-NW-RWTS 66kV loop upgrade Stage 1 of 2: It is proposed to upgrade this loop over two financial years 2010/11 and 2011/12.

2011/12

- RBD (Rosebud) zone substation redevelopment Stage 4 of 4: Works for Stage 4 involve replacing the remaining transformers with a new 20/33MVA transformer.
- MTN (Mornington) zone substation redevelopment Stage 2 of 3: In the second stage, planned for 2011/12, it is proposed to establish a new indoor 22kV switch-room with two 22kV busbars, bus-tie CBs and transformer CBs and retire the aged plant at the site.
- Dandenong Valley (DVY) zone substation new 20/33MVA transformer Stage 2 of 2.
- Clarinda (CDA) 2nd 66/22kV transformer (relocate the mobile transformer from DVY to CDA on a permanent basis) Stage 2 of 2.
- Surrey Hills (SH) Stage 2 of 3. Convert from 6.6kV to 22kV.
- HTS-MR-BT-NB-HTS 66kV loop upgrade Stage 2 of 2.
- Keysborough (KBH) zone substation Stage 1 of 3 of design, construction and commissioning.
- MTS-CFD-EL-EM-MTS 66kV loop upgrade Stage 1 of 2: It is proposed to upgrade this loop by establishing a 3rd leg from MTS to EL-EM line.
- Springvale/Springvale West (SV/SVW) zone substation 3rd transformer project Stage 2 of 2: It is proposed to augment either SV or SVW with a 3rd transformer over two

financial years 2010/11 and 2011/12 to support growth by major business customers in the area.

- Lyndale (LD) zone substation 3rd transformer project Stage 1 of 2: It is proposed to augment LD with a 3rd transformer over two financial years 2011/12 and 2012/13.
- Mentone (M) zone substation 3rd transformer project Stage 1 of 2: It is proposed to augment M with a 3rd transformer over two financial years 2011/12 and 2012/13.
- New Templestowe zone substation. Acquisition of a suitable site.
- RWTS-BH-NW-RWTS 66kV loop upgrade Stage 2 of 2.

2012/13

- MTN (Mornington) zone substation redevelopment Stage 3 of 3: In the third stage, it is proposed to establish replace the existing aged 10MVA transformers with a new 20/33MVA unit and convert the station into a fully-switched zone substation.
- Surrey Hills (SH) Stage 3 of 3: Convert from 6.6kV to 22kV.
- Keysborough (KBH) zone substation Stage 2 of 3 of design, construction and commissioning.
- MTS-CFD-EL-EM-MTS 66kV loop upgrade Stage 2 of 2: It is proposed to upgrade this loop by establishing a 3rd leg from MTS to EL-EM line.
- TBTS-RBD line Stage 1 of 4: it is proposed to establish a 3rd line from TBTS to RBD over four financial years 2012/13 and 2015/16.
- Lyndale (LD) zone substation 3rd transformer project Stage 2 of 2.
- Mentone (M) zone substation 3rd transformer project Stage 2 of 2.
- Langwarrin (LWN) zone substation 2nd transformer project Stage 1 of 2: It is proposed to augment LWN with a 2nd transformer over two financial years 2012/13 and 2013/14.
- Burwood (BW) zone substation Stage 1 of 3: Convert to a fully-switched 66/11kV station over three financial years 2012/13, 2013/14 and 2014/15.
- RTS-K 66kV line upgrade Stage 1 of 2.

2013/14

- Keysborough (KBH) zone substation Stage 3 of 3: Design, construction and commissioning.
- Langwarrin (LWN) zone substation 2nd transformer project Stage 2 of 2.
- Box Hill (BH) zone substation 3rd transformer project Stage 1 of 2: It is proposed to augment BH with a 3rd transformer over two financial years 2013/14 and 2014/15.
- New Templestowe zone substation Stage 1 of 2: Design, construction and commissioning.
- TBTS-RBD line Stage 2 of 4: It is proposed to establish a 3rd line from TBTS to RBD over four financial years 2012/13 and 2015/16.

- Burwood (BW) zone substation Stage 2 of 3.
- RTS-K 66kV line upgrade Stage 2 of 2.

2014/15

- Templestowe (TSE) zone substation Stage 2 of 2: Design, construction and commissioning.
- Box Hill (BH) zone substation 3rd transformer project Stage 2 of 2.
- Notting Hill (NO) zone substation 3rd transformer project Stage 1 of 2: It is proposed to augment NO with a 3rd transformer over two financial years 2014/15 and 2015/16.
- Dromana (DMA) zone substation 2nd transformer project Stage 1 of 2: It is proposed to augment DMA with a 2nd transformer over two financial years 2014/15 and 2015/16.
- TBTS-RBD line Stage 3 of 4: It is proposed to establish a 3rd line from TBTS to RBD over four financial years 2012/13 and 2015/16.
- Burwood (BW) zone substation Stage 3 of 3.
- West Doncaster (WD) 6.6kV conversion Stage 1 of 2: Convert 6.6kV network to 11kV.
- SVTS-NP-SS-SVTS 66kV loop upgrade Stage 1 of 2.

2015/16

- Notting Hill (NO) zone substation 3rd transformer project Stage 2 of 2.
- Dromana (DMA) zone substation 2nd transformer project Stage 2 of 2:
- TBTS-RBD line Stage 4 of 4: It is proposed to establish a 3rd line from TBTS to RBD over four financial years 2012/13 and 2015/16.
- Frankston (FTN) zone substation 3rd transformer project Stage 1 of 2: It is proposed to augment FTN with a 3rd transformer over two financial years 2015/16 and 2016/17.
- Scoresby (SCY) zone substation: Acquisition of a suitable site.
- West Doncaster (WD) 6.6kV conversion Stage 2 of 2.
- SVTS-NP-SS-SVTS 66kV loop upgrade Stage 2 of 2.
- ERTS-LD-MGE-ERTS 66kV 3rd leg Stage 1 of 2.

6.5.4 Trend analysis: reinforcement capital expenditure

Compared with the current period's actual level of expenditure, a significant increase in reinforcement expenditure over the forthcoming regulatory period is projected. The increase in reinforcement expenditure for the forthcoming regulatory period, compared with current period, reflects the higher assumed value of VCR and the relatively high present level of asset utilisation.

6.6 Customer initiated capital expenditure

6.6.1 Overview

Capital expenditure required to meet the needs of new customers and the increased needs of existing customer is referred to as Customer Initiated Capital ("CIC").

UED further categorises CIC capital expenditure into the following categories:

- business supply projects;
- urban multiple-occupancy supply;
- urban residential supply;
- customer servicing;
- recoverable works; and
- rural supply

Table 6-5 below shows the actual CIC expenditure for the 2006-2010 regulatory period and the benchmark expenditure for the 2011-2016 regulatory period.

Table 6-5: Actual and projected customer initiated capital expenditure 2006 - 2016

	YEAR ENDING 31 DECEMBER				
	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Forecast	44.9	44.8	47.2	47.8	47.4

Amounts shown in real 2010 terms.

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, where the projects have not yet been identified.

Figure 6-3: Indicative customer capital model over time

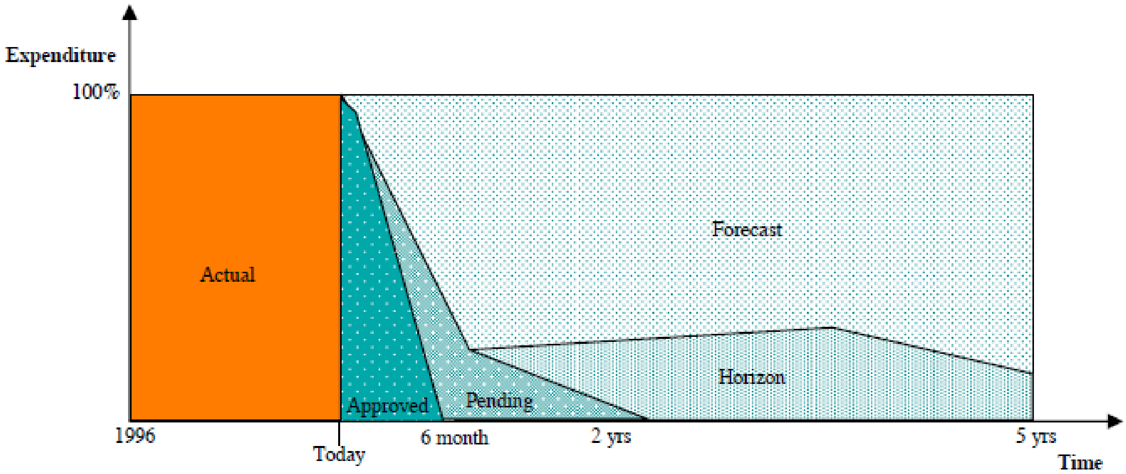


Figure 6-3 above provides a schematic representation of the five different categories of project.

6.6.2 Basis for proposed customer-initiated capital expenditure

For actual projects, historical records are stored and used to derive the necessary statistical data for predicting projects in the future. This detail includes:

- number of projects initiated per month;
- average cost of projects initiated per year;
- expenditure profiles for projects and;
- historical trends that are used to verify the forecast growth of the project numbers and the average cost per project.

For approved projects, works are individually forecast per month at the project level by the project manager. These works are generally forecast over the 0->6 month period. These projects have minimal scope for variations in expenditure.

For pending projects, capital expenditure depends on the probability that customers accept UED offers, rather than choosing not to proceed or defer works.

Forecast and horizon projects are more difficult to forecast accurately. Horizon projects are typically significant in size and therefore the accuracy of these forecasts can materially affect the overall accuracy of the CIC forecast. UED is aware of a number of prospective data centre projects in the UED service area which have the capacity to almost double the CIC expenditure should they proceed. UED budgets for these projects on the basis of total project cost and the probability of the project proceeding. As further details are made available about these large projects from developers, the forecasting accuracy is increased and budgets revised.

In addition to examining each of the five components of CIC projects, UED examines various indices that may be correlated with CIC expenditure requirements. These indices include council roadwork plans and construction forecasts.

6.6.3 Trend analysis: customer-initiated capital expenditure

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. As a result of the Eastlink project, UED is experiencing localised growth around the freeway exit points, but this growth is not expected to be sufficiently large to replace the Eastlink Project. As noted above, several data centre projects could occur during this regulatory period and therefore it is appropriate to include an allowance for at least one such project.

6.7 Reliability and quality maintained

6.7.1 Overview

This category relates to expenditure required to maintain the reliability and quality of the network in order to meet the reliability targets established by the STPIS. The category consists of the replacement of assets. Replacement of assets is undertaken for the following reasons:

- Preventative (pro-active): assets are replaced prior to failure in accordance with life-cycle asset management strategies. For example, asset types showing high than normal failure rate trends may lead to 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 cycles established for each asset class. Asset will be replaced after inspection if they meet pre-determined replacement criteria established for that asset class.

Table 6-6 below shows the actual Reliability and Quality Maintained capital expenditure for the 2006-2010 regulatory period and the benchmark expenditure for the 2011-2016 regulatory period.

Table 6-6: Reliability and quality maintained capital expenditure, 2006 - 2010

	YEAR ENDING 31 DECEMBER				
	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Forecast	62.8	60.2	58.7	52.9	54.1

Amounts shown in real 2010 terms.

6.7.2 Basis for proposed reliability and quality maintained capital expenditure

UED has developed a balanced approach to maintenance and asset replacement strategies, making substantial investments to arrest asset deterioration and to improve service reliability. These customer-focused initiatives have shifted the emphasis from reactive (responding to failure) to pro-active (both preventative, condition-based and time-based) expenditure with a view to achieving long-term cost minimisation.

Replacement asset management uses methods that determine replacement on a "just in time" basis. Failure to undertake sufficient preventive replacement will cause the network average age and hence the component failure rate, to increase to a point where the replacement balance is restored at higher annual cost. Sufficient replacement expenditure needs to be undertaken to control the network failures consistent with a stable average network age (or percentage remaining life).

In order to maintain network "life" this plan identifies replacement expenditure increasing over time consistent with the network age profile that showed large growth in the 1960's and 1970's. An increase in replacement expenditure is needed now to ensure the network does not age further with a consequential increase in component failures and ensures that asset replacement expenditure does not subsequently dramatically step up in the medium term. It is noteworthy that a typical network has a total average asset life is 51.8 years. For UED this means that any replacement expenditure less than about $55M per year will result in long-term ageing of the network.

UED is currently renewing assets at a rate that is allowing the average asset age of the network to increase. This is manifesting as an increasing number of asset-failure-related faults. The increase in asset faults is being offset by the investment in reliability improvement programs and this should maintain average network reliability in the face of an increasingly aged and failure prone asset base.

UED has engaged the services of PB Power to develop a model to test its in-house forecast of non-load-related capital expenditure. The model includes:

- a listing of network asset classes by voltage and asset type;
- replacement profiles for each asset class along with remaining asset life curves; and
- asset condition assessment so that asset age profiles can be adjusted to reflect their actual condition.

The asset condition assessment provides an opinion as to whether the assets will actually remain in service for a longer or shorter period than the asset life assigned. Assessment of "Good" or "Poor" is given to indicate a longer or shorter than average life.

The PB Power model outputs are determined by age and condition-based assessments of assets and therefore do not cater for replacement driven by external causes such as lightning strikes, car incidents, vandalism or work required due to SPI Powernet (transmission) projects. Specific risk-based programs such as pole fire mitigation projects or spares inventory increases have been forecast utilising internal asset management techniques and trending based on historical activity.

6.7.3 Trend analysis: reliability & quality maintained

The overall quantity of asset failures in the period 1999 to 2008 indicates an increasing trend of approximately 2 per cent per annum. Preventative maintenance and replacement aims at minimising asset based failures which could very quickly impact reliability of supply should the failure affect large numbers of customers.

UED is entering a period in which the requirement for asset replacement expenditure will substantially increase. This increase in replacement expenditure requirements reflects the age profile of the asset population, the large proportion of the assets installed beginning in the early 1960s, and the fact than many of the assets installed at that time are approaching the end of their expected lives. The increase in expenditure is therefore required to ensure that the network age and condition is not permitted to deteriorate to the extent that there is an increased risk of asset based failures, and a subsequent risk to network reliability over the medium term.

6.8 Environmental, safety and legal

6.8.1 Overview

The drivers for environmental management are:

- 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.

Table 6-7 below shows the actual environmental safety & legal capital expenditure for the 2006-2010 regulatory period and the benchmark expenditure for the 2011-2016 regulatory period.

Table 6-7: Environmental, safety and legal capital expenditure, 2006 - 2010

	YEAR ENDING 31 DECEMBER				
	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Forecast	9.3	11.4	8.0	7.4	52.2

Amounts shown in real 2010 terms.

6.8.2 Basis for proposed environmental, safety and legal capital expenditure

Adverse environmental impact is mitigated by ensuring that construction programs take account of that impact. A range of environmental management programs are adopted and reflected through all aspects of the business including construction, operation and maintenance activities.

Environmental programs having environmental benefits directly related to the assets are summarised below:

- Electrical Equipment Containing Polychlorinated Biphenyls (PCBs): Items of electrical equipment such as reactors or low voltage capacitors, and transformers, have been identified with low levels of PCBs contamination. As these items are identified they are scheduled for removal or replacement.
- Oil-Filled Electrical Equipment: Specific bunding projects in order to prevent contamination in the event of a leaking transformer.
- Asbestos: Implementing corrective actions when identified.
- Noise Abatement: The main source of noise complaints are from customers near electrical substations. Transformers within substations emit a low, continuous humming noise. Many substations are located in residential areas and even quite low noises can be disturbing to neighbours. UED has included noise as one of the determining criteria when selecting sites for new substations, purchasing new transformers, and designs new substations to comply with EPA noise emission requirements.

6.8.3 Trend analysis: Environmental, safety and legal capital expenditure

The trend in the forthcoming regulatory period is for an increasing spend profile in this category. This is largely due to two major programs of work as detailed in the AMP:

- The replacement of neutral-screened overhead services. UED has a significant population of this type of service cable that runs from the pole attachment to the connection on the customer's building. 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. 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
- 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.

6.9 SCADA and network control

6.9.1 Overview

This category includes the cost of maintaining the equipment required to operate UED's control room. This category also includes any modification or relocation costs of the control room. (Note: all SCADA-related expenditure is included in the IT program.)

Table 6-8 below shows the actual SCADA and network control capital expenditure for the 2006-2010 regulatory period and the benchmark expenditure for the 2011-2016 regulatory period.

Table 6-8: SCADA and network control capital expenditure, 2006 - 2010

	YEAR ENDING 31 DECEMBER				
	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Forecast	0.0	0.7	3.9	0.0	0.0

Amounts shown in real 2010 terms.

6.9.2 Basis for proposed SCADA and network control

The amount included in the forecast is for the relocation of the control room. Currently UED's control room functions are managed by JAM. UED has determined, from its 7/11 project, that the control room will be ultimately in-sourced during this regulatory period. Therefore UED has a requirement to establish a control room specifically dedicated to mange the UED network. 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.

6.10 Non-network assets - IT

6.10.1 Overview

Low levels of IT expenditure over the past years 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 have developed this IT capital program to address these risks. The program sets out a roadmap that lays the foundation for an effective and efficient IT capability aligned to UED's business needs. The program excludes the IT investments that are part of the Advanced Metering Infrastructure (AMI) program.

The projects included in the IT capital program have been identified by assessing UED's strategic objectives and the IT application and infrastructure capabilities required to support these objectives. The assessment included a review of the current IT capital program and estimation of the required capital expenditure for the projects and the program. IT capability gaps that were identified have been defined as additionally required projects and added to the IT capital program.

Deloitte has prepared UED's IT capital strategy and program for the 2011 – 2015 period. This has been endorsed by management and the UED board as a prudent forecast of IT requirements. The IT plan is attached as an appendix.

Table 6-9 and Table 6-10 below show the actual IT capital expenditure for the 2006-2010 regulatory period and the forecast expenditure for the 2011-2016 regulatory period.

Table 6-9: IT capital expenditure, 2006 - 2010

	YEAR ENDING 31 DECEMBER				
	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Forecast	29.2	28.3	18.1	15.9	7.1

Amounts shown in real 2010 terms.

Table 6-10: Reconciliation of 2006 – 2010 period ($000's)

	Description	06-10 EDPR Sub	06-10 Actual Spend	Diff	Rationale for Difference
Manage Stakeholders	Technologies that allow UED to present information to end users, e.g. portal technologies, emergency management	400	350	-50	Not material
Manage Network	Technologies that allow UED to manage the electricity network, e.g. SCADA, DMS/OMS systems	546	6,623	6,077	DMS Hardware and Software Implementation during period caused an increase in Network spending
Manage Assets	Technologies that allow UED to manage asset and capital works programs to ensure the electricity network maintained, e.g. Asset Management, GIS systems	1,697	2,041	344	Not material
Manage Metering and Revenue	Technologies that allow UED to manage the metering and revenue processes inc all electricity market interfacing, e.g. CIS, Billing systems	12,350	4,157	-8,193	EDPR Submission accounted for Advanced Metering implementation. This implementation was moved as part of the Victorian government's AMI Program
Manage Business	Technologies that support all other UED's corporate operations, e.g. Treasury, HR, Audit and Risk systems	13,456	3,597	-9,859	Business developed applications continued to meet requirements without impacting performance so rationalisation and consolidation was delayed in this period
Manage IT	Supporting IT capabilities including software and hardware that enable the other functional areas to operate, e.g. Servers, Storage, Facilities, Networks	24,386	10,116	-14,270	IT hardware and software lifecycle processes were extended. Instability in vendor products (e.g. Microsoft Vista) delayed replacement projects

	Description	06-10 EDPR Sub	06-10 Actual Spend	Diff	Rationale for Difference
Total		52,835	26,883	-25,952	

Amounts shown in real 2010 terms.

Table 6-11 provides a detailed explanation of variances between actual expenditure in the current period to forecast expenditure in the next regulatory period.

Table 6-11: Comparison of 2011-2015 forecasts to 2006-2010 actual expenditure

Capability Area	06 - 10 Actual Spend	11 - 15 EDPR Subm'n	Difference	Rationale for Difference
Manage Stakeholders	350	8,684	8,334	An increasing focus on managing customers and suppliers is the main difference for the difference in the Manage Stakeholders capability area
Manage Network	6,623	15,153	8,530	Replacement of SCADA and a lifecycle upgrade of DMS is the main reason for the difference in the Manage Network capability area
Manage Assets	2,041	34,081	32,040	Lifecycle upgrade of SAP for all Corporate functions is the main reason for the difference in the Manage Assets capability area
Manage Metering and Revenue	4,157	8,466	4,310	Replacement of the applications and infrastructure supporting Type 1 - 4, UMS and Type 7 meters is the main reason for the difference in the Manage Metering and Revenue capability area
Manage Business	10,958	7,361	7,225	System rationalisation, lifecycle upgrades to the reporting systems and an implementation of new capabilities are the key reasons for the difference in the Manage Business capability area
Manage IT	10,116	21,158	11,042	Upgrades to DC facilities, Infrastructure, Middleware and Desktop operating systems are the key reasons for the difference in the Manage IT capability area
Total	**26,883**	**98,500**	**71,617**	**Main drivers for the difference in regulatory periods are the lifecycle replacements of DMS, SAP, SCADA and the DR data centre upgrade.**

Amounts shown in real 2010 terms.

6.10.2 Basis for proposed IT capital expenditure

The UED capital expenditure over the Electricity Distribution Pricing Review (EDPR) submission period 2011 to 2015 is estimated at $98.6 million. This is a significant increase in IT capital expenditure over the previous period for a number of reasons:

1. IT systems are "end of life" and therefore require significant cost to maintain and manage.
2. IT systems have a normal operating life between 5 and 7 years. Therefore, the replacement of major functionality and capability within this program is part of a normal lifecycle process (refer to 2001 - 2005 submission; capex for the period 2000 – 2004 was ~$65m plus a further ~$20m for 1999).
3. Business requirement for IT systems to support multiple contracts.
4. Business requirement for IT systems to meet changing regulatory obligations.
5. Business requirement for IT systems to manage increasing data.
6. Business requirement for IT systems to manage increasing customer expectations.
7. Business requirement for IT systems to achieve the efficiencies forecast in the operating budgets for IT and network related costs.

UED will execute a total of 47 projects (including minor business change requests) with 28 projects within the EDPR submission period. The key projects in the UED IT capital program are:

Table 6-12: IT major projects

#	Project	Capability Area	Total Capex[a]	EDPR Total[b]	Start period	End period
1	ERP –SAP Consolidation	Manage Assets	$29,206,320	$28,083,990	Q3 2010	Q2 2012
2	CIS Migration of Legacy Meters (Type 1-4) ++	Manage Meter Data & Revenue	$7,962,240	$7,723,408	Q3 2010	Q1 2014
3	SCADA Replacement	Manage Network	$7,407,400	$7,407,400	Q1 2012	Q2 2013
4	DMS Upgrade	Manage Network	$6,022,016	$6,022,016	Q3 2013	Q2 2014
5	Identity and Access Management System	Manage Stakeholders	$4,612,608	$4,612,608	Q1 2011	Q1 2012
6	Market System Upgrade (CATS / B2B)	Manage Meter Data & Revenue	$4,290,000	-	Q1 2010	Q2 2010
7	System Rationalisation and Consolidation	Manage Business	$4,228,224	$4,228,224	Q1 2013	Q2 2014
8	Enterprise Content Management System	Manage Business	$4,118,400	$3,951,200	Q1 2010	Q2 2014
9	New Disaster Recovery Data Centre	Manage IT	$4,024,134	$4,024,134	Q3 2014	Q4 2015

#	Project	Capability Area	Total Capex[a]	EDPR Total[b]	Start period	End period
	Implementation					
10	New Production Data Centre Implementation	Manage IT	$4,024,134	-	Q1 2010	Q3 2010
Total top 10 projects			**$75,895,476**	**$66,052,980**		

a This capability area excludes investment as part of the AMI Program

b Project totals include allocation for Delivery costs and provision for Risk, consistent with assumptions in model.

Amounts shown in real 2010 terms.

6.11 Non-network assets - other

6.11.1 Overview

Non-network assets relate to the purchase of:

- vehicles;
- plant and machinery;
- miscellaneous tools & equipment; and
- office accommodation.

Table 6-13 below shows the actual Non-network capital expenditure for the 2006-2010 regulatory period and the benchmark expenditure for the 2011-2016 regulatory period.

Table 6-13: Non-network capital expenditure, 2006 - 2010

	YEAR ENDING 31 DECEMBER				
	2011 $M	2012 $M	2013 $M	2014 $M	2015 $M
Forecast	2.1	4.7	1.9	2.7	1.8

Amounts shown in real 2010 terms.

6.11.2 Basis for proposed Non-network capital expenditure

There are two main drivers for the proposed capital forecasts in this category:

- replacement of fleet; and
- property projects.

Fleet is being replaced and purchased consistent with UED's fleet asset management policy. This amount is consistent with previous expenditure trends. The other item is the refurbishment of office space in order to accommodate the increase in personnel as a result of the 7/11 project. UED will be in-sourcing functions that it had previously contracted out and now requires the office accommodation to accommodate the required personnel.

6.12 Comparison of 2006–10 capital expenditure with 2011–15 forecast

UED is forecasting an increase in total capital expenditure compared to historic levels. In broad terms, the forecast increase in capital expenditure reflects the need to replace an ageing distribution network.

In accordance with clause S6.1.1 (8) of the Rules, this section presents:

- a comparison of the operating expenditure forecast with historical capital expenditure in the current regulatory control period by category; and
- an explanation of significant variations in the forecast capital expenditure from historical operating expenditure.

To address the Rules requirements, Table 6-14 compares forecast capital expenditure for each line item with the historic average over the current period. The table also provides a high-level explanation of the differences.

Table 6-14: Comparison of five year actual and five year forecast capital expenditure

	2006–2010 actual expenditure ($M)	2011–2015 Forecast ($M)	Explanation of variation between forecast and historic capital expenditure
SYSTEM ASSETS			
Reinforcements	121.2	221.3	Demand - $100.1m The increase in demand capital is consistent with the proposed budgets for 2009 and 2010 relating to the replacement of overloaded distribution transformers, replacement of aged zone substation transformers. Other increases are for: Purchase of land for new zone substations - $5m Installation of two new zone substations compared to one in the current period - $10m Eight new zone substation transformers (up from 6) - $15m Mitigation of increased risk of reliability deterioration - $23m. Augmentation of nine sub-transmission lines (three in current period) - $3m New Hastings to Rosebud 66kv line - $17m

	2006–2010 actual expenditure ($M)	2011–2015 Forecast ($M)	Explanation of variation between forecast and historic capital expenditure
			Sub-station augmentation - $27m
Customer initiated	171.0	232.1	Customer-initiated - $61.1m The increase in customer initiated capital is driven by the following factors: The downturn in the financial markets is expected to slow which will result in an increase in capital works compared to the current period There are three large prospective customer projects on the horizon; Telstra data centres - $15m Dandenong South industrial expansion - $7m Dandenong sale yards redevelopment - $7m Increase also due to applying the 2010 benchmark rather than forecast
Reliability & Quality Maintained	170.2	288.7	Replacement - $118.5m Large replacement cycle as assets near end of useful life and/or become an unacceptable bushfire risk: Pole top structures - $42m Zone substation transformer replacement - $8m Proactive replacement of underground cables - $3m Overhead line and overhead service replacement - $8m LV service replacement program - $22m
Reliability & Quality Improvements	12.0	0.0	Improvements no longer economic based on performance targets
Environmental, Safety & Legal	37.7	52.2	Performance - $14.5m Accelerated replacement of neutral screen services. Installation of additional ground fault neutralisers in bushfire areas and harmonic fitters. Additional noise mitigation programs.
Sub-total system assets	**512.1**	**794.2**	

	2006–2010 actual expenditure ($M)	2011–2015 Forecast ($M)	Explanation of variation between forecast and historic capital expenditure
NON-NETWORK ASSETS			
Non-Network General Assets – IT	26.1	98.5	Non-network – IT - $72.5m UED has significant underspent its allowance in the current period. This is partly due to the cancellation of the IMRO program. Part of the IMRO program was the replacement of the current CIS system. This was delayed and is now included as part of the AMI program. Installation of new control room
SCADA and network control	0.0	3.5	Relocation of the control room
Non-Network General Assets – Other	17.4	13.1	No explanation required
Sub-total non-network assets	**43.5**	**116.3**	
Total capital expenditure	**555.6**	**910.5**	

Amounts shown in real 2010 terms.

7. Depreciation

Key messages

- 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.

7.1 Regulatory requirements and chapter structure

Depreciation is an important cost component in UED's building block proposal. For capital intensive businesses, such as electricity network companies, depreciation costs represent a significant element of the company's revenue requirement.

Depreciation can be interpreted in a number of different ways, depending on the purpose to which the concept is being put. In regulatory economics, it is generally regarded as providing a return of capital to shareholders. In theory, 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. In accounting, the approach to depreciation is focused on the task of recognising the capital-related costs incurred in an accounting period. Accounting measures of profitability will be affected by the profile of depreciation.

Clause 6.5.5 of the Rules sets out the following requirements regarding depreciation in a building block proposal:

- subclause (a)(1) requires that depreciation must be calculated based on the value of the regulatory asset base (RAB) at the beginning of each year;
- subclause (a)(2) requires depreciation to be calculated using depreciation schedules nominated by the DNSP in the building block proposal;
- subclause (b)(1) requires that depreciation schedules must be based on the economic life of the assets;
- subclause (b)(2) requires that the recovery of depreciation must be equivalent in present value terms to the value at which that asset or category of assets was first included in the regulatory asset base; and
- subclause (b)(3) requires that the economic life, depreciation rates and methods underpinning the calculation of depreciation for a regulatory control period must be consistent with the distribution determination for that period.

In addition, clause S6.1.3(12) requires the depreciation schedules to be categorised by asset class or category driver, together with details of (and an explanation of the calculation of) the amounts, values and other inputs used to compile the depreciation schedules, a demonstration that the depreciation schedules conform with the requirements set out in clause 6.5.5(b) of the Rules. There are no specific requirements relating to depreciation in the RIN.

The AER's roll forward model, which was finalised in June 2008, determines the closing regulatory asset base for each DNSP for each regulatory control period. This closing RAB value becomes the opening RAB to be used for the purposes of making a distribution determination for the next regulatory control period. The roll forward model is therefore relevant as it reflects the depreciation calculation presented in this Chapter.

In light of the Rules requirements noted above, the remainder of this Chapter is structured as follows:

- Section 7.2 explains UED's proposed depreciation methodology and asset lives;
- Section 7.3 sets out UED's estimated depreciation for the current regulatory period;
- Section 7.4 presents UED's forecast depreciation for the forthcoming regulatory period; and
- Section 7.5 presents UED's forecast tax depreciation for the forthcoming regulatory period.

7.2 Depreciation methodology and asset lives

UED notes that the Rules establish broad principles for depreciation costs, 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[45].

It is also noted that the Rules require annual depreciation to be calculated on the basis of the opening asset base for that year. This approach differs from previous regulatory determinations under the ESC, where annual depreciation recognised capital expenditure during the relevant year.

UED has used the AER's PTRM to calculate depreciation in accordance with Clause 6.5.5 of the Rules. New assets are depreciated according to standard lives for each asset class. Existing assets are depreciated over their remaining asset lives. As noted above, the opening asset value at 1 July 2010 has been calculated applying the AER's Roll Forward Model (RFM).

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[45] **AER, Electricity Distribution Network Service Providers, Roll forward model handbook, June 2008, page 3.**

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 has been obtained from the Network AMP. This document is provided as an appendix to part of this Proposal.

7.3 Regulatory depreciation for the 2006-2010 period

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, 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.

7.4 Forecast regulatory depreciation for the 2010-2015 period

UED has prepared its depreciation forecast for the 2011–2015 regulatory control period, applying forecast asset additions, forecast asset disposals and applying the asset lives listed above. The opening asset values have been calculated in accordance with the AER's roll forward model. The 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 total of the resulting regulatory depreciation allowance is shown in Table 7-3 below.

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.

7.5 Forecast tax depreciation for the 2011-2015 period

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 Tax depreciation has been calculated on a diminishing value basis, using applicable tax depreciation rates.

The forecast tax depreciation schedule for the 2011–2015 regulatory control period, which has been 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 (MOD - $m)

	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.

8. Regulatory asset base

Key messages

- 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.

8.1 Regulatory requirements and chapter structure

In a building block proposal, the return on and return of capital depend on the value attributed to the regulatory asset base ("RAB"). Clause 6.5.1 of the Rules describes the RAB as the value of those assets that are used by the provider to provide standard control services, but only to the extent that they are used to provide such services. The same clause requires the AER to develop and publish a model for the roll forward of the RAB and provides the requirements for the roll forward model.

Schedule 6.1.3(7) requires a building block proposal to contain a calculation of the RAB for each year, using the roll forward model, together with:

- details of all amounts, values and other inputs;
- a demonstration that the amounts, values and inputs comply with the relevant requirements of Part C of Chapter 6 of the Rules; and
- an explanation of the calculation of the RAB for each year and of the amounts, values and other inputs involved in the calculation.

Schedule 6.1.3(10) requires a building block proposal to contain a complete Post Tax Revenue Model and Roll Forward Model. These are both provided with this proposal. Other provisions relating to the regulatory asset base are set out in schedule 6.2. In particular:

- S.6.2.1(c)(1) establishes a value for the RAB of UED as at 1 January 2006 in July 2004 dollars;
- S.6.2.1(c)(2) specifies how this initial value is to be adjusted for the difference in estimated and actual capital expenditure in any previous regulatory control period;
- S.6.2.1(e) specifies the method of adjustment of value of the RAB between regulatory periods; and
- S.6.2.3 specifies the method of adjustment of value of the RAB for each year within a regulatory period.

In light of these Rules requirements, the remainder of this chapter is structured as follows:

- Section 8.2 sets out the RAB as at 1 January 2006, including the adjustments required by S.6.2.1(c)(2);
- Section 8.3 calculates the opening RAB as at 1 January 2011, being the start of the forthcoming regulatory period; and
- Section 8.4 establishes the opening and closing RAB for each year of the forthcoming regulatory period.

8.2 Calculation of RAB as at 1 January 2006

Clauses S6.2.1(c)(1) and (2) of the Rules specify that UED's opening RAB is $1,220.3 million (as at 1 January 2006 in July 2004 dollars), and must be adjusted for the difference between:

- any estimated capital expenditure that is included in those values for any part of a previous regulatory control period; and
- the actual capital expenditure for that part of the previous regulatory control period.

This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure. The RAB must also be adjusted for the effects of inflation. Table 8-1 below provides the necessary calculation in accordance with 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
Actual disposals	-1.3
Revised opening RAB as at 1 January 2006 (2010 prices)	**1,388.6**

Note : CPI calculation is based on Sept 93 / Sept 09 index i.e. UED has applied the same lagged method adopted in the current regulatory control period.

UED's actual capital expenditure for calendar year 2005 was $44.7 million lower than the forecast expenditure. UED's actual customer contributions for 2005 was $13.4 million higher than the forecast and disposals for 2005 was also $1.3 million higher than forecast. These differences have been correctly input into the AER's roll forward model.

The AER's roll forward model requires the 1 January 2006 RAB value to be input in June 2010 dollars. The RAB value in June 2004 dollars must be escalated to the RAB value in June 2010 prices. This escalation is consistent with Clause 6.5.1 (e)(3) of the Rules, which states:

> " … the roll forward of the regulatory asset base from the immediately preceding regulatory control period to the beginning of the first regulatory year of a subsequent regulatory control period entails the value of the first mentioned regulatory asset base being adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism (or control mechanisms) for standard control services during the preceding regulatory control period."

The escalation of the RAB to June 2010 applies to the annual CPI All Groups, Weighted Average of Eight Capital Cities.

8.3 Calculation of RAB for the start of the forthcoming regulatory control period

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 has applied the AER's Roll Forward Model, including the following adjustments:

- Adjustment for inflation: The RAB has been indexed to reflect actual inflation.
- Disposals of assets: Asset disposals largely comprise assets, such as vehicles, land and buildings. Asset disposals are recognised in the year of disposal, with the net proceeds deducted from the RAB.
- Estimates 2009 and 2010 Regulatory Years: At the time of preparing this regulatory proposal, actual data for 2009 and 2010 regulatory years is not available for capital expenditure, depreciation and asset disposals. Latest available company forecasts have therefore been applied for 2009 and 2010 to determine the asset base as at 1 January 2011.

Internal company forecasts of capital expenditure, customer contributions and asset disposal data for 2009 have been applied in this Proposal. Depreciation has been based on the amount allowed in the 2006 EDPR. The roll forward will be adjusted in the Revised Proposal to reflect actual 2009 data. Adjustments to the regulatory asset base to reflect 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	1,388.6	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

	2006 $M	2007 $M	2008 $M	2009 $M	2010 $M
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.

8.4 Roll-forward of the RAB for each year of the forthcoming regulatory period

UED has modelled the roll forward of the RAB for the next regulatory control period based on the closing RAB value as at 31 December 2010, as detailed in Table 8-2 above.

UED has applied the methodology set out in Schedule 6.2.3 of the Rules and has used the AER's Post Tax Revenue Model roll forward model.

The assumptions used by UED in rolling forward the RAB in the forthcoming regulatory period are as follows:

- forecast capital expenditure is consistent with the categories and amounts presented in Chapter 6 of this Regulatory Proposal;
- depreciation has been calculated on a straight line basis, using asset lives as provided in Chapter 7; and
- asset disposals are forecast to be zero; .

The established RAB for each year of the forthcoming regulatory period is shown in Table 8-3.

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
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.

9. Cost of capital and taxation

Key messages

- The provision of an adequate return on capital is of critical importance to UED's owners and its customers. UED competes with other energy infrastructure companies both in Australia and overseas to raise capital to support its business. Over the next 10 years, the investment required in regulated Australian energy infrastructure is around $40 billion. 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.

- 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.

- 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. 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*** (emphasis added) 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 therefore require the AER to err on the upside where uncertainty may exist or measurement may be difficult (e.g. the MRP), so as to ensure the necessary network investment can occur.

- UED's WACC proposal accords with these requirements. It adopts 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 considers that there is persuasive evidence available now that demonstrates that the values specified in the SORI for the MRP and gamma are inappropriate, and that in the particular case of the forthcoming determination for UED, departure from those values is justified, in accordance with the provisions set out in clauses 6.5.4(g) and (h) of the Rules.

- Whilst there has been emerging signs of an economic recovery in recent months, the global financial crisis is far from over. Recent comments by the Reserve Bank of Australia indicate that the recovery remains fragile and markets have yet to return to pre-crisis levels. Moreover, some authoritative commentators cite a high risk of a double-dip recession.

- UED proposes a value of 8 per cent for the MRP, and a value of 0.5 for the gamma.

- UED's proposed WACC for the purpose of this Regulatory Proposal adopts a risk free rate (and debt risk premium) measurement period spanning the first 15 business days of October 2009.
- UED's proposed nominal vanilla WACC for the purpose of this Regulatory Proposal is 10.86 per cent.
- UED has written to the AER to set out the measurement period of the nominal risk free rate (and debt risk premium) that the company proposes 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 has requested that the letter be kept confidential.

9.1 Introduction

Clause 6.4.3(a)(2) of the Rules identifies "return on capital" as one of the building blocks for determining the annual revenue requirement of a DNSP. The return on capital building block is the product of the regulatory asset base value (which is addressed in chapter 8 of this Regulatory Proposal) and the weighted average cost of capital, or WACC.

This chapter sets out UED's proposal regarding the WACC. The chapter also sets out UED's proposed value of imputation credits (gamma) which is used to calculate the estimated cost of corporate income tax in accordance with clause 6.5.3 of the Rules.

The Rules require that the return on capital be calculated in accordance with clause 6.5.2 and any applicable Statement of Regulatory Intent ("SORI") on the WACC parameter values.

UED's proposal addresses the relevant provisions of the Rules and the SORI which was issued in May 2009 ("the applicable SORI").

In setting out its proposals, UED notes 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.

Against this backdrop, the remainder of this chapter is structured as follows:

- Section 9.2 provides an overview of the regulatory requirements governing the determination of the WACC.
- Section 9.3 provides an overview of UED's proposed WACC.
- Sections 9.4 to 9.10 then provide detailed information to substantiate, in accordance with the applicable regulatory requirements, the WACC parameter values that UED proposes to adopt.

9.2 Regulatory requirements

9.2.1 Definition of return on capital

Clause 6.5.2(b) of the Rules defines the rate of return for a DNSP as the cost of capital measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the distribution business of the provider. It is to be calculated as a nominal post-tax weighted average cost of capital ("WACC") given by the following formula:

$$WACC = k_e\ E/V + k_d\ D/V$$

where:

k_e is the return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

$$r_f + \beta_e \times MRP$$

where:

r_f is the nominal risk free rate for the regulatory control period;

β_e is the equity beta; and

MRP is the market risk premium.

k_d is the return on debt and is calculated as:

$$r_f + DRP$$

where:

DRP is the debt risk premium for the regulatory control period;

E/V is the value of equity as a proportion of the value of equity and debt, which is 1 - D/V; and

D/V is the value of debt as a proportion of the value of equity and debt.

9.2.2 Requirements of the SORI and the Rules

Clause 6.5.4 of the Rules provides for certain matters relating to the WACC to be reviewed periodically by the AER. Following such a review, the AER must issue a SORI setting out the values, methods and credit rating levels for DNSPs. In accordance with these requirements, the AER issued a SORI on 1 May 2009, which applies to the current review. The various matters set out in the SORI and in Clause 6.5.2 of the Rules are summarised in the table below.

Table 9-1: WACC parameters set out in clause 6.5.2 of the Rules and the SORI

WACC Parameter	Value or methodology	Specified in
Nominal Risk Free Rate	The annualised yield on Commonwealth Government bonds (CGS) maturing in 10 years from any day in the measurement period (see below). If necessary the 10 year yield is to be determined by linear	Clauses 6.5.2(c) and (d) of the Rules; SORI clauses 3.2(a) and

WACC Parameter	Value or methodology	Specified in
	interpolation of the yields on the two CGS closest to the 10 year term and which straddle the 10 year expiry date.	3.3
Measurement period for the nominal risk free rate and Debt Risk Premium	Either: (i) a period ('the agreed period'), being one which is as close as practically possible to the commencement of the regulatory control period, proposed by the relevant Distribution Network Service Provider, and agreed by the AER (such agreement is not to be unreasonably withheld), or (ii) a period specified by the AER, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under paragraph (i), and is also to be calculated in accordance with clauses 6.5.2(c)(1), 6.5.2(c)(2)(iii) and 6.5.2(c)(2)(iv) of the NER.	SORI, clause 3.2
Debt Risk Premium	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 (see below).	Clause 6.5.2(e) of the Rules
Credit Rating for the purpose of determining the Debt Risk Premium	BBB+	SORI clause 3.7
Gearing	60% debt to total assets	SORI clause 3.6
Beta (β)	0.8	SORI clause 3.4
MRP	6.5%	SORI clause 3.5
Gamma	0.65	SORI clause 3.8

UED's building block proposal is required to set out its calculation of the proposed rate of return including any proposed departure from the values, methods or credit rating levels set out in the applicable SORI.

9.2.3 The AER's decision-making framework

In relation to the values and methodologies for the rate of return that are specified in the applicable SORI, the Rules require the AER to make a distribution determination that is 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 (clause 6.5.4(g)). In deciding whether a departure is justified for a distribution determination, clause 6.15.4(h) requires the AER to consider:

> " (1) the criteria on which the value, method or credit rating level was set in the statement of regulatory intent (the underlying criteria); and
>
> (2) whether, in the light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in the statement inappropriate."

In deciding whether a departure is justified, the AER should also consider its broader objectives, and in particular, its 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, in the context of the transitional rules as they applied to the cost of capital withholding agreement.[46] It stated as follows:

  > " It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterised by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset (e.g., by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.
  >
  > Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs."

- 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.

As noted elsewhere in our regulatory submission, UED faces a large capital expenditure program 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.

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[46] Energy Australia and Others [2009] ACompT 8, paragraphs 77-78. The decision also notes that, while the transitional rules provide the context for proposing an averaging period, any proposal must also be in accordance with the NEL, and more specifically with the national electricity objective and the revenue and pricing principles set out in s7 and s7A, respectively.

Within this context, it is important for the AER to ensure that the WACC that is allowed for UED 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.

UED's proposed WACC parameters (set out below) have been derived in accordance with the Rules requirements and the broader principles set out in the National Electricity Law.

9.2.4 Global Financial Crisis

Over the last 18 to 24 months the global financial and capital markets have experienced some of the most challenging conditions in history. These recent events have come to be referred to as the "Global Financial Crisis" ("GFC"). These terms, now widely used by world leaders, leading financial markets participants, central bankers, financial markets regulators and market commentators alike, are not chosen lightly. Their choice of words conveys the unprecedented nature and challenges with which the global economy and financial markets have had to contend.

The GFC has resulted in a:

- material increase in the cost of capital across both debt and equity markets;
- general decline in the level of investor risk appetite;
- reduction in liquidity and access to capital across virtually all markets; and
- change in market views on acceptable gearing levels.

Whilst there have been some recent signs of improvement in debt and equity capital markets, access to funding generally remains challenging and financial market conditions continue to exhibit volatility.

In assessing the value for the market risk premium for the purposes of the SORI, the AER took note 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 it had reviewed provided a sufficiently compelling case for a conclusion that the prevailing MRP was above the long term level of 6 percent. 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 that what it would have been, if it were to truly reflect prevailing conditions in the market for funds.

UED accepts that measuring the unobservable MRP is a difficult matter. However, 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 'at least' recover its efficient costs of operation. As we demonstrate in our discussion on the MRP later in this regulatory proposal, current market indicators suggest that investors are now demanding significantly higher returns to provide new equity.

9.3 Overview of the proposed WACC

Table 9-2: Overview of UED's proposal

Parameter	Summary of value methodology under the Rules and the SORI	UED 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 intends 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 considers that there is 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). Accordingly, UED has proposed values for these parameters that depart from those required in the SORI.

UED has proposed a nominal vanilla WACC of 10.86 per cent for the purpose of this Regulatory Proposal. This is based on the parameter values set out in Table 9-3 below. The table also provides a cross-reference to the sections of this chapter that provide information to substantiate the parameter value proposed by UED.

Table 9-3: Calculation of UED's nominal WACC

Parameter	Proposed Value	Section Reference
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%	

The basis for the proposed parameter values and the evidence to justify the departures from the SORI (in relation to the values of the MRP and gamma) are outlined in the following sections.

9.4 Risk free rate

As already noted, the SORI requires that:

- the nominal risk free rate be calculated on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years (based on the indicative mid rates published by the Reserve Bank of Australia);
- the period of time in which it is to be calculated should be as close as practically possible to the commencement of the regulatory control period, and should initially be proposed by the DNSP and agreed by the AER.

It is noted that in the recent ruling of the Australian Competition Tribunal in the matter of Application by EnergyAustralia and Others [2009], the Tribunal has, for the first time ruled on the issue of appropriate measurement (or averaging) periods. The Tribunal found that the AER was in error in unreasonably withholding agreement to averaging periods proposed by the businesses[47]. In reaching this conclusion the Tribunal appeared influenced by the particular cost of capital estimation process set out in the Rules (which pre-specify a number of WACC parameters) thereby already shifting the cost of capital estimation process from an internally consistent 'point in time' calculation[48]. Importantly, the Tribunal

[47] 1 **Clause 6.5.2 of the Rules specifically provides that agreement may not be unreasonably withheld.**

[48] **Application by EnergyAustralia and Others [2009] ACompT 8 [84-88]**

also rejected the logic of seeking to closely align the start of the regulatory period and the averaging period in circumstances where a single cost of capital value is applied to calculate the return on capital for each of the five years of a regulatory period (which is consistent regulatory practice in Australia).[49] The Tribunal instead held that the only clear ground for rejecting the businesses' proposed averaging periods under the Rules is that the period proposed would generate an estimate that was inappropriately low or high.[50]

UED has written to the AER to set out the measurement period of the nominal risk free rate (and debt risk premium) that the company proposes 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 has requested that the letter be kept confidential.

The risk free rate proposed in this Regulatory Proposal is indicative only and is based on the 15 business day averaging period commencing on 1 October 2009 and ending on 21 October 2009. This rate is proposed to facilitate the calculation of the proposed rate of return at the time of submitting this proposal. As there is no 10 year Commonwealth Government bond maturing in November 2019, UED has estimated the appropriate rate by interpolating on a straight line basis between the March 2019 and the April 2020 Commonwealth Government bond yields.

9.5 Equity beta

The SORI requires that an equity beta value of 0.8 be adopted. Although UED considers that there remains strong evidence[51] to support the continued application of an equity beta value of 1.0, the company nonetheless proposes to adopt an equity beta value of 0.80 consistent with the requirements of the SORI.

9.6 Market risk premium

9.6.1 Recap on the basis for the MRP value in the SORI

The MRP is the expected return over the risk-free rate that investors would require in order to invest in a well-diversified portfolio of risky assets. The MRP represents the risk premium that investors who invest in such a portfolio can expect to earn for bearing only non-diversifiable risk.

The SORI requires that a value of 6.5 per cent be adopted for the MRP. The AER's WACC decision makes it clear that this assumed value for the MRP, which has been 'grossed-up' for an assumed value of imputation credits of 0.65 from 1987 onwards, is based on the following:

- Historical or ex-post measures of the MRP, particularly for the periods 1883 to 2008, 1937 to 2008 and 1958 to 2008. Whilst historical data is not strictly forward-looking, the AER accepts that investors' forward looking expectations will be based on past

49 Application by EnergyAustralia and Others [2009] ACompT 8. Page 88.

50 IBID. Page 89.

51 Joint Network Industry Submission: AER Proposed Determination - Review of the Weighted Average Cost of Capital (WACC) parameters for electricity transmission and distribution, February 2009.

experience. For the AER's preferred estimation periods the realised premium is in the order of 6 per cent, or within a range of 5.7 to 6.2 per cent. However, the AER also noted that these results were extremely sensitive to the estimation period chosen (for example, if the estimation periods were ended in 2007 rather than 2008, the range would have been 6.6 to 7.2 per cent).

- Forward-looking or ex-ante estimates of the expected MRP derived from cash-flow based measures; information from futures markets; and implied spreads on corporate bonds indicates that the short-term forward looking premium is currently well above 6 per cent (after having been consistently well below 6 per cent up until 2008).
- Information from surveys, which indicates that 6 per cent is a commonly used value.

The AER commented that 'primary weight' should be given to historical measures of the MRP, although some weight should be given to ex-ante measures and survey based evidence[52]. The AER also recognised the impact of the global financial crisis on the MRP. The AER concluded that an MRP of 6.5 per cent is reasonable, at this time, and is an estimate of a forward looking long term MRP commensurate with the conditions in the market for funds that are likely to prevail at the time of the reset determinations to which its WACC review applies[53].

9.6.2 Persuasive evidence to justify a departure from the SORI

Clause 6.5.2(g) states that:

> " A distribution determination to which a statement of regulatory intent is applicable must be consistent with the statement unless there is persuasive evidence justifying a departure, in the particular case, from a value, method or credit rating level set in the statement."

Clause 6.5.2(h)(2) provides that in deciding whether a departure from a value, method or credit rating level set in a statement of regulatory intent is justified in a distribution determination, the AER must consider:

> " whether, in the light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in the statement inappropriate."

UED considers that there is persuasive evidence available now that demonstrates that a value of 6.5 per cent for the MRP is inappropriate and that in the particular case of the forthcoming determination for UED, departure from the 6.5 per cent MRP value specified in the SORI is justified.

There are two key reasons for this:

- The AER's decision on the MRP in the SORI was an arbitrary one, designed to take into account the longer term impact of the GFC on the MRP; and

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[52] **AER, Review of the weighted average cost of capital (WACC) parameters, Final Decision, May 2009, page 236.**

[53] **IBID. page 238.**

- The evidence suggests that the current cost of raising equity is now well above that implied by the SORI. This evidence comes in the form of:
  - Yield base indicators of the current cost of raising equity;
  - The implications of the ongoing market volatility for the current cost of equity; and
  - The spreads on bond yields relative to the AER's view of the MRP.

UED's reasoning and evidence is set out below. It also shows that while estimating the ex ante MRP is extremely difficult, this is not a reason to provide an MRP which does not reflect the current cost of equity. Indeed, given the level of uncertainty in the market, and the need for investment, it reinforces the need to err of the side of ensuring that allowed revenues are at least sufficient to allow for efficient investment.

9.6.3 The basis for the AER's decision on the MRP in the SORI

In its WACC decision, the AER noted that its obligation under the Rules to set a rate of return that was forward-looking and which reflects prevailing market conditions should be interpreted in the following way:

> " … it is a requirement that the AER must have regard to the need for the rate of return to reflect forward looking expectations, as at the relevant point in time. That relevant point in time is at the time of the individual reset determinations, rather than at the time of the AER's WACC review. Accordingly, the AER should determine each parameter, including the MRP, in such a way as it is relevant for a 10 year perspective (consistent with the term of the risk-free rate) from the commencement of the next regulatory control period for each service provider affected by this review."[54]

The AER further noted that for parameters such as the MRP, a difficulty arises since the Rules require the AER to lock-in either a value or methodology, but in the case of the MRP – which does vary over time according to economic conditions – there is no adequate method of automatically updating the MRP at the time of each reset determination. A clear risk with locking-in a value for the MRP at each WACC review, particularly when market conditions are highly uncertain, is that this value may change materially at the time of a reset determination, such that it no longer supports a forward-looking rate of return at that time. There is therefore a degree of tension between the requirement to lock-in a value for the MRP at the WACC review and the requirement to have regard to the need for the rate of return to reflect forward-looking expectations commensurate with prevailing conditions at the time of each reset determination.

The AER acknowledged this situation as follows:

> " … if the MRP varies over time, then by definition, the locking in of a value may not always completely reflect forward looking expectations prevailing at the time of each reset determination. Accordingly, for some reset determinations the actual (unobservable) MRP may be somewhat above this value, though for other reset determinations the actual (unobservable) MRP maybe be somewhat below."[55]

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[54] **IBID. Page 188.**

[55] **IBID. Page 191.**

The AER's decision on the MRP in the SORI was therefore trying to balance a number of competing objectives and was setting a value for the MRP that could, in principle, have a life of 10 years. The AER's decision also acknowledges that the value used in the SORI might not be appropriate in all instances.

UED's next regulatory control period is to commence on 1 January 2011, a period that is just 14 months away. Whilst there has been emerging evidence of a recovery in economic conditions in the Australian market in recent months, we consider that it would be premature to suggest with any confidence that a turnaround has occurred and that the market cost of equity has returned to levels that preceded the global financial crisis. Indeed, there is a strongly held view that any further recovery over the near term may reverse, or at best is likely to be mild. As the Organisation for Economic Co-operation and Development has noted in its recent Interim Economic Assessment, despite positive signs of a turnaround on many indicators:

> " … numerous headwinds imply that the pace of the recovery is likely to be modest for some time to come. Ample spare capacity, low levels of profitability, high and rising unemployment, anaemic growth in labour income and ongoing housing market corrections will moderate any uptick in private demand. At the same time, the need remains for households, businesses, financial institutions and governments to repair the damage to their balance sheets." [56]

Similar observations have also recently been made by the Reserve Bank of Australia ("RBA"). In a recent speech by Malcolm Edey, RBA Assistant Governor, it was noted that despite encouraging signs of improvement in recent months, it is necessary to exercise cautious optimism:

> " … Given these developments, my theme today is one of cautious optimism about the global situation. We can't yet say that things are back to normal, and we still can't rule out further setbacks …
>
> … the extreme risk aversion of late last year has been easing for some months now, and the banks' access to wholesale funding markets has been improving. It's important to keep this in perspective: these market indicators are still, in some cases, a long way from pre-crisis levels, particularly for borrowing costs at longer maturities."[57]

The prevailing market outlook therefore supports the view that any sustained improvement in market conditions is still highly uncertain and a return to pre-crisis conditions is some considerable way off. In particular, page 3 of the Reserve Bank's latest (August 2009) Statement on Monetary Policy notes that significant uncertainty remains regarding the economic outlook, with the possibility that the recovery since the March 2009 quarter may be short-lived:

> " Given the rapidly evolving international financial and economic conditions, the outlook for the Australian economy continues to be subject to considerable uncertainty, although the risks are more balanced than they have been for some time. With confidence globally still fragile, it remains possible that the outlook could again weaken."

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[56] **OECD, What is the Economic Outlook for OECD countries? An Interim Assessment, 3 September 2009, page 2.**

[57] **Edey, M. "The evolving financial situation", speech delivered at the Finsia Financial Services Conference, 28 October 2009.**

Given this outlook, UED believes that at the time the AER makes its forthcoming determination, it is likely that the return on equity required by investors in the market will reflect a level of risk aversion which exceeds that reflected in the value allowed for the MRP in the SORI[58].

9.6.4 Yield based indicators of the current cost of equity

Yield based indicators suggest that the current cost of raising new equity is now above that implied by the SORI. Indeed, market evidence recently compiled by the Financial Investor Group ("FIG") on the cost to publicly listed Australian companies with regulated network assets of raising new equity in the current environment (as implied in dividend yields) supports the view that investors are currently expecting a (pre-tax) return on equity in the range of 15 per cent to 18 per cent[59].

UED notes that setting an appropriate cost of capital must ultimately be guided by the requirements of investors, noting that the long term interests of consumers will not be served by inadequate levels of network investment. Failure to allow regulated businesses a reasonable opportunity to earn a return which is consistent with that expected by investors will mean that capital will be diverted to other investment opportunities where capital – which is currently expensive and scarce – can be more productively employed.

UED considers that the ongoing uncertainty regarding the outlook for the global economy and capital markets, coupled with the available evidence on the cost of equity faced presently by regulated utilities provide persuasive evidence that demonstrates that a value of 6.5 per cent for the MRP is inappropriate and that in the particular case of the forthcoming determination for UED, departure from that value is justified.

Moreover, new evidence has become available which indicates that the forward looking MRP is 12.0 per cent per annum and that the best estimate for the MRP over the 2011-2015 regulatory period is 8.0 per cent per annum.

The study by Dr. Stephen Bishop and Professor Robert Officer of Value Adviser Associates captures the volatility trend in the ASX All Ordinaries Accumulation Index since 1980. It shows that the equity market has and still is experiencing and an unusual period of high risk relative to historical norms.

UED considers that the unique environment within which the AER is undertaking its review of this Regulatory Proposal justifies a departure, in this particular case, from the MRP value specified in the SORI. In particular, the ongoing uncertainty regarding the global capital market outlook and the impact of this uncertainty on investors' required returns, coupled with the new evidence presented below, constitute relevant factors (pursuant to clause 6.5.4(h)(2)) that justify a departure from the SORI's MRP value. UED's view is supported by the following conclusions of Bishop and Officer, which are set out in their report dated October 2009 (a copy of which is provided as an Appendix to this Regulatory Proposal):

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[58] **This implicitly requires holding the equity beta constant at the value allowed in the SORI.**

[59] **The Financial Investor Group, Supplementary Submission to the ERA regarding its Draft Decision on Western Power's Proposed Revisions to the Access Arrangement for the South West Interconnected Network, Revised Final Version 22 October 2009, page 6.**

> " The "MRP" will change over time to reflect the "market's" view of the risk and attitudes to risk. A positive risk premium exists because future return outcomes are not known. We doubt whether the distribution of premiums is constant over time. Consequently we do not believe that a constant MRP reflecting the long term average is appropriate under current economic circumstances in particular.
>
> In the past we have recommended the use of the long term average historical MRP. This is not because we believe it to be stable over time but because there has been neither a well developed theory to predict and explain changes nor has there been a supportable empirical base for moving away from the long term average.
>
> Three factors have combined to change this departure from our prior recommendations to use a long term average MRP to reflect a forward MRP:
>
> a) A period of unusual economic circumstances in the form of the global financial crisis;
>
> b) The availability of a forward view of market risk though the implied volatility of options on the stock market index;
>
> c) Promising research guiding the time period of departures from the norm.
>
> While still an evolving area for research we are of the view that advances to date and the recent events in the economy warrant a departure from the use of the long term average."[60]

Bishop and Officer go on the state that:

- 1. their estimate of the current forward looking MRP is 12.0 per cent per annum;
- 2. their best estimate of the MRP over the regulatory period (i.e. January 2011 - December 2015) is in the range of 7 – 10.6 per cent per annum; and
- 3. they recommend adopting an MRP of 8.0 per cent for the regulatory period.

These views were formed by reference to the forward view of volatility implicit in the pricing of options on the ASX 200 index and by the current high spreads in yields on corporate debt. In relation to their implied volatility analysis, Bishop and Officer:

- develop a measure of implied volatility based on the S&P/ASX 200 index options with a three month horizon;
- demonstrate that there is a sufficiently strong relationship between their measure of the implied volatility of the stock market and realised volatility, as well as between realised volatility and realised market return; and
- apply the required rate of return per unit of risk implied from the relationship between realised volatility and realised market return[61], to the measure of implied volatility to derive a forward-looking MRP.

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[60] **Dr. S Bishop and Professor R Officer (Value Adviser Associates), Market Risk Premium, Estimate for 2011-2015, October 2009 (Bishop and Officer (2009)).**

[61] **The analysis necessarily requires the use of constant required rate of return per unit of risk. Bishop and Officer (2009) estimate this rate to be about 50 basis points.**

Based on this analysis, Bishop and Officer estimate that the implied MRP is currently 12.2 per cent per annum, which is substantially above the long term historical average MRP of 7.0 per cent per annum.(page 10, Bishop and Officer (2009)).. However, they acknowledge that the MRP is not stationary and changes over time. Further analysis conducted by Bishop and Officer (and set out in their report, which is appended to this Regulatory Proposal) led them to recommend an MRP of 8.0 per cent over the 2011-2015 regulatory period.

Bishop and Officer also analysed spreads on bond yields to derive a forward view of the MRP. As there is some degree of consistency between spreads on corporate bonds and the risk premium required by equity investors, the observed corporate bond spreads can provide a good indicator of the likely required equity market returns. Analysing BBB-rated seven year corporate bonds, Bishop and Officer note that current spreads are at elevated levels and substantially above historical levels. Their analysis confirms that there is a high degree of consistency between their implied stock market volatility measure and the spread on BBB-rated seven year corporate bonds, which is currently at elevated levels.

The continuing high level of corporate debt risk premia provides another indicator that the MRP remains at substantially elevated levels, and that this situation is likely to persist for some time. It also suggests that the AER's SORI decision does not reflect this situation.

9.6.5 Market volatility and the current cost of equity

Based on prevailing yields on 10 year Commonwealth Government Securities (5.5 per cent), the implied post-tax nominal cost of equity using the values in the SORI for the MRP and equity beta is approximately 10.7 per cent. By contrast, the credit spreads for 10 year BBB+ debt as estimated by Bloomberg currently indicate that the required pre-tax nominal return on 10 year BBB+ rated debt is around 10.2 per cent. That is, using the current SORI values, it would appear that shareholders are willing to invest for a rate of return that is only 50 basis points higher than the rate at which financiers are willing to provide fixed rate BBB+ rated 10 year debt.

This result seems anomalous, particularly given the substantially higher levels of risk that equity holders bear relative to debt providers. There is simply no logical basis on which to conclude that equity investors would be prepared to invest for such a small margin over the return which debt holders can get. It should be remembered that equity ranks behind debt in the event of company failure (full or partial) and as such carries a much greater risk, and as such expect a significantly greater return.

The relative historical risk premiums between debt and equity investment in the Australian market do not support the above result.

The returns available on debt compared to the implied returns available on equity using the estimate of the MRP outlined in the SORI demonstrate that the latter is the inadequate.

UED considers that the information and analysis set out above (and in the report of Bishop and Officer, appended) provides persuasive evidence available that demonstrates that a value of 6.5 per cent for the MRP is inappropriate, and that in the particular case of the forthcoming determination for UED, departure from the 6.5 per cent MRP value specified in the SORI is justified. UED's proposed MRP is set out below

9.6.6 UED's proposed MRP

As noted in section 9.2, the AER is obliged to provide UED with a rate of return which is set to appropriately reflect market conditions at the time of its determination. The new evidence provided in this submission indicates that the SORI value for the MRP significantly understates the MRP that is likely to prevail over the 2011-2015 regulatory period. Therefore, if it were to be applied, to set UED's cost of capital over the forthcoming regulatory period, therefore would be insufficient incentives for efficient investment in electricity distribution infrastructure over the period, and this would be contrary to the long term interests of consumers and hence the National Electricity Objective.

UED considers that there is a strong case for the AER to depart from the SORI value for the MRP for this particular determination, 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 regarding investors' forward-looking required rates of return in the present environment of on-going high uncertainty; and
- UED's contention 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.

UED considers that the matters noted 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.

Based on the evidence presented in this Regulatory Proposal and the appended report of Bishop and Officer, UED considers that there is persuasive evidence to adopt a value for the MRP of 8 per cent for the purpose of the AER's determination for the forthcoming regulatory period.

9.7 Gearing

The SORI requires that the value of debt as a proportion of the value of debt and equity (D/V or "gearing") be set at 0.60. UED proposes to adopt a value of 0.60 for the gearing level which is consistent with the SORI.

9.8 Credit rating and debit risk premium

The SORI requires that the benchmark credit rating for a DNSP be set at BBB+ for the purpose of determining an appropriate rate of return. UED proposes to accept the credit rating level of BBB+ as set out in the SORI. Accordingly, we have established a debt risk premium ("DRP") for use in the WACC calculation based on this benchmark credit rating.

9.9 Estimating the debt risk premium

9.9.1 Source of information for credit spreads

The AER's preferred approach to estimating the DRP relies on Bloomberg estimates of fair yields on long term corporate bonds. Bloomberg is preferred over CBA Spectrum as a data source since the AER believes that its previous reviews have indicated that Bloomberg fair yield estimates of the yield on 10 year BBB+ rated corporate debt were more consistent with the observed yields of similarly rated actual bonds.

The AER has recently revisited this issue on two occasions. In its determination of the distribution revenues for the NSW electricity distribution businesses earlier this year, the AER reaffirmed its conclusion that Bloomberg fair yields were preferred since they were more closely aligned with actual market observations. Furthermore, the AER also considered that in terms of the differences in methodology used by Bloomberg and CBA Spectrum for estimating fair/predicted yields, wider market representation was reflected in the Bloomberg estimates.

UED, jointly with the other Victorian electricity distribution businesses, has commissioned PricewaterhouseCoopers ("PWC") to provide advice on the reliability of Bloomberg-based debt risk premiums. This advice was commissioned to address our concerns that the process adopted by Bloomberg to calculating its fair yield curves is subjective and highly non-transparent. These concerns have previously been outlined in the joint submission to the AER by the Victorian DNSPs in response to the draft determination for AMI cost recovery [62], and also in a report by CEG which accompanied the Victorian distributors' joint AMI submission[63].

PWC has been requested to:

1 Propose a methodology to test whether the Bloomberg fair value curves that the AER has relied upon in previous determinations reasonably meets the legislative requirements;

2 Propose an alternative methodology for calculating the debt risk premium that best meets the legislative requirements should Bloomberg fail the above test; and

3 Apply the Bloomberg test and if necessary, the alternative methodology during the first 15 trading days in October 2009.

Appendix G-5 of this proposal contains the PWC report[64].

PWC's key findings 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

[62] **Joint submission by the Victorian DNSPs on the debt risk premium in response to the AER draft determination on 2009-2011 AMI budget and charges application, 11 September 2009.**

[63] **CEG, Estimating the cost of 10 year BBB+ debt during the period 17 November to 5 December 2008, September 2008.**

[64] **PricewaterhouseCoopers, Methodology to Estimate the Debt Risk Premium, October 2009.**

- o 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.

These tests are recommended since there is evidence that during the GFC, the application of the Bloomberg fair value curve methodologies systematically understated the true cost of the relevant debt.

2 Based on data during the first 15 trading days of October 2009, Bloomberg has passed each of these tests. As Bloomberg only produces fair value curves out to a seven year term to maturity for BBB (as well as A and AA) corporate bonds, some form of extrapolation will be necessary to derive an implied credit margin for a 10 year BBB bond. It is recommended that a linear extrapolation of the Bloomberg BBB credit margins between five and seven years be used for this calculation. The application of this estimation procedure resulted in a debt risk premium of 471 basis points.

3 In the event that future application of these tests to Bloomberg indicates that Bloomberg fails any of these tests, further analysis will need to be undertaken, and the extent of this further analysis should be determined by reference to the reasons for the failed test(s). PWC have therefore proposed a range of analyses that could be undertaken for this purpose.

UED proposes that the tests and analyses recommended by PWC be applied during the averaging period set out in Section 9.4.

9.9.2 Allowance for debt raising costs

The AER's methodology for estimating the allowance for debt raising costs relies upon an approach which was established by the Allen Consulting Group ("ACG") in 2004[65]. This methodology established a debt raising cost benchmark that was based on a benchmark bond issue size of $200m and an estimate of the number of such bond issues that would be required to rollover the entity's benchmark debt share of the regulatory asset base. The debt raising cost benchmark itself reflected ACG's estimates of the direct costs associated with raising debt such as underwriting fees and credit rating fees. ACG noted in its analysis that for future use, the analysis should be updated using data based on a rolling five year period.

The AER's most recent application of ACG's methodology for determining the allowance for debt raising costs was in its determination of distribution revenues for the NSW electricity distribution businesses for 2010-2015. For the purposes of this determination, the AER updated and expanded ACG's 2004 analysis by including more recent debt raisings in its sample. Whilst this dataset was an updated set, UED notes that it contains debt raising data over the period 2000 to 2008 and is therefore not strictly in line with ACG's recommendation to update the analysis based on a rolling five year period.

UED is also aware of recent analysis that has been undertaken by CEG which found that the AER's expanded dataset included only a fraction of the number of bond issues that have occurred over the last five years[66]. To the extent that relevant bond issues have been

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[65] **Allen Consulting Group (ACG), Debt and equity raising transaction costs: final report to the ACCC, December 2004.**

[66] **CEG, Debt and equity raising costs, A report for ETSA, June 2009, page 7.**

omitted in the AER's sample, the AER's updated estimates of debt raising costs would be misstated.

In fact, one of the key findings of the CEG report is that after expanding the dataset to include the full number of bond issues made over the past five years, the AER's updated estimates of debt raising costs have been materially understated, particularly so after taking into account ACG's failure to amortise upfront transactions over the tenor of the bond issue using an appropriate cost of capital in calculating an annualised cost[67].

Table 9-4: Results of CEG's analysis on underwriting fess for issues over five years (basis points)

Sample of bond issues utilised	Issues	Mean	Median
AER full sample	11	7.0	6.5
AER sample, 5 year tenor	5	8.1	9.1
AER sample, 10 year tenor	6	6.1	5.8
Bloomberg data, excluding convertible bonds	158	25.7	9.1
Bloomberg, excluding banks, finance, government and convertible bonds	30	30.2	16.6
Bloomberg, excluding banks, finance, government and convertible bonds, value weighted	30	20.6	n/a
Bloomberg, excluding banks, finance, government and convertible bonds, single issue	25	24.9	9.1

Source: CEG, Debt and Equity Raising Costs, A report for ETSA, June 2009, Table 4

CEG concludes from its analysis that the minimum estimate for the benchmark underwriting fees component of debt raising costs is around 9.1 basis points, but this would represent a highly conservative estimate. A more appropriate estimate would be based on the value weighted mean cost of issuing bonds (excluding the banking, finance, government and convertible bond issues, which is 20.6 basis points).

Using the conservative estimate of 9.1 basis points for benchmark underwriting fees and other annualised direct costs, and assuming that UED would require approximately four issues to fund its debt requirements over the regulatory period, we have derived a minimum benchmark debt raising cost of 11.8 bppa.

Table 9-5: Estimated debt raising cost for UED

Amount raised	1 issue	4 issues
	$200m	$800m
Gross underwriting fees (conservative)	9.1	9.1
Legal and road show @ $100,000 per issue	1.3	1.3

67 IBID.

Company credit rating ($50K)	0.7	0.2
Issue credit rating (3.5bp per median issue)	0.9	0.9
Registry fees	0.2	0.2
Paying fees	0.0	0.0
	12.2	**11.8**

Note: Annualised costs are based on an assumed cost of capital of 9.6 per cent. Amounts shown are in real 2010 terms.

9.9.3 UED's proposed debt risk premium

For the purpose of facilitating the calculation of a rate of return in this regulatory proposal, UED has adopted a debt risk premium of 471 basis points over the risk free rate. This margin does not include an allowance for debt raising costs which we have included in our forecast opex.

9.10 The value of imputation credits (gamma)

9.10.1 SORI requirement

The value of imputation credits (denoted by γ or "gamma") is determined as the product of two underlying parameters:

- the rate at which imputation credits are distributed to investors ("distribution rate", also represented by F); and
- the rate at which distributed credits are redeemed by investors ("utilisation rate", also represented by θ or theta).

The AER's recent WACC review adopted a value of 100 per cent for the distribution rate and 0.65 for the utilisation rate. Based on this, the SORI requires that a value of 0.65 be adopted in relation to the assumed value of imputation credits.

9.10.2 Persuasive evidence to depart from SORI requirement

The AER's review of WACC parameters noted that "a best estimate of gamma should be based on a market-wide estimate for businesses across the Australian economy".

In adopting a value of 0.65 for γ, the AER has relied upon the findings of a number of studies and advice from its consultants. These studies/advice are:

- advice from Handley that F should be set at 1.0;
- Beggs and Skeels (2006)[68] which estimates the value of θ at 0.57; and
- Handley and Maheswaran (2008)[69] which estimates the value of θ at 0.75.

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[68] **Beggs, D and C. Skeels, Market Arbitrage of Cash Dividends and Franking Credits, The Economic Record, 82(258), September 206, 239.**

The AER's final decision settled on a value for F of 1.0 based on the following specific considerations:

- analysis of the impact of the time value loss associated with the value of retained credits (which made certain assumptions about the proportion of credits retained each year and the appropriate rate for discounting imputation credits), which indicated that the loss is not so material that adopting a distribution rate of 1.0 is unreasonable; and
- based on advice from Handley (2009), adopting a distribution rate of 1.0 is consistent with the Officer framework (which is embodied in the building block framework), since this framework assumes that cash flows are distributed in full each period (i.e. there are no undistributed credits). Furthermore, it is consistent with the AER's post-tax revenue model which explicitly assumes a full distribution of free cash flows and avoids the need to address a range of other parameters (e.g. the value of retained credits distributed in a year subsequent to the year in which the credits were generated), the estimation of which is sufficiently uncertain.

Whilst UED has its reservations about the AER's decision to adopt a value of 1.0[70] for the distribution rate, this assumption is not in contention for the purposes of this submission. However, UED does have significant concerns about the AER's decision to set the value of θ ("theta" or the utilisation rate) at 0.65 reflecting the midpoint of a range of values set by the value of θ in Beggs and Skeels (2006) as the lower bound, and the value of θ in Handley and Maheswaran (2008) as the upper bound. These concerns are outlined below.

9.10.3 Estimation of the utilisation rate (θ)

The estimated value of θ in Beggs and Skeels (2006) cannot be interpreted as a lower bound value for θ. There is no basis for the AER to determine a point estimate for θ by averaging the results of Beggs and Skeels (2006) and Handley and Maheswaran (2008).

The AER's preferred point estimate of θ relies upon the results in Beggs and Skeels (2006) and Handley and Maheswaran (2008). Beggs and Skeels (2006) reported a point estimate for θ of 0.57, whilst Handley and Maheswaran (2008) reported an estimate of 0.74. Taken together, the point estimate in these two studies formed the basis for the AER's conclusion that the appropriate range of values for θ is from 0.57 to 0.74.

Each of these studies employ different methodologies to arrive at a point estimate for θ. It is a mere fact that one study produced a point estimate that was lower than the other. There is, however, no scientific justification upon which to infer from these studies that they each

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69 Handley, J and K Maheswaran, A measure of the efficacy of the Australian Imputation Tax System, The Economic Record, 84(264), March 2008.

70 The AER adoption of a payout ratio of 1.0 in its WACC Review is extreme because:

- **not all imputation credits are paid out; and**
- **not all imputation credits are paid out in the year that the credits are created, and therefore there is a time value loss for investors.**

Whilst quantification of the payout ratio may be difficult, it must be less than 1.0 for the above-mentioned reasons.

provide a lower and upper bound for the value of θ in the sense that one result is statistically significantly different from the other. This view is supported by Associate Professor Skeels' recent analysis of the AER's use of Beggs and Skeels (2006) to estimate a value for gamma[71].

> " … the estimate of Beggs and Skeels (2006) is not an estimate of a lower bound for γ (and hence θ) and it makes little sense to treat it as such … Given that the point estimate of 0.572 provided by Beggs and Skeels (2006) is evidently not an estimate of a lower bound to be used as such by the AER is completely unjustifiable."[72]

A more valid approach for estimating a lower bound value for θ using Beggs and Skeels (2006) would be to consider the standard error around the estimated value of θ. Associate Professor Skeels demonstrates that in Beggs and Skeels (2006), the point estimate of 0.57 had a standard error of 0.12. Therefore, the 95 per cent confidence interval for θ is between 0.33 and 0.81. If a lower bound value for θ is to be inferred from Beggs and Skeels (2006) it should be 0.33[73].

Additional empirical analysis on the value of θ using a larger data set and a more recent data period indicates that the value of θ is 0.23.

In setting the lower bound value of theta during the WACC review, the AER considered the analysis contained a study by the Strategic Finance Goup (SFG)[74] which was submitted by the Joint Industry Association during the AER's WACC review. This study aimed to replicate the analysis in Beggs and Skeels (2006) to test if the modified dividend drop-off methodology applied in Beggs and Skeels (2006) produces reliable results, and also to obtain results using more updated data. SFG's analysis was ultimately rejected by the AER and on this basis, the AER set the lower bound value of theta by reference to the results in Beggs and Skeels (2006):

> " 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."75

Since the release of the AER's final decision, the Victorian and South Australian electricity distributors have jointly commissioned Associate Professor Skeels (through solicitors Gilbert and Tobin) to provide an independent review of SFG's study and to assess the validity of

71 Skeels, C., Estimation of γ, Department of Economics, University of Melbourne, 18 June 2009.

72 IBID. Page 3, 5.

73 IBID. Page 7.

74 SFG Consulting, The value of imputation credits as implied by the methodology of Beggs and Skeels (2006), Report prepared for ENA, APIA.

75 AER Final Decision on WACC, page 447.

the grounds upon which the AER dismissed the results of the SFG study[76]. The important conclusion that Skeels (2009B) has drawn is that:

> " I find that the results presented in Appendix 1 constitute an empirically valid study of the dividend drop-off problem for Australia and that the SFG estimate of theta of 0.23 represents the most accurate estimate currently available."[77]

Skeels (2009B) notes that other than the AER's concerns about the lack of data scaling, SFG's use of Cook's D statistic for data filtering and SFG's use of incorrect tax rates:

> " Many of the criticisms raised by the AER were little more an allusions to potential problems with the SFG analysis. In some cases I found that these allusions were ill-founded and readily dismissed. In other instances, the appropriate response was to rework the model and to actually establish whether the concern was valid or not. This latter class of concerns was incorporated into the questions posed to SFG."[78]

To address the AER's concerns, Skeels (2009B) notes that SFG has reworked its analysis and these concerns have now been satisfactorily resolved as follows:

- in relation to data scaling that "…there is nothing in the results to suggest that the difference in scaling between the two studies has any significant impact on the results obtained."[79]. Nevertheless, Skeels (2009B) observes that a scaling adjustment has now been employed by SFG and concludes that "it is clear that the omission of this scaling factor in the SFG study was a minor issue"[80].
- in relation to data filtering that filtering "doesn't seem to matter very much…In my opinion as a matter of good statistical practice, one should go with the larger sample size unless there is reason to believe that there are problems with it. I have seen no compelling argument to believe that the larger sample sizes used by the SFG study should be dismissed as unreliable."[81] Skeels (2009B) observes that SFG has applied the same scaling used in Beggs and Skeels (2006) as well as added an additional layer of filtering. On this basis, Associate Professor Skeels considered that "SFG are now interrogating the data economically, as well as statistically, making their new results much more credible than their earlier results."[82]; and
- in relation to the use of incorrect tax rates that the error has been corrected by SFG and "it can be seen that the error was relatively small and had little impact."[83]

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[76] Skeels (2009B), Skeels, C.L., A Review of the SFG Dividend Drop-off Study, 28 August 2009.

[77] IBID. Page 5.

[78] IBID. Page 4.

[79] IBID. Page 17.

[80] IBID. Page 27.

[81] IBID. Page 21.

[82] IBID. Page 29.

[83] IBID. Page 4.

The important conclusion from Skeels (2009B) is that the most accurate estimate of theta is 0.23:

> " I find that the results presented in Appendix I constitute an empirically valid study of the dividend drop-off problem for Australia and that the SFG estimate of theta of 0.23 represents the most accurate estimate currently available.
>
> It is clear that the more recent data used in the SFG results presented in Appendix I favour an estimate of theta that is lower than that of 0.57 which was obtained by Beggs and Skeels on the basis of less recent data. However, it might be argued that the minor methodological differences that remain between the methodology of Beggs and Skeels (2006) and that of SFG bias their estimate of theta downwards. (This is not a position to which I subscribe and I present it only in the garb of a devil's advocate.) Were such a position to be taken then, in my opinion, a compelling case can be made that the empirical evidence overwhelmingly supports the notion that the true value of theta lies between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and that in all probability it lies closer to 0.23 than 0.57."[84]

UED considers that the views expressed by Associated Professor Skeels on the validity of the AER's criticisms of SFG's study, as well as his views on SFG's revised results, provide persuasive new evidence on the value of theta, and demonstrates that the AER has incorrectly dismissed the results of SFG's study. The revised SFG study results, which now address the most significant concerns raised by the AER in its draft decision, indicates that a reasonable value for θ is 0.23.

9.10.4 UED's proposed value of imputation credits

UED considers that there is persuasive new evidence presented in this submission to support revisiting the value for gamma. UED considers that the value for θ lies within a range of 0.23 to 0.74. Assuming a distribution rate of 1.0, this implies that the appropriate value for γ is also between 0.23 and 0.74, and applying "equal weight" to both the revised SFG study which has been independently reviewed by Associate Professor Skeels and Handley and Maheswaran (2008) as the AER did in the SORI review, suggests that a reasonable point estimate for the value of imputation credits is around 0.5.

9.11 The value of imputation credits (gamma)

9.11.1 Persuasive evidence to depart from SORI requirement

This new evidence is provided by an independent review by Associate Professor Skeels[85], of matters relating to the estimation of the value of theta. The review was commissioned following the publication of the AER's WACC final decision.

Associate Professor Skeels' review demonstrates that there has been a material change in circumstances in relation to the estimation of the value for gamma, since the publication of the SORI. The report of Associate Professor Skeels' independent review is provided as an appendix to this Regulatory Proposal.

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[84] **IBID. Page 5.**

[85] **Christopher L Skeels, A Review of the SFG Dividend Drop-Off Study: A Report prepared for Gilbert and Tobin, 28 August 2009**

Associate Professor Skeels revisited the SFG report entitled *The value of imputation credits as implied by the methodology of Beggs and Skeels (2006)*, and the criticisms made of that report by the AER in its WACC final decision. Associate Professor Skeels' findings are summarised below:

- The essential feature of the AER's analytical approach is the use of a regression-based methodology focusing on the post 1 July 2000 period. The SFG study adopts the same broad strategy.
- In response to questions put to SFG by Associate Professor Skeels regarding scaling and filtering of data, SFG now provides results:
    - that allow greater comparability with the results of Beggs and Skeels (2006); and
    - that are much more credible than those presented in the SFG study lodged during the AER's WACC review.
- The Beggs and Skeels (2006) study - which was relied upon by the AER - employs data to 10 May 2004 while the SFG study uses data for the period up to 30 September 2006. The SFG study extends the sample period to include an additional 28 months of data in the post-2000 sub-sample. This represents an important contribution by the SFG study. In particular, by extending the study period, more information is available for use in estimation and, all things equal, one would expect the estimates obtained in the SFG study to more accurately reflect the true population values than do those provided by Beggs and Skeels (2006) on the basis of a smaller sample.
- The SFG study estimates of theta are of equal significance as those of Beggs and Skeels (2006).

Page 5 of Associate Professor Skeels' independent report proceeds to note the following key findings:

> "I find that the results presented in Appendix I constitute an empirically valid study of the dividend drop-off problem for Australia and that the SFG estimate of theta of 0.23 represents the most accurate estimate currently available.
>
> It is clear that the more recent data used in the SFG results presented in Appendix I favour an estimate of theta that is lower than that of 0.57 which was obtained by Beggs and Skeels on the basis of less recent data. However, it might be argued that the minor methodological differences that remain between the methodology of Beggs and Skeels (2006) and that of SFG bias their estimate of theta downwards. (This is not a position to which I subscribe and I present it only in the garb of a devil's advocate.) Were such a position to be taken then, in my opinion, a compelling case can be made that the empirical evidence overwhelmingly supports the notion that the true value of theta lies between the SFG estimate of 0.23 and the Beggs and Skeels (2006) estimate of 0.57, and that in all probability it lies closer to 0.23 than 0.57."

The evidence presented in Associate Professor Skeels' independent report is new evidence that was not taken into account by the AER in its recent WACC review. The circumstances relating to the AER's estimate of the value of gamma have changed to the extent that data that was given limited weight by the AER has now been reworked with the assistance of Associate Professor Skeels, and is shown to be the best available data on which an estimate of theta should be based. Importantly, this new evidence is presented by a co-author (Associate Professor Skeels) of the study that the AER had relied upon in determining the lower bound value of theta for the purpose of estimating gamma in the SORI.

9.11.2 UED's proposed gamma value

As noted above, the AER expressed some concerns with, and placed limited weight on the SFG study. In relation to that study, page 447 of the AER's WACC final decision states:

> "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".

The independent report of Associate Professor Skeels confirms that the SFG study adopts an analytical approach (namely, the use of a regression-based methodology focusing on the post 1 July 2000 period) which is consistent with that referred to by the AER in its WACC final decision. Associate Professor Skeels' report also notes that once SFG's analysis had been reworked to address the concerns expressed by the AER, the SFG analysis provides an estimate of theta of 0.23, which represents the most accurate estimate currently available. Explicitly, Associate Professor Skeels expresses a preference for the revised SFG estimate compared to the report that he co-authored and which the AER relied upon in its WACC final decision.

The reasoning set out in the AER's WACC final decision suggests that the principal underlying criteria on which that decision was based include: statistical rigour, independent verification, methodological rigour, and the use of the largest available data set for the post July 2000 period. The analysis and opinions presented by Associate Professor Skeels in his independent report address these criteria.

This new evidence:

- constitutes persuasive evidence that 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 submits 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.

Accordingly, applying the methodology adopted by the WACC final decision to select a point estimate of gamma results in a gamma value of 0.5.

Based on the evidence presented above and in the relevant accompanying appendices, UED proposes, pursuant to Clause 5.5.4(g) of the Rules, that a gamma value of 0.65 should not be adopted for the forthcoming regulatory control period, and instead, a value of 0.5 should be adopted.

The gamma value of 0.5 is the product of:

- the imputation credit payout ratio (F), which is 1.0 for the purpose of this Regulatory Proposal; and

the market value of imputation credits actually distributed theta, which is 0.5.

10. Other Building Block Elements

Key messages

- 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.

10.1 Regulatory requirements and chapter structure

The ESCV published its Final Determination for the 2006-2010 electricity distribution price review in October 2005. In this Final Determination, the ESCV set out incentive arrangements that should apply in relation to service improvements (the S-factor scheme) and operating cost efficiencies (the ECM). Since the publication of this determination, responsibility for regulating the Victorian distribution businesses has transferred from the ESCV to the AER, and the businesses will now be regulated in accordance with Chapter 6 of the Rules.

The AER has recognised the importance of honouring the ESCV's incentive schemes. This approach provides certainty to the businesses and credibility to the regulatory regime – a point that was noted by ESCV's predecessor, the Office of the Regulator-General, when the ECM was first established in September 2000. In its final distribution determination, the ORG noted that:

> " The Office recognises that to the extent there is uncertainty regarding the adoption of the post-2001 incentive mechanism outlined in this Determination, the incentive properties of the mechanism will be reduced. For this reason, the Office is now setting out in some detail what it considers to be the appropriate mechanics for applying the long-term carryover mechanism. This is intended to provide a clear and stable framework within which the distributors can make future expenditure decisions. The long-term carryover mechanism has been designed with the objective of making it transparent, easy to administer and replicable from one regulatory period to the next. These features enhance the credibility of the Office's commitment to implementing the mechanism in the future." [86]

In its Framework and Approach Paper, the AER made the following comments in respect of the S-factor and ECM schemes

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[86] **Office of the Regulator-General, Electricity Distribution Price Determination 2001-2005, Volume I, September 2000, page 87.**

> " In response to SP AusNet's submission on the interaction between the ESCV scheme and the AER STPIS, the AER notes that benefits and penalties accrued in the current regulatory control period under the ESCV scheme will not be incorporated in the price cap formula. Rather, financial carryover amounts from the current regulatory control period will be included as a building block element in the calculation of allowed revenue for the next regulatory control period."

> " 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." [87]

In addition to these statements, clauses 10.1(a)(iv) and (v) of the RIN requires that:

> " all carryover amounts (accrued under the ESC's efficiency carryover mechanism) for each regulatory year of the current regulatory control period calculated in accordance with:
>
> (1) the growth adjustment formula in the EDPR;
>
> (2) the principles on changes to capitalisation policy contained in the EDPR; and
>
> all carryover amounts which have not been calculated in accordance with paragraphs 10.1(a)(iv)(1) and 10.1(a)(iv)(2)."

Clause 10.2 of the RIN further requires that the carryover amounts referred to in clause 10.1(a)(iv) are explained and that any relevant models, documents, or spreadsheets used in the calculation of these carryover amounts are provided to the AER. In accordance with these RIN requirements, UED can confirm that the calculation of the ECM presented in this Chapter is consistent with the ESCV scheme and the capitalisation policy that applied in the EDPR. UED will provide the supporting models and spreadsheets to the AER in accordance with the RIN requirements.

In accordance with the AER's Framework and Approach Paper and the RIN, the remainder of this Chapter is structured as follows:

- Section 10.2 describes the additional revenue for the forthcoming regulatory period to which UED is entitled in accordance with the ESCV's S-factor scheme which operated during the current regulatory period; and
- Section 10.3 describes the additional revenue for the forthcoming regulatory period to which UED is entitled in accordance with the ESCV's ECM scheme which operated during the current regulatory period.

10.2 S-Factor

UED is subject to a tariff basket price formula for the 2006-10 period, which is of the form:

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[87] **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.**

$$(1+CPI_t)(1-X_t)L_tS_t$$

The 2005 Electricity Distribution Price Determination, Volume II defines these elements of the price control as follows[88]:

- CPIt is defined in attachment 1 of the determination;
- Xt is as set out in clause 2.3.8 of the determination;
- St is the S-factor determined in accordance with clause 2.3.9 of the determination; and
- Lt is the licence fee pass through adjustment determined in accordance with clause 2.3.15 of the determination.

The s-factor formulae contain a number of complex features, which are explained more fully in Appendix H-1 which discusses the close-out of the current ESCV service target incentive scheme. For the purpose of explaining the 2005 determination more fully, UED believes that it is necessary to draw attention to the decomposition of the St term as shown below:

$$S_t = \frac{\left(1+S_t^{'}\right)}{\left(1+S_{t-6}^{'}\right)}$$

In the numerator in the above equation, $\left(1+S_t^{'}\right)$ reflects the relative improvement or deterioration in service performance in the most recent year for which data is available, compared to the previous year. Given the timing issues in relation to data availability, the term $\left(1+S_t^{'}\right)$ compares service performance two years prior to year t, relative to service performance in the previous year (i.e. three years prior to year t). Therefore, the calculation of the numerator in the ESCV's S-factor scheme cannot be finalised until 2012.

The denominator in the above equation, $\left(1+S_{t-6}^{'}\right)$, has the effect of reversing the bonus or penalty payment made six years earlier. The purpose of the denominator is to give effect to the ESCV's view that service performance bonuses or penalties should be retained for six years. The ESCV explained the purpose of the term $\left(1+S_{t-6}^{'}\right)$ as follows:

> " The Commission notes that [rather than introducing a penalty] the S_{t-6} removes a reward after 6 years. Additionally, the Commission notes that any decisions made by the distributor to improve performance during the current period, and thereby receive a reward through an increase in average prices paid by customers, would have been made with the knowledge that this reward only applied for 6 years."[89]

It follows from the above description of the S-factor scheme that there are two elements which need to be considered in giving effect to the ESCV scheme, in accordance with the AER's Framework and Approach Paper:

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[88] **Essential Services Commission, Electricity Distribution Price Review, Final Decision Volume 2 Price Determination, October 2005. Pages 12 and 13.**

[89] **ESCV (2005a). Electricity Distribution Price Review, 2006-10. Final Decision, Volume 1, Statement of Purpose and Reasons. Essential Services Commission. October 2005. Page 99.**

1. UED's service performance for years 2009 and 2010 should be subject to the S-factor scheme. An estimate of UED's 2009 performance, based on nine months of actual data, has been adopted. In addition, for the purposes of this Regulatory Proposal, UED has estimated its performance in 2010 on the assumption that reliability-of-service and customer service measures will progress gradually towards the average level of performance achieved from 2005 to 2009.

2. The financial impact of the term $\left(1+S_{t-6}^{'}\right)$ will need to be taken into account. The six year lead-time in applying this term means that bonus or penalty payments in, for example, 2011 (which relate to performance in 2009) will be reversed in 2017.

UED proposes that for the purposes of 2011 tariffs the performance of 2003 and 2009 should be included in the current formulation. The 2012 tariffs should include a finalisation adjustment for the close out of the current schemes (i.e. 2010 performance). 2013 will be the first year where tariffs will include an adjustment for actual performance under the new scheme – i.e. for 2011 performance. The rounding off of the current scheme is discussed in appendix H-1

10.3 Efficiency carryover mechanism

UED has been subject to an efficiency carry-over mechanism (ECM) from 2006 to 2010. The scheme was devised by the Office of the Regulator-General for application over the 2001 to 2005 regulatory period, and then maintained by the ESCV from 2006 to 2010. The ECM is essentially an arrangement for sharing efficiency gains between distributors and their customers. An efficiency gain is a reduction in operating expenditure in any one year relative to forecast. The apportioning of the gains occurs because distribution businesses retain the savings from any under-spending within the regulatory period, but then participate in the transfer of these benefits to customers in the following regulatory period through lower projected levels of operating spending (and therefore lower prices).

A key component of the scheme, which ensures that customers receive their share of efficiency benefits, is the translation of revealed costs into forecasts. Distributors are also rewarded by being able to earn efficiency carry-over amounts in the subsequent regulatory period. The ECM is based on an incremental calculation method which was designed to ensure that rewards are only retained where efficiencies are sustainable.

In Volume I of the Final Decision, (ESCV 2005a), the ESCV stated that efficiency carry-over amounts would 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 context is interpreted to be the under-spend (or over-spend) between forecast and actual in year one, and then the incremental under-spend (or over-spend) in subsequent years.

UED has applied the calculation method to its forecast and actual figures for operating and maintenance (O&M) expenditure from 2006 to 2010. The results of the evaluation are presented below in Table 10-1. The dollar amounts for both benchmark and outturn components have been escalated to give values in 2010 prices. The savings in O&M expenditure resulting from efficiency improvements implemented by UED are shown in the table. The incremental change from one year to the next is also presented. The forecast incremental change for 2010 has been zero rated at this juncture.

Table 10-1: Efficiency carryover mechanism calculation for 2006-2010

	2006 $M	2007 $M	2008 $M	2009 $M	2010 $M
O&M benchmark	95.9	97.9	99.9	102.1	101.8
Growth adjustment	0.2	0.5	0.7	0.9	1.2
O&M Actual	92.9	87.6	90.0	93.8	96.0
Under-spend/(Over-spend)	3.2	10.8	10.6	9.2	6.9
Incremental efficiency gains	3.2	7.6	- 0.2	-1.4	-

Amounts shown in real 2010 terms.

Source: UED calculations and financial model for EDPR 2011 to 2015. Methods outlined in section 4.2, ESCV (2004a)[90] and chapter 10, ESCV (2005a). The 'incremental efficiency gain' is the change in under or over-spending from one year to the next. No incremental gain or loss is shown for 2010 because actual O&M figures are not yet available (estimates are shown).

The incremental change for 2010 is shown as being zero, because the out-turn figures for O&M spending are clearly not available at this stage. The numbers for actual O&M spending in 2010 are estimates drawn from the UED regulatory model.

It will not be possible to calculate the incremental change accurately for 2010 in the middle of the next calendar year. However, UED expects that it will provide a revised non-zero estimate. To the extent that this estimate turns out to be inaccurate or incorrect, UED suggests that a correction factor be applied during the forthcoming regulatory period, from 2011 to 2015.

Table 10-1 includes a growth adjustment in accordance with the ESCV scheme. The growth adjustment removes the effects of differences between forecast and actual growth in maximum demand and energy. In this way, the ECM rewards genuine improvements in cost performance, rather than cost differences that arise from forecasting errors. The calculation of the growth adjustment is explained in further detail later in this section.

The ECM provides for the 'incremental efficiency gains' in each year to be carried over for five years. The efficiency carryover amount in any year in the next regulatory period is the sum of the carryover amounts for that year from the previous regulatory period, as shown in Table 10-2 below. For example, the incremental efficiency gain in 2006 only occurs in year 2011 (five years hence); whereas the incremental gain for 2007 occurs in years 2011 and 2012; and the incremental gain for 2008 occurs in years 2011; 2012 and 2013. The carryover amount for 2012, for example, is therefore the sum of the individual incremental gains for years 2007; 2008; 2009 and 2010 (noting that the incremental gain for 2010 is assumed to be zero).

90 ESCV (2004a). Final Framework and Approach: Volume 1, Guidance Paper. Electricity Distribution Price Review 2006. Essential Services Commission, Victoria. June 2004.

Table 10-2: Assessed carry-over values from EDPR 2006 to 2010

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.

The growth adjustment is calculated in accordance with the following equation, which was developed during the ESCV's 2006-2010 electricity distribution price review.

Growth adjustment = PFP coefficient weightings × percentage change in growth

$$\begin{aligned} Growth\ adjustment = \ & 0.431 \times (\log natural\ change\ in\ customers) + \\ & 0.272 \times (\log natural\ change\ in\ peak\ demand) + \\ & 0.296 \times (\log natural\ change\ in\ energy\ consumption) \end{aligned}$$

Where:

- 0.431 is the PFP coefficient weighting associated with customer numbers.
- 0.272 is the PFP coefficient weighting associated with peak demand.
- 0.296 is the PFP coefficient weighting associated with consumption.

The use of logarithms when measuring the growth in a variable value from one period to the next is necessary because the empirical work undertaken by PEG[91] was based on the estimation, using econometric methods, of a transcendental logarithmic function.

The ESCV stipulated that the growth adjustment coefficient should only be applied to the base component of the O&M expenditure projections and not to figures which would be net of step changes. UED has followed the ESCV's approach to adjusting benchmark O&M forecasts for the purpose of calculating the allowed efficiency carryover. The result obtained for the growth adjustment factor is -0.539 per cent. A negative value is reported because peak demand for electricity increased more strongly than expected over the period from 2006 to 2009. The higher than expected peak demand has a positive effect on the

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[91] **PEG (2004). Predicting growth in SPI's O&M expenses. A report prepared for SP Ausnet by Pacific Economics Group, LLC. 13 October 2004.**

efficiency carryover amount as, other things being equal, the benchmark O&M expenditure would have been higher if the higher than expected demand had been anticipated.

As noted in section 10.2 above and in accordance with the RIN, UED will provide the relevant models and spreadsheets used in the calculation of these carryover amounts to the AER. A further explanation of the ECM and the growth adjustment mechanism put forward by the ESC is provided in appendix H-5

11. Total revenue and X factor

Key messages

- 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.

11.1 Regulatory requirements and chapter structure

This Chapter summarises UED's building block proposal, its proposed X factor and its indicative prices for direct control services. In providing this information UED complies with clauses 6.4.3, 6.5.9, and 6.8.2 of the Rules. Each of these clauses is discussed in turn.

Clause 6.4.3 of the Rules requires that the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks are:

- indexation of the regulatory asset base;
- a return on capital for that year;
- the depreciation for that year;
- the estimated cost of corporate income tax;
- the revenue increments or decrements (if any) for that year arising from the application of the efficiency benefit sharing scheme, the STPIS and the demand management incentive scheme ("DMIS");
- the other revenue increments or decrements (if any) for that year arising from the application of a control mechanism in the previous regulatory control period; and
- the forecast operating expenditure for that year.

Clause 6.5.9 of the Rules requires that a building block determination is to include the X factor for each control mechanism for each regulatory year of the regulatory control period. It further requires that the X factor:

- must be set by the AER with regard to the DNSP's total revenue requirement for the regulatory control period; and
- must be such as to minimise, as far as reasonably possible, variance between expected revenue for the last regulatory year of the regulatory control period and the annual revenue requirement for that last regulatory year; and
- must conform with whichever of the following requirements is applicable:

- o if the control mechanism relates generally to standard control services – the X factor must be designed to equalise (in terms of net present value) the revenue to be earned by the DNSP from the provision of standard control services over the regulatory control period with the provider's total revenue requirement for the regulatory control period;
- o if there are separate control mechanisms for different standard control services – the X factor for each control mechanism must be designed to equalise (in terms of net present value) the revenue to be earned by the DNSP from the provision of standard control services to which the control mechanism relates over the regulatory control period with the portion of the provider's total revenue requirement for the regulatory control period attributable to those services.

In addition to the above requirements, clause 6.8.2(c)(4) of the Rules requires a DNSP to present indicative prices for direct control services for each year of the forthcoming regulatory period.

In light of these regulatory requirements, the remainder of this Chapter is structured as follows:

- Section 11.2 summarises the building block components for each year of the forthcoming regulatory period;
- Section 11.3 presents UED's proposed X factor; and
- Section 11.4 presents indicative prices for direct control services.

11.2 Annual building block revenue requirement

Table 11-1 below provides a summary of the composition of the unsmoothed building block revenue requirement for the forthcoming regulatory period.

Table 11-1: 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.

As provided for in chapter 16 the current STPIS will end and be replaced by a new national scheme. UED notes that rewards and penalties for the current scheme are still required to be calculated in accordance with current regulatory arrangements.

Actual performance for 2009 and 2010 would not be calculated until 2011 and 2010 respectively. In addition the t-6 component of the formula would also not finalise until 2018. UED would prefer to include an adjustment factor to the tariff formula for 2012 to finalise the current scheme rather than provide a building block component of revenue. This will ensure that all data is known and no estimates or further true-ups are required in order to close the current scheme. However for the purposes of complying with the AER's Framework and Approach paper UED has presented the S-factor estimate in the building block proposal.

11.3 X Factor

An "X" factor of 4.0 per cent has been chosen 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 is consistent with the approach previously adopted by UED and consistent with the Rules.

Table 11-2: Annual X Factor amounts

	2011	2012	2013	2014	2015
Annual X Factor	-16.6%	-4.0%	-4.0%	-4.0%	-4.0%

The x factors provided in the table above have been applied to the forecast 2010 prices. Indicative prices for each tariff are included in chapter 14.

11.4 Analysis of typical customer/pricing outcomes

A typical electricity bill will comprise four components. These being:

- the cost of power (generation);
- the cost of transportation (transmission);
- the cost of distribution (distribution); and
- billing (Retail costs)

This regulatory proposal is based on the distribution component of an electricity invoice. A summary of a typical residential bill is provided in Table 11-3 below:

Table 11-3: Analysis of '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	16.6%
Retail	$ 360.00	$ 360.00	0.0%
AIMRO	$ 70.00	$ 70.00	0.0%

	Current invoice (2010)	New invoice (2011)	% Change
Total Invoice	**$ 1,020.00**	**$ 1,068.00**	**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.

12. Service Classification

Key messages

- 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.

12.1 Regulatory requirements and chapter structure

The classification of services determines the manner in which a DNSP recovers the costs associated with the distribution services it provides. For example, the costs of providing standard control services will be recovered through DUOS tariffs paid by all customers whereas the costs of providing alternative control services and negotiated distribution services would be recovered from individuals who specifically request the service.

Section 6.8.2(c)(1) of the Rules, requires UED's regulatory proposal to include:

- a classification proposal showing how the distribution services to be provided should be classified; and
- if the proposed classification differs from the classification suggested in the relevant framework and approach paper – include the reasons for the difference.

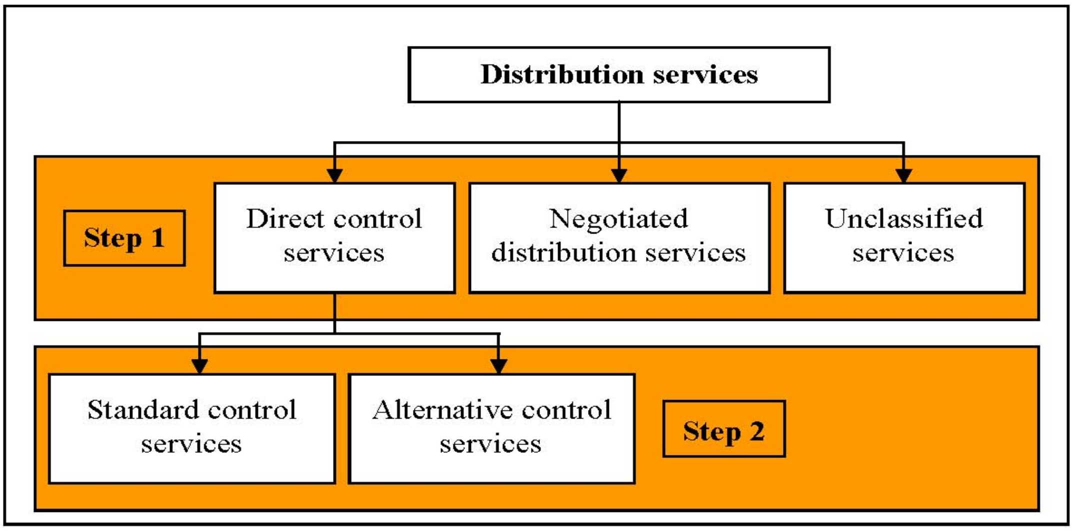
Section 6.2.1(d) states that in classifying services that have previously been subject to regulation under the present or earlier legislation the AER must act on the basis that unless a different classification is clearly more appropriate:

- there should be no departure from a previous classification (if the services have been previously classified); and

- if there has been no previous classification – the classification should be consistent with the previous applicable regulatory approach.

Figure 12-1 below has been extracted from the AER's Framework and Approach paper and outlines the steps in the distribution service classification process.

Figure 12-1: Distribution service classification process



In view of these requirements, the remainder of this chapter is structured as follows:

- Section 12.2 provides an overview of the AER's proposed classification of services;
- Section 12.3 presents UED's comments on the AER's proposed classification; and
- Section 12.4 presents UED's proposal regarding classification of services.

12.2 AER's proposed classification of services

The AER's proposed classification of services is provided in Table 12-1 below:

Table 12-1: AER's Proposed classification of services

AER Service Group	AER Likely Classification	Service/Activity
Network services	Standard control service	• Constructing the distribution network • Maintaining the distribution network and connection assets • Operating the distribution network and connection assets for DNSP purposes • Planning the distribution network • Designing the distribution network • Emergency response • Administrative support (e.g. call centre, network billing)
Connection Services	Alternative control service	• Energisation of new connections
	Negotiated distribution service	• Connection and augmentation works for new connections • Connection and augmentation works for new connections
Metering services	Alternative control service	• Metering data provider services for unmetered supplies with Type 7 metering installations
Public lighting services – operation, repair, replacement and maintenance of DNSP public lighting assets	Alternative control service	• Operation, repair, replacement and maintenance of DNSP public lighting assets
Public lighting services – alteration and relocation of DNSP public lighting assets	Negotiated distribution service	• Alteration and relocation of DNSP public lighting assets
Public lighting services – new public lighting	Negotiated distribution service	• New public lighting
Quoted services	Alternative control service	• Rearrangement of network assets at customer request, *excluding* alteration and relocation of existing public lighting assets • Supply enhancement at customer request • Emergency recoverable works (i.e. emergency works where customer is at fault and immediate action needs to be taken by the DNSP) • Auditing of design and construction • Specification and design enquiry fees

AER Service Group	AER Likely Classification	Service/Activity
Fee based services	Alternative control service	• De-energisation of existing premises • Re-energisation of existing premises • Temporary disconnect/reconnect services • Temporary supply services • Wasted attendance – not DNSP fault • Service truck visits • Location of underground cables • Elective underground service where an existing overhead service exists • Covering of low voltage mains for safety reasons • Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh • Supply abolishment • Fault response – not DNSP fault • Damage to overhead service cables caused by high load vehicles • High load escorts – lifting overhead lines
Unregulated services	Not classified	• All "metering provider services" other than as detailed above • All "metering data provider services" other than as detailed above • Installation and maintenance of watchman (security) lights

12.3 UED's comments on AER's proposed classification

In its Framework and Approach Paper, the AER concluded that its likely approach is that standard and non-standard connection and augmentation works 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.

Whilst the framework paper is not binding on the AER or UED, clause 6.12.3(b) of the Rules provides 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 Regulatory Proposal and the submissions received, there are good reasons for departing from the classification proposed in the framework paper.

UED submits that there are good reasons for departing from the classification proposed in the AER's Framework and Approach Paper as set out below.

12.3.1 Application of the regulatory framework

There is no service for connection and augmentation works for new customer connections that is capable of classification separately from the network services that the AER proposed be classified as standard control services.

A distribution service is defined as a service provided by means of, or in connection with, a distribution system. A distribution system is defined as a distribution network together with the connection assets associated with the distribution network. Notably, connection assets on their own do not constitute a distribution system.

Connection and augmentation works for new customer connections constitute an aspect of the distribution system which is used to provide network services. These network services the AER has properly proposed be classified as standard control services.

Put alternatively, new connection and augmentation assets are simply assets that from a part of the distribution system that is used to provide standard control services. New connection and augmentation works are not a separate *service* capable of classification.

However, if they were such services, they would be properly characterised as standard control services as they are services going to the construction of the distribution network.

12.3.2 Departure from previous approach

Under clause 6.2.1(d) of the Rules, in classifying distribution services that have previously been subject to regulation, the AER must act on the basis that unless a different classification is clearly more appropriate:

- there should be no departure from a previous classification (if the services have been previously classified); and
- if there has been no previous classification – the classification should be consistent with the previously applicable regulatory approach.

The AER's classification of new customer connection and augmentation works as negotiated distribution services is inappropriately inconsistent with the previously applicable regulatory approach.

Current Victorian regulatory arrangements

The current Victorian regulatory approach is that network services are priced so that:

(a) the capital cost of new works and augmentation is partially recovered from the customer (i.e. the customer's capital contribution towards the capital cost of that work calculated in accordance with ESC Guideline No. 14); and

(b) the balance of the capital cost (i.e. the balance of the capital cost of undertaking the new work and augmentation after deducting the customer's capital contribution) is recovered via the payment for DUOS charges (i.e. charges for prescribed distribution services).

AER acknowledgement of departure

On page 38 of the framework paper, the AER states that:

> " classifying connection and augmentation works as negotiated distribution services under the NER will result in the capital cost of those services being recovered under the negotiate/arbitrate framework set out in chapter 6 of the NER, rather than through DUOS charges for network services under the building block model."

These comments by the AER recognise that under the previous regulatory approach some of the capital costs of the new customer connection and augmentation works:

- were being recovered through DUOS charges (now classified by the AER as charges for standard control services); and
- were being recovered through an excluded service charge.

Virtues of the current classification

UED considers the current approach together with the application of the principles of ESC Guideline No. 14 best achieves whole of network efficiency objectives by basing customer contributions on recovering any shortfall between the incremental revenue expected from a customer and the incremental cost expected from providing the service. Under this approach, the purpose of customer contributions is to ensure that customers expect to pay at least the net incremental cost of providing their service by reference to:

- the present value of the expected stream of distribution tariffs over the expected life of the customer's connection; and
- the incremental cost of providing network services to that customer, including the impact of that customer's connection on the timing of future augmentations to the network.

12.3.3 Recovery of past capital expenditure

As outlined above, UED's view is that assets arising from new connection and augmentation works are simply assets that are used to provide standard control services. Accordingly, for the purposes of clause 6.5.1(a) and S6.2.1(e)(4), UED has rolled into the opening RAB for 2011 that net capital expenditure (i.e. the balance paid by UED after deducting the customers' capital contributions) for new customer connection and augmentation works during the current regulatory control period.

If, however, there is a separate service that can be classified and the AER classifies it as a negotiated distribution service and as a consequence clause S6.2.1(e)(4) of the Rules operates so that the net capital expenditure for new customer connection and augmentation works during the 2006-2010 regulatory control period could not be included in the opening RAB on 1 January 2010, this would be cause for a classification as standard control services.

As that expenditure could otherwise not be recovered because the current Victorian regulatory arrangements have prohibited, and will continue to prohibit, UED from recovering the net capital expenditure from the customer, rejecting a classification that operated to deny expenditure incurred in good faith (and instead adopting a classification of standard control services that would allow recovery of that expenditure) would be a relevant matter for the AER under clause 6.2.1(c)(2) and (3) and would be consistent with the national electricity objective and the revenue and pricing principles.

12.3.4 Conclusion

The AER's likely approach is inconsistent with the regulatory framework and departs from a relevant previous approach. That different classification is not clearly more appropriate 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.

12.4 UED proposal regarding classification of services

UED proposes 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.

Alternatively, UED proposes that the service be classified as a standard control service.

In either case, as a pricing matter, 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.

13. Energy, peak demand and customer number forecasts

Key messages

- UED and NIEIR have a good track record of forecasting energy volumes as indicated by the accuracy of the forecasts for the 2006-2010 regulatory period.
- UED's energy sales volumes have declined over the current regulatory period (2006-2009, demonstrating (among other things) the success of energy efficiency initiatives), and this decline is expected to continue given the effects of:
  - climate change;
  - government policies aimed at increasing energy efficiency and reducing usage; and
  - the introduction of AMI meters, which enable customers to monitor and control consumption.
- Customers will migrate to time of use tariffs as interval meters are installed – this will change their usage profile from total usage to time of day usage;
- Customers will switch usage from peak to off-peak periods;
- Micro generation will continue to develop in response to government incentives to install solar panels; and
- Public lighting usage will decline as the volume of energy efficient lighting continues to increase.
- 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 that while customers may be consuming less for 360 days of the year, they are not prepared to go with their air conditioning on the hottest days, and their appetite for air conditioning is growing at a rapid rate.
- 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.

13.1 Rules requirements and chapter structure

Chapter 4 of this Regulatory Proposal provides an overview of forecast load growth, peak demand and customer numbers, which are important drivers for UED's capital and operating expenditure forecasts, noting in particular that clause S6.1.1(3) of the Rules requires the following information to be included in a Regulatory Proposal:

> " the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth."

UED's forecasts have been developed with the assistance of NIEIR. NIEIR are experts in the field of load forecasting and are also engaged by AEMO to forecast load for Victoria. In NIEIR's report for UED, which is provided as an appendix to this Regulatory Proposal, NIEIR reconciles its forecasts for UED with AEMO's load forecasts for Victoria. This reconciliation provides further confidence that UED's load forecasts provide a sound foundation for forecasting its capital expenditure requirements.

In addition to engaging NIEIR, UED asked AECOM to provide expert advice on the likely effects of climate change on UED's future load. AECOM's report is attached to this Regulatory Proposal and has been referenced by NIEIR in determining UED's load forecast.

In light of the Rules requirements, the remainder of this Chapter is structured as follows:

- Section 13.2 compares UED's forecast and actual energy volumes for the current regulatory period;
- Section 13.3 describes UED's forecasting methodology and examines the key factors that will affect the forecasts for the forthcoming regulatory period.
- Section 13.4 presents describes and discusses UED's maximum demand, energy and customer number forecasts for the forthcoming regulatory period.
- Section 13.5 summarises UED's forecasts for energy, maximum demand and customer numbers.

13.2 Forecast and actual energy volumes for the current period

Table 13-1 below provides a comparison between actual and forecast energy (and estimated usage for 2009 and 2010).

Table 13-1: Comparison of actual load to the 2006 EDPR benchmark load – GWh's

Year Ending 31 December					
Category	**2006**	**2007**	**2008**	**2009**	**2010**
Actual/forecast energy	7,814	7,888	7,912	7,814	7,788
2006 EDPR forecast	7,665	7,817	7,943	8,046	8,161
Variance	149	71	- 31	- 232	- 373

Total energy forecast for the five year period is 39,632 GWh compared to actual (and estimated) usage of 39,217 GWh, a variance of only 415 GWh or approximately 1 per cent. This data demonstrates that UED and NIEIR have a good forecasting track record.

However, it is also noted that the actual load has been lower than forecast, and has actually declined over the course of the regulatory period. The stagnation 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.

The data contained in Table 13-1 demonstrates that:

- UED has experienced a decline in energy sales volumes over the regulatory period; and
- UED's and NIEIR have a good track record in forecasting load and energy.

Energy growth over the five period has declined. This is a reflection of UED's territory that has the lowest customer growth amongst the five Victorian distribution businesses.

13.3 Methodology and factors affecting UED's forecasts

13.3.1 Overview of forecasting methodology

Figure 13-1 provides an overview of UED's forecasting methodology as a flowchart.

Figure 13-1: UED's forecasting methodology

Historical Data	Historical data is reviewed to determine if it contains events that are not re-occurring or other events that may affect forecasts. Historical data is weather normalised to smooth out the effects that weather has on usage so that the underlying usage and historical growth patterns can be determined. Historical data is provided to NIEIR to update their state-based model and provide a longer time series of data
Economic Forecasts	NIEIR consolidate all federal and state-based forecasts to determine sales forecasts. NIEIR apply these economic forecasts on an industry by industry basis and apply those to the UED territory based on regional information contained in their database.
Climate Change & other Government Policies	There are a number of federal and state based policies and initiatives aimed at reducing green house emissions, which have been captured by NIEIR and AECOM in their modelling. These policies will reduce load over the 2011 – 2015 period.
AIMRO rollout and tariff migration	UED has begun the roll-out of AIMRO meters as directed by the Victorian Government and legislated in an Order in Council. To date there has been no migration of customers due to a lack of IT infrastructure and the ability to invoice time-of-use tariffs. UED has time-of-use tariffs in place and ready for billing when the new IT systems are available (approx June 2010). In order to realise the benefits of AMI metering UED intends to migrate consumers onto time-of use tariffs during 2010. As a result, a component of a customer's current usage will be billed at a cheaper off-peak rate.

Effect of AIMRO information	Once consumers receive ½ hourly metering data it will empower them to further shift load to cheaper periods (price elasticity). The price elasticity effect is included in the NIEIR report.
Micro Generators	Micro generation, in particular photovoltaic cells, will have a growing impact on network load, Government subsidies and the availability of rebates for those generating electricity back into the grid will encourage installation. An increasing number of consumers are expected to take advantage of these technologies and subsidies in the 2011-2016 period.

Further details are contained in NIEIR's report, which is included as an appendix to this submission.

13.3.2 Key features of UED's region

UED's customers are located in Melbourne's south-eastern suburbs and the Mornington Peninsula. In terms of ABS statistical regions and Local Government Areas (LGAs) it includes:

- Bayside;
- Frankston (part);
- Glen Eira;
- Greater Dandenong;
- Kingston;
- Manningham;
- Monash;
- Mornington Peninsula;
- Port Phillip (part);
- Stonnington (part); and
- Whitehorse.

The key features of the UED's region are:

- it represents 24.6 per cent of Victoria's population and 25.4 per cent of the Victorian dwelling stock;
- it has very small shares of the agriculture and mining sectors;
- manufacturing activity accounts for 26 per cent of total Victoria;
- other machinery and equipment manufacturing in UED's region is over 37 per cent of the state total;

- other important manufacturing sectors in UED's region are paper and paper products, fabricated metal products and miscellaneous manufacturing; and
- the wholesale and retail trade sectors are important to UED's region, which services the major suburban shopping centres.

Key economic assumptions for UED's region are:

- population is expected to increase slowly over the forthcoming regulatory period. An increase of around 100,000 persons is projected between 2009 and 2019 under the base scenario, giving an average annual growth rate of 0.7 per cent compared to 1.4 per cent average for Victoria.
- Gross Regional Product is expected to rise by an average rate of 1.6 per cent between 2009 and 2019, slightly slower than the forecast Victorian average growth rate of 1.8 per cent over this period.
- total dwelling stock within the UED region is forecast to grow by an average rate of 0.7 per cent under the baseline scenario between 2009 and 2019, compared with a growth rate across total Victoria of 1.6 per cent per annum over the same period.

13.3.3 Climate change and other government policies

Energy businesses and the community are responding to climate change and the need for energy efficiency. The State and Federal Governments have adopted a number of initiatives to reduce emissions through lower energy consumption. The effectiveness of these Government-led initiatives will be enhanced by new technologies that provide greater scope for customers to reduce their energy needs.

Examples of initiatives that have been factored into UED's energy and load forecasts include:

- 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

Each of these matters is discussed in turn below.

13.3.4 The carbon pollution reduction scheme

The Australian Government proposes to introduce a CPRS, involving both a cap on the level of carbon pollution and the trading of permits, thereby placing a price on carbon pollution. The Government initially set a timetable to establish the CPRS by the commencement of 2010. However, on 5 May 2009 the Prime Minister announced his intention to delay the introduction of the scheme until 1 July 2011.

McLennan Magasanik Associates (MMA) has conducted detailed modelling of the economic effects of introducing the CPRS. MMA's analysis indicates that the CPRS will lead to a reduction in the volume of electricity sales in excess of 4 per cent by 2010. A lower rate of growth from this lower base is expected for the duration of the forthcoming regulatory period.

ACIL Tasman for the Energy Supply Association of Australia (ESAA), has also modelled the effect of the CPRS, and concludes that the CPRS will lead to:

- a reduction in energy consumption; and
- an increase in micro generation in response to increases in energy prices.

13.3.5 Minimum energy performance standards (MEPS)

MEPS and energy rating labelling have been applied in Australia to a range of appliances and equipment since the late 1980s, the range being continuously expanded and the MEPS upgraded. The MEPS have been developed in cognisance with world best practice which has strongly influenced the energy performance of appliances in Australia as many appliances are imported.

MEPS are based on the costs and benefits of enhancing energy performance for particular appliances. Introduction and upgrading is subject to rigorous analysis through Regulatory Impact Statements (RIS). The labelling of MEPS compliant appliances which are mainly purchased by households is controlled by a labelling standard and provides information on the appliance's star rating (up to 6 stars with the intention to go to 10 stars) and the energy use per year under standard test conditions.

In the Victorian residential sector by 2013 virtually all electricity use will influenced by:

- MEPS/energy labelling;
- increased electricity prices under the CPRS; and
- enhanced household environmental concerns.

In November 2009 a MEPS for lighting will be introduced. This will remove most incandescent light globes (general service lamps) and some Low Voltage Halogen (down-lights, reflector bulbs) from sale. The MEPS will initially be set at a minimum of 15 lumens per watt (incandescent are about 7 lumens per watt).

UED estimates that MEPS for air conditioners will reduce energy sales by about 15 GWh by 2019 as 285,000 new and replacement air conditioning units are forecast to be sold between 2010 and 2019. UED also estimates that summer and winter peak demand will reduce over the same period by about 20 MW and 7.5 MW respectively.

13.3.6 Standby power

Standby power accounts for about 11 per cent of electricity use in Australian households (Current Status Report, 2006). A one watt target in standby power is planned for all electrical appliances and equipment by 2012.

This will reduce demand, as the average standby power of appliances currently, is approximately four watts (this varies by appliance with lap top/notebook computers having a standby of approximately 9.2 watts). To forecast savings, NIEIR took into account an average of 15 appliances on standby per household. The cumulative reduction in total energy sales in Victoria is 194 GWh (by 2018-19), of which 49 GWh is attributed to UED's region. The cumulative reduction in UED's summer and winter peak demands is 10.3 MW and 11.8 MW respectively by 2018-19.

13.3.7 Federal insulation program

The program provides for up to $1,200 for installation of insulation in uninsulated ceilings (insulation value of R0 to R0.5 quality) over 2009-2012. NIEIR has estimated savings across UED's region 33.7 GWh by 2012-13.

13.3.8 Photovoltaic

Small scale photovoltaic electricity generators are being supported by Federal and State initiatives, and together with decreasing PV system costs there has been a significant increase in their installation. In Victoria from 2010, a net feed-in-tariff of $600 per MWh will be offered.

From 2009-10 to 2018-19, UED's share of the total Victorian impact, in cumulative terms, is forecast to be 10.3 GWh for an estimated 10,700 PV installations. A 7.3 MW impact is also forecast for the summer peak.

13.3.9 Victorian energy efficient target

The Victorian Energy Efficiency Target (VEET) initiative commenced on 1 January 2009. The target for Phase 1, which will continue through to 2011, is 2.7 Mt CO_2e of deemed greenhouse gas abatement (GHGA) per year.

Six categories of activities are specified as prescribed activities in the VEET Regulations:

- Water heating: Decommissioning of low efficiency water heating products and the installation of high efficiency water heating products. This category also includes the installation of solar pre-heaters or solar retrofit kits.
- Space heating: Decommissioning of low efficiency ducted heating products and the installation of high efficiency ducted heating products, and the installation of high efficiency space heating products.
- Space conditioning: Installation of insulation, thermally efficient windows and weather sealing products.
- Lighting: Installation of low energy lamps.
- Shower rose: Decommissioning of non-low flow shower rose and the installation of low flow shower rose.
- Refrigerators/freezers: Purchase or high efficiency refrigerator or freezer (refrigerator purchase) and destruction of pre-1996 refrigerator or freezer (refrigerator destruction).

Many of the VEET measures, or approved activities, overlap with other Federal and State policies. These include initiatives relating to hot water, and heating and insulation. In order to avoid double counting, and given uncertainties over the success of the scheme, only 10 per cent of the potential savings have been included in the electricity projections for Victoria. This implies a projected cumulative saving of only 31.8 GWh in UED's region, assuming the VEET scheme is extended to at least 2014-15. VEET is also forecast to have a small impact on the winter peak of 3.6 MW in total by 2014-15 when the programs impacts are expected to cease cumulating.

13.3.10 Residential building standards

The current five star standard in Victoria covers the building shell/envelope and requirement for either a solar hot water system or a water tank fitted into the residence's water system.

Through a COAG process the Federal, State and Territorial Governments have agreed to move towards a six star residential standard by 2012 for residence envelopes/shells. The six star standard might also incorporate a lighting standard (lumens/m2) and there may be differential policies by jurisdictions with respect to water heating (low emissions) and fixed equipment (space heating and cooling).

Victorian analysis (Isaacs, GWA) indicates that a move to a six star shell/envelope from five star would reduce, for a standard residence, space heating and cooling requirements by 15-20 per cent if actual performance matched design performance. A six star standard would probably not apply to new residences until post-2012.

Based on the assumption provided by NIEIR, the cumulative impact on UED's region energy for 2008-09 to 2018-19 is 4.8 GWh. For the winter peak, cumulative impact is forecast as 1.4 MW, summer impact 2.7 MW.

13.3.11 AIMRO Roll Out

In early 2006, the Victorian Government formally endorsed the deployment of AMI to all Victorian electricity consumers consuming less than 160 MWh per annum. Subsequently, the Government's Cost Recovery Order in Council ("CROIC") established a legal mandate for distributors to roll-out AMI meters. In addition to the CROIC the Functionality and Service Levels Specifications Order in Council further defines a range of requirements for the deployment of AMI, including minimum AMI functionality, performance and service levels and phasing timelines for these meters.

UED remains dedicated to implementing the Victorian Government's AMI policy. This policy requires UED to replace the existing accumulation meter at each customer site with a new AMI meter. It is the biggest project ever undertaken by UED and involves:

- replacing meters at approximately 658,000 customer sites;
- deploying a new communications network;
- installing new supporting IT systems; and
- redesigning its business processes.

The timeline established in the CROIC requires UED to use best endeavours to observe the following percentages of the total number of AMI meters to be installed:

- by 30 June 2010 – 5 per cent;
- by 31 December 2010 – 10 per cent;
- by 30 June 2011 – 25 per cent;
- by 31 December 2012 – 60 per cent;

- by 20 June 2013 – 95 per cent; and
- by 31 December 2013 –100 per cent.

In addition to the regulatory framework established by the Victorian Government the AER has made a draft decision in relation to interval meter reassignment requirement. In this decision, published 13 March 2009 the AER states on page 18:

> " The AER considers it appropriate to allow for distributors to reassign customers to TOU network tariffs as part of the Victorian Government's interval meter rollout. However it will be at the distributors' discretion to actually reassign individual customers, or classes of customers, from existing distribution tariffs to the new TOU network tariffs."

In order for the full benefits of AMI to be realised UED intends to reassign customers to time of use tariffs at the time an AMI meter is installed. Therefore by the beginning of 2011, 15 per cent of meters will be installed and these customers will be reassigned to a time of use tariff.

The forecasting assumptions used for the remainder of the roll-out will be based on half the meters installed for each six month period being transferred to time of use tariff.

The next component of the migration is to forecast the load profile for customers. In order to determine the existing customer usage UED has approximately 3,000 interval meters already installed at customer premises. UED's preferred methodology was to utilise the data from these meters to determine a split between peak, off-peak and shoulder energy usage. UED believes that this data source is the most accurate for forecasting. It is based on empirical data from meters at existing sites. At this stage these customers are not on time of use tariffs therefore the usage information received from these meters is before any assumptions regarding price elasticity.

However, before simply using actual interval metering data UED has taken two other data points as a check on the actual meter reading data. The two other data points are:

- interval metering data installed at a (predominately) residential feeder; and
- net system load profile data provided by AEMO. Net system load profile represents how the rest of UED customers not on interval meters behave on a half hourly basis. This data is used to determine peak, off peak and shoulder splits based on any time of day period.

The results of these three different data points are provided in the Table 13-2 below:

Table 13-2: Comparison of usage patterns

Description	Peak	Shoulder	Off Peak
S1 interval sample	28%	21%	51%
Residential feeder	29%	22%	49%
Net system load profile	28%	25%	47%

The results obtained from the three independent data sources are very similar. This analysis confirms the validity of UED's original assumption regarding actual interval meter reading data. Accordingly the S1 interval sample percentage has been used as a basis for forecasting tariff consumption data prior to any price elasticity effect.

This is the most reasonable estimate given the data sampling is based on a summation of actual data points rather than more aggregated information.

13.3.12 AIMRO elasticity

AMI meters will provide customers with data and tools not previously available to them. Notably AMI meters will provide consumers with half hourly meter reading data and pricing data. Customers will use this data to inform their future consumption patterns.

In addition to this information UED has in place time of use and time of day tariffs that will reward (via cheaper tariffs) lower usage in peak periods, by switching the use of appliance to periods outside the peak. NIEIR have taken account of these factors in its load and maximum demand forecasting.

13.4 Maximum demand, energy and customer number forecasts

Forecast maximum demand growth in the residential sector is underpinned by the increasing penetration of air conditioning units. Air conditioning units add significantly to the summer peak demand, but contribute substantially less to annual energy consumption growth.

United Energy's overall summer peak demand is expected to occur on a weekday (excluding last week of December and the first three weeks of January) between 1 December and 31 March.

In Summer 2008/09 UED recorded a summer peak demand of 2,070 MW at 1:00pm AEST on 29 January 2009 when the ambient temperature reached 44ºC (ambient temperature on the day corresponded to 2 percentile probability of exceedance). On the same day and around the same time, there was a widespread load shed in UED network due to outages in the Victorian transmission network. It is estimated that the UED network would have recorded a peak of around 2,110 MW at 3:00pm AEST if there had been no transmission outages. This is a conservative estimate of the peak demand that could have occurred as other factors were acting to reduce demand on the day including low voltage and high voltage distribution outages (e.g. fuses operating under overload) and industry and school closures due to the hot weather.

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. Historically, NIEIR, have been producing 27 sets of summer maximum demand forecasts based on the following scenarios:

- Three economic growth scenarios - Medium, High and Low;
- Three summer season weather probabilities (10th, 50th and 90th percentile) for each of the above economic scenarios;
- Three summer day weather probabilities (10th, 50th and 90th percentile) for each of the above scenarios.

The summer weather probabilities are calculated on the basis of average daily temperature (being the arithmetic average of the overnight minimum and the daily maximum) and average season temperature, over December to March period, using 50 years of historical data. Table below presents the results:

Table 13-3: Summer weather probabilities

Probability of Exceedance	Average Day Temperature	Average Season Temperature
10th Percentile	32.9º C	21.3º C
50th Percentile	29.4º C	20.4º C
90th Percentile	27.3º C	18.8º C

Based on the above, if the average daily temperature on a day reaches 32.9º C, the event is considered to be a 1 in 10 year event (generally referred to as 10th percentile probability of exceedance or 10 per cent PoE).

In developing maximum demand forecasts, it has been assumed that there is a direct correlation between demand and ambient temperature, i.e, the 10, 50 and 90 per cent PoE peak demand projections were directly related to the 10, 50 and 90 per cent PoE of temperatures. . Hence, if the average daily temperature on a day reaches 32.9º C, it has been assumed that the peak demand on the day would also reach 10 per cent PoE. UED has adopted the "50th percentile average summer season weather probability" and "10th percentile average summer daily probability" as the basis for capacity planning and simply referred to it as 10 per cent PoE forecasts.

Maximum demand forecasts have been based on the above methodology up to 2008. This approach, however, has been challenged over recent years for a number of reasons (such as the effect of the day of the week, consecutive hot days, etc, on maximum demand) and the methodology for defining PoEs for maximum demand has been changed. Starting from 2009, it has been decided to adopt an improvement to the existing approach for projecting maximum demands. This approach is called PeakSim and it is a more sophisticated planning methodology that builds on similar basic assumptions as UED's original planning approach.

The PeakSim model generates probability distributions of peak demand from synthetically generated distributions of temperature and demand. This contrast with the more deterministic earlier approach that relates peak demand forecasts to given temperature levels. It outputs thousands of synthetic demands for each half-hour period over each season. Probability of exceedance levels are then drawn directly from this simulated data (rather than from temperature only).

PeakSim model incorporates the impacts of Federal and State Government's energy and environmental policies on demand, energy prices from policy measures such as the proposed Emissions Trading Scheme and the expanded Mandatory Renewable Energy Target, and other policy measures such as changes to Minimum Energy Performance Standards (MEPS) – e.g. effect on lighting and air conditioners, as well as taking into account the roll out of smart meters and electric cars and the phase out of electric resistance hot water heaters.

Unlike energy, most growth in maximum demand is forecast in the residential sector underpinned by higher penetration of air conditioning units. Projections of United Energy Distribution overall summer maximum demand for medium economic growth scenario with

10 per cent and 50 per cent probability exceedance are presented in the chart below. The chart also presents the impact of energy policies of federal and state governments on the summer maximum demand.

The medium growth scenario with 10 per cent PoE (1 in 10 years) summer day has been adopted for planning purposes for the following reasons:

- Load growth forecasts carry a degree of uncertainty in predicting both the economic conditions and the summer weather. The degree of uncertainty increases as one moves from the bulk supply point into zone substations, then HV feeders, then distribution substations and finally LV-feeder levels. This uncertainty in the context of high network utilisation supports the adoption of a 10 per cent PoE weather scenario for planning purposes rather than a 50 per cent PoE.

- To avoid the situations which have occurred in Western Australia, NSW and Queensland in 2002/03/04 where demand outgrew supply-side capacity, it is prudent for demand reinforcement expenditure to be based on a medium economic growth scenario, a normal (50 per cent PoE) summer and a 10 per cent POE summer day..

- UED has amongst the highest network utilisation rates in Australia and the peak demand for network services is becoming increasingly temperature-sensitive. It is estimated that load in UED's region that is temperature sensitive has risen from around 400 MW in 1989/90 to nearly 700 MW in 1999/00 and over 1,160 MW in 2007/08 (being more than 50 per cent of UED peak demand).

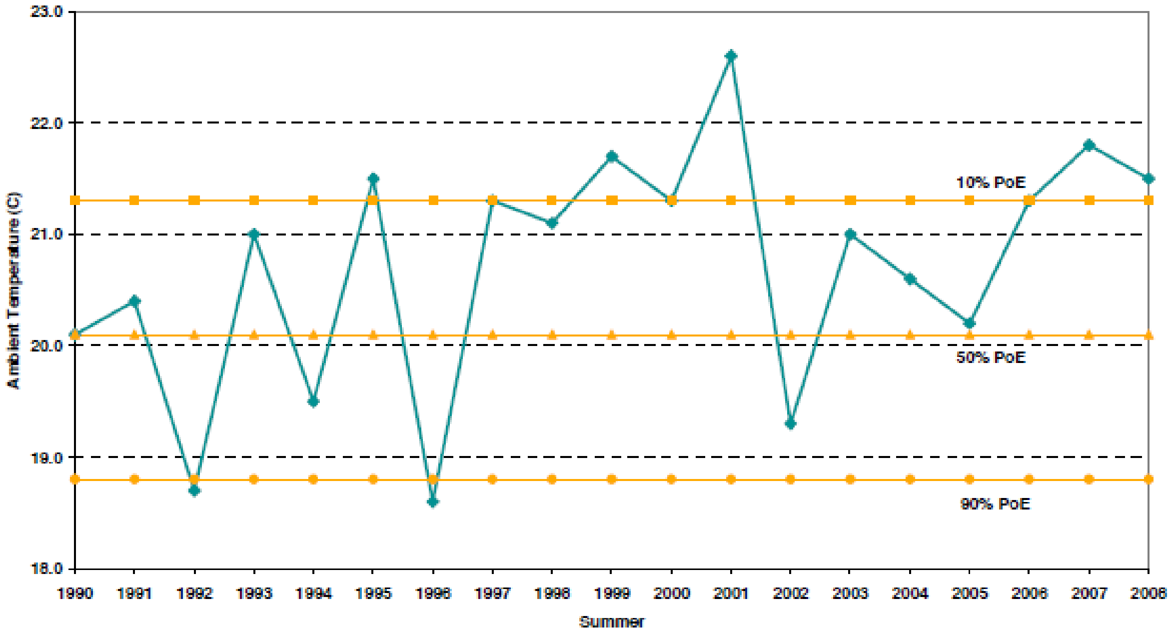
- Analysis of Melbourne weather data shows that average summer monthly temperatures since 1997 have reached or exceeded the long term (50 years) 10th PoE average summer monthly temperature in eight of the past 19 years, as shown below.

- 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 expected to be very critical in economic justifications.

- 10 per cent PoE forecasts are mainly used as a trigger for further investigation (rather than the main and the only driver for augmentation) for UED.

- UED's overall peak demand exceeded its 10 per cent PoE forecast by 67 MW in summer 2008/09. Given that energy at risk and expected unserved energy rather than peak demand are used in economic justifications and maximum demand forecasts are mainly used as a trigger for further investigation, adoption of 10 per cent PoE is considered the most appropriate for UED as it will provides ample time to prepare and implement suitable plans.

Figure 13-2: Average summer monthly ambient temperatures, 1990 - 2008



In December 2008, NIEIR was engaged to review UED's summer forecasts in the light of the downturn in the economy. The following chart compares the overall UED forecasts in December 2008 (which take into account the impact of an economic downturn) with June 2008 (which excludes the impact of economic downturn) and October 2009 forecasts (based on PeakSim and includes the impact of energy policies) under medium economic growth scenario with 10 percent probability of exceedance.

The timing of network augmentations in this plan is based on the October 2009 load forecasts with due regard to energy policies and the highest rating currently assigned to the respective plant items. Any variation in the actual load growth from the projected figures is assessed annually and is accommodated by varying the timing of implementation of the proposed works.

Figure 13-3: Maximum summer demand forecasts, 2009 versus 2008

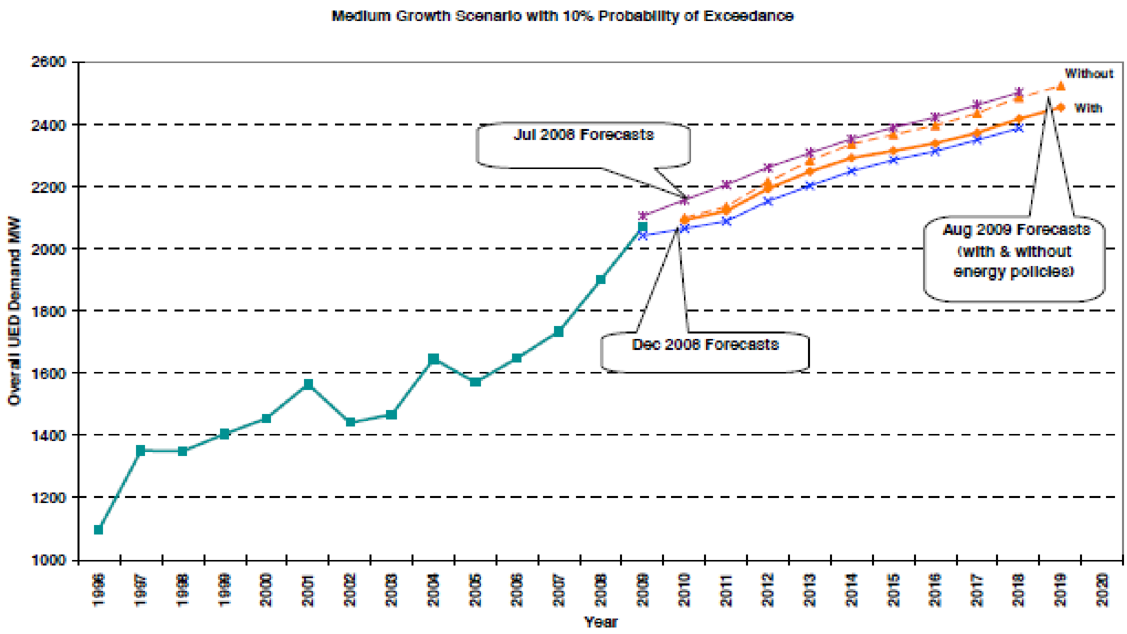
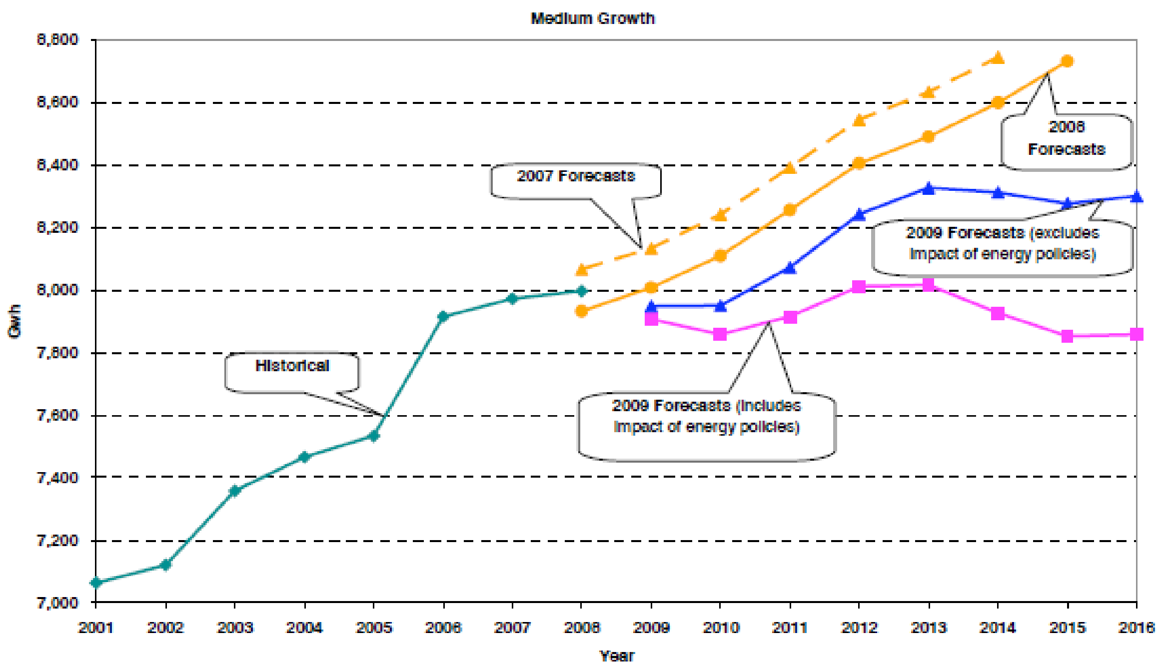


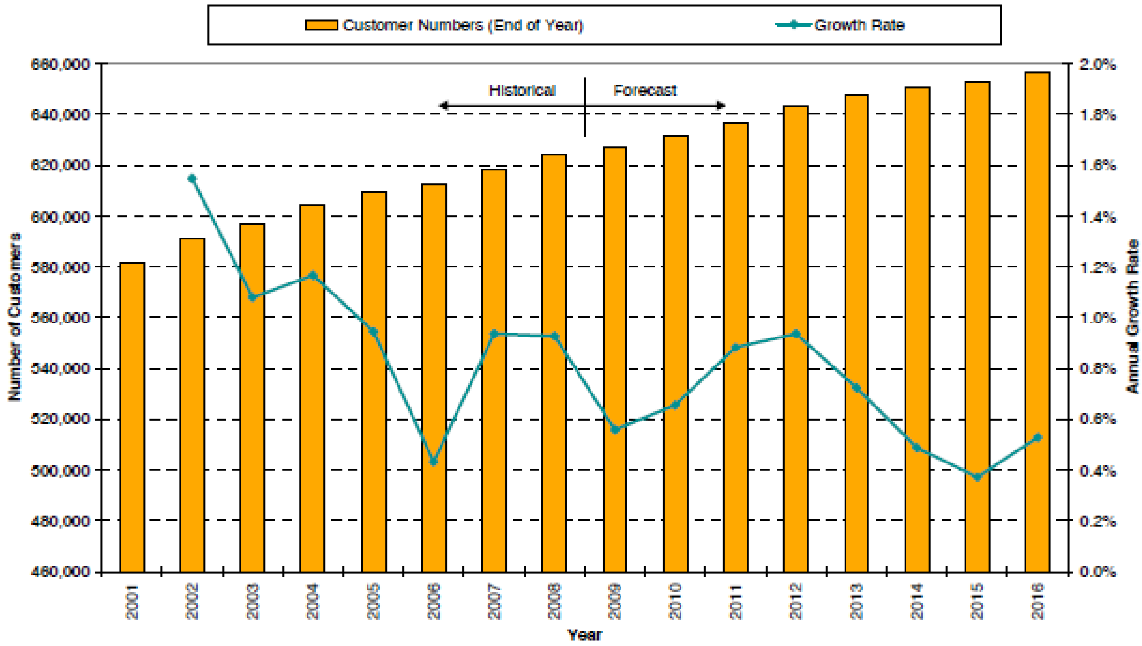
Figure 13-4: Annual forecast of energy sales to 2016



The figures above show that national and state energy and climate change policies will have a significant impact on UED's future energy sales. If energy 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 2008-2016 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 is mainly due to the uptake of air conditioning units and will be less affected by climate change policies.

Customer numbers are forecast to grow at a rate of 0.64 per cent per annum over the 2008-2016 period under medium economic growth scenario. Table 13-5 below shows historic and forecast growth in customer numbers from 2001 to 2016.

Figure 13-5: Customer Growth 2001 - 2016



13.5 Summary of forecasts for the forthcoming regulatory period

This Chapter has described UED's forecasting methodology and identified a range of factors that will put significant downward pressure on future energy and load requirements. The Chapter also noted that UED and NIEIR have a good forecasting record, and therefore the analysis presented here should be highly regarded.

UED's customer number forecast is contained in Table 13-4 below:

Table 13-4: UED's forecast customer numbers 2011 - 2015

Category	Year Ending 31 December				
	2011	2012	2013	2014	2015
Opening Customers	625,181	630,193	634,296	637,563	641,373
Plus new connections	11,252	10,447	9,719	10,374	11,756
Less abolishment's	- 6,240	- 6,348	- 6,456	- 6,564	- 6,672
Total Customer numbers	630,193	634,296	637,563	641,373	646,457
Average customer numbers	627,687	632,244	635,930	639,468	643,915

UED's energy and maximum demand forecasts are shown in Table 13-5 below.

Table 13-5: UED's energy and maximum demand forecasts 2011 - 2015

	Year Ending 31 December				
Category	**2011**	**2012**	**2013**	**2014**	**2015**
Energy (GWh)	7,793	7,734	7,592	7,478	7,486
Maximum demand - 10th percentile (MW)	2181	2253	2296	2390	2434
Maximum demand - 50th percentile (MW)	1992	2061	2102	2142	2180

The tables above indicate 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.

14. Tariffs

Key messages

- 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 and the opportunity it presents in terms of changing customer behaviour.
- UED will also examine initiatives for increasing the participation of the demand side of the market.
- UED's indicative prices for direct control services reflect the building block calculations presented in this Regulatory Proposal.

14.1 Regulatory requirements and chapter structure

Clause 6.8.2(c)(4) of the Rules requires that a Regulatory Proposal must provide indicative prices for direct control services for each year of the regulatory control period. This requirement is addressed in section 14.3 of this Chapter. Before turning to the indicative prices for the forthcoming regulatory period, section 14.2 provides a high level commentary of UED's tariff strategy and some of the possible developments over the course of the forthcoming regulatory period.

14.2 Tariff Strategy

UED will continue to review the effectiveness of its existing tariffs. It is expected that there will be some refinements to existing tariffs, during the 2011 - 2015 regulatory period.

The introduction of new tariffs will be aimed at maintaining UED's operating revenue while encouraging customers to change their consumption so that there is an overall improvement in asset utilisation and system load factor.

To assist in addressing issues such as AIMRO reassignment, UED will work with stakeholders and any other group set up to consult on the interval meter reassignment requirements.

Participation in these groups will attempt to address issues around the current pricing arrangements (e.g. adoption of ToU tariffs), and to engage stakeholders in identifying 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.

The following issues will also be subject to ongoing evaluation, consultation, and if appropriate, implementation over the 2011 - 2015 regulatory period:

- packaging of load control services and other value added services with tariffs to enhance performance of tariffs for both customers and UED;

- use of incentive pricing within the existing tariff structure to ensure that customers are exposed to appropriate price signals;
- the Summer Demand Incentive Charge (SDIC) concept will remain, but the time window may be updated from time to time in order that it remain aligned with the key network peak demands;
- cost-of-supply modelling will be updated to reflect changes in relative contributions from segments and the ability of new meters to record the response and assist response to price signalling;
- tariff changes may further emphasise the costs of meeting peak season (summer) demand on particular days of the week and time of day in order to stimulate demand side management response;
- review charging arrangements for distribution-connected generator customers to ensure charges are cost reflective;
- further closure of tariffs based on obsolete metering;
- consider the introduction of premium service tariffs whereby customers obtain enhanced supply reliability and services;
- an increased number of time-of-day bands, with greater peak / off-peak differential, and energy and distribution tariff components peaking at different times; and
- demand management (DM) programs aimed at different customer classes will be investigated, for example:
    - interruptible tariffs for business customers whereby customers agree to reduce their power consumption for agreed periods at the request of the distributor (likely to be at a time like a hot summer afternoon when the system is heavily stressed), and in return issue some form of compensation payments;
    - DM aggregation program, which involves working with a range of customers and bidding their combined interruptible load in either the wholesale energy or ancillary services market;
    - investigate the specific area of co-operation with retailers, DM aggregators, and large customers in developing robust DM programs that deliver benefits to all parties; and
    - investigate positive pricing incentives such as rewards and rebates as motivational mechanisms for DM.

14.3 Indicative prices for standard control services

Table 14-1 below provides the indicative prices for 2011 (in real 2010 prices).

Table 14-1: Indicative prices for standard control services for 2011

Forecast Prices	Fixed	Peak Summer	Shoulder Summer	Shoulder Non-Summer	Peak Non Summer	Off peak	Rolling Demand	Summer Demand
Low voltage small 1	5.77	7.05	-	-	4.54	-	-	-

Forecast Prices	Fixed	Peak Summer	Shoulder Summer	Shoulder Non-Summer	Peak Non Summer	Off peak	Rolling Demand	Summer Demand
rate								
Winter economy tariff	7.68	5.72	-	1.59	4.24	-	-	-
Reverse Cycle air conditioning time of use	-	4.97	-	-	1.25	1.23	-	62.51
Low voltage small 2 rate	12.17	8.74	-	-	6.63	1.52	-	-
Dedicated circuit	-	-	-	-	-	1.43	-	-
Low voltage medium 1 rate	11.24	9.88	-	-	6.16	-	-	-
Low voltage medium 2 rate 5 day	16.14	7.84	-	-	5.96	1.49	-	-
Low voltage medium 2 rate 7 day	17.33	7.53	-	-	5.92	1.40	-	-
Unmetered supplies	-	7.25	-	-	5.30	1.31	-	-
Low voltage large 2 rate	15.64	7.77	-	-	6.18	-	-	-
Low voltage large 1 rate	10.84	4.96	-	-	3.92	1.48	-	-
Low voltage large KW time of use	-	7.00	-	-	4.10	1.63	-	33.51
Low voltage large KW time of use – HOT	-	6.27	-	-	4.82	1.42	-	55.15
Low voltage large KVA time of use	-	1.10	-	-	0.93	0.92	11.06	16.50
Low voltage large KVA time of use – HOT	-	0.98	-	-	0.81	0.80	11.23	26.48
High voltage KVA time of use	-	0.66	-	-	0.58	0.57	6.73	9.24
High voltage KVA time of use – HOT	-	0.69	-	-	0.58	0.57	7.91	19.17
Subtransmission KVA time of use	-	0.38	-	-	0.30	0.26	0.67	0.98
TOD	5.90	15.91	4.48	3.30	9.38	3.07	-	-
New KWTOU	-	7.61	-	-	4.66	2.30	-	32.73

Amounts shown in real 2010 terms.

The proposed prices for the remaining years of the forthcoming regulatory period are contained in the RIN.

15. CONTROL MECHANISMS

Key messages

- UED as adopted the control mechanisms as set out in the AER's Framework and Approach Paper.
- UED notes that the S-factor calculation will be based on estimated performance in 2010, and therefore a reconciliation will be required to reflect actual service performance.
- For administrative simplicity, UED proposes that CPI should be applied annually to the approved prices for alternative control services.
- 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 notes that there is a need for clauses 6.18.2 and 6.18.7 of the Rules to be corrected to clarify that a DNSP is able to fully recover all transmission connection and transmission use of system charges. This matter was raised with the AEMC during the recent review of national arrangements for distribution planning, and the AEMC has undertaken to consider how this issue may be best addressed.
- UED supports the retention of the existing tariff re-balancing constraints.

15.1 Regulatory requirements and chapter structure

Clause 6.12.3(c) of the Rules requires the AER to set out in its Framework and Approach Paper the control mechanisms to apply for the forthcoming regulatory period. In deciding on a control mechanism for standard control services the AER must have regard to the following factors set out in clause 6.2.5(c) of the Rules:

- the need for efficient tariff structures;
- the possible effects of the control mechanism on administrative costs of the AER, the DNSPs and users or potential users;
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination;
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

In light of the Rules requirements and the AER's Framework and Approach Paper the remainder of this chapter is structured as follows:

- Section 15.2 provides the control mechanism to be applied to standard control services;

- Section 15.3 describes the weighted average price cap to be applied to standard control services;
- Section 15.4 discusses matters relating to the control arrangements to permit full recovery of transmission charges by UED;
- Section 15.5 describes the control mechanisms to be applied to alternative control services;
- Section 15.6 discusses re-balancing constraints;
- Section 15.7 describes UED's approach to the Premium feed in tariff requirement; and
- Section 15.8 describes the control mechanisms for public lighting.

15.2 Control mechanism for standard control services (DUoS)

The current control mechanism for prescribed distribution services is a weighted average price cap. In its Framework and Approach Paper the AER has determined that the weighted average price cap will remain in place for the forthcoming regulatory period.

Although the AER has proposed to retain the weighted average price cap it has proposed some changes to its formulation. Specifically, the AER has replaced the current S-factor scheme with the AER's STPIS. The current S-factor adjustments will be addressed through the building block components.

UED welcomes the approach adopted by the AER to retain the weighted average form of price cap. UED notes that the current S-factor scheme calculation, to be included in the building blocks, will be based on estimated data for 2010. On this basis, the price cap formulation should also include an adjustment in 2012 for the final "wash up" between the actual S-factor scheme and the amount allowed in the revenue building blocks.

15.3 Application of a weighted average price cap

In its Framework and Approach Paper, AER concluded that a weighted average price cap should apply to standard control services in the next regulatory control period, noting that:

- a weighted average price cap is the current control mechanism for the Victorian DNSPs' prescribed distribution services and is one of the control mechanisms listed in clause 6.2.5(b) of the NER that can be applied in the next regulatory control period;
- transitioning to a completely new form of control mechanism would not guarantee a reduction in administrative costs, and may itself create undesirable administrative costs;
- the incentives and risks of this control mechanism are widely recognised. Importantly, this form of control allows the Victorian DNSPs to manage uncertainty in outturn volume by re-balancing their tariffs.

In terms of the detailed operation of the control, the AER concluded that:

- AER will retain the "L" factor (which recovers licence fees) in the control mechanism, for as long as it is being charged;
- The existing S-factor scheme will be replaced with the AER's STPIS; and

- The AER will carryover any adjustments arising from the EDPR, for example, in relation to "L" and "S" factor adjustments, that will impact in the 2011–15 regulatory period.

The form of the AER's weighted average cap is as follows:

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

UED supports the AER's proposed weighted average cap for standard control services, subject to one modification. UED proposes that an additional factor, Ft, is included in the formula to allow UED to recover the costs of the new feed-in tariff, which rewards customers for exporting their surplus power onto the distribution network. The inclusion of this additional term preserves the AER's preferred form of the control, whilst providing an appropriate cost recovery mechanism for UED.

In relation to the S-factor UED proposes the following principles to apply for the current S-factor mechanism and transition to the STPIS scheme:

- 2011 tariffs include the current S'_t component for 2009 performance and the t-6 component (consistent with the current tariff formula);
- the 2012 tariff no longer includes the current S'_t component however it includes an adjustment factor to close out the current scheme which is calculated from actual performance for 2010 and all the t-6 components not already completed (in effect this finalizes the current scheme including actual performance for 2010);
- by 2013 the tariff includes an S_t component for 2011 performance under the new STPIS scheme.

Appendix H-1 provides further details of the method.

15.4 Full recovery of transmission charges

Clause 3.3.2 of the ESC's 2006 EDPR Determination contains a network tariff control that explicitly enables UED to recover the aggregate of all transmission connection and transmission use of system charges levied by the holder of a transmission licence.

Clause 6.18.7 of the Rules sets out provisions relating to the recovery of charges for transmission use of system services. This clause appears to seek to give effect to a similar sort of transmission cost recovery arrangement as that contained in clause 3.3.2 of the 2006 EDPR Determination. That is, the intention of clause 6.18.7 appears to be that a distributor should recover no more or no less than the total transmission charges actually levied on it by TNSP(s). However, Clause 6.18.7 of the Rules refers only to "transmission use of system services" and "transmission use of system charges".

It is noted that "transmission use of system" is defined in the Rules so as to exclude connection services. Technically then, Clause 6.18.7 does not appear to provide for the recovery by distributors of transmission connection charges levied on them by TNSPs. This appears to be an oversight in the drafting of the Rules provisions, as it would be illogical for the Rules to sanction the full recovery by distributors of transmission use of system charges, but to make no allowance or provision to permit the distributors to also recover transmission connection charges.

Given the considerations set out above, the Victorian DNSPs' recent submission to the AEMC review of the national framework for electricity distribution network planning and expansion[92] noted that:

> " The Victorian DBs [consider] that while clause 6.18.7 of NER appears intended to allow for full pass-through of transmission use of system and transmission connection charges by DNSPs, that clause (inadvertently) does not explicitly provide for the recovery by DNSPs of transmission connection charges.
>
> The AEMC's present review provides an opportunity to correct this discrepancy. We therefore propose that clause 6.18.7 should be amended to provide for the full pass-through by a DB of all charges levied on it in relation to transmission services. We would welcome the Commission's confirmation of its intention to address this matter in the course of the present review; alternatively, it may be considered to be more appropriate to address this matter through the "fast track" Rule change process."

In response to these submissions, page 24 of the AEMC's Final Report on the review of the national framework for electricity distribution network planning and expansion stated that:

> " There may be broader issues relating to cost recovery such as the queries raised about the provisions for the recovery of charges for transmission use of system services under the Rules. In their joint submission on the Draft Report, Victorian distribution businesses (p. 9) proposed that clause 6.18.7 of the Rules, recovery of charges for transmission use of system services, should be amended to provide for the full pass-through of all charges levied on a distribution business in relation to transmission services. We will consider how these issues may be best addressed."

At the time of preparation of this Regulatory Proposal, this issue had not been resolved.

UED envisages that by the commencement of the forthcoming regulatory period (1 January 2011) the drafting of clause 6.18.7 will be amended to provide for the full recovery by distributors of transmission connection charges and transmission uses of system charges levied on them by TNSPs. In this context, it is also noted that similar drafting amendments will need to be made to clause 6.18.2 of the Rules, which requires a DNSP in its Pricing Proposal to:

> " set out how charges incurred by the Distribution Network Service Provider for transmission use of system services are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those charges in the previous regulatory year."

Once the drafting of clauses 6.18.2 and 6.18.7 is corrected, the process of the AER's annual consideration of a DNSP's Pricing Proposal can be used to verify that the relevant DNSP is fully recovering all transmission connection and transmission use of system charges, and that any over or under-recovery of those charges from previous years is properly taken into account in the calculation of the DNSP's proposed prices.

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[92] **A copy of the submission is available from the AEMC's web page at the following address: http://www.aemc.gov.au/Media/docs/United%20Energy%20Distribution-41484fe7-af5b-4c89-8471-f9aebf4a01f2-0.pdf**

15.5 Control mechanisms for alternative control services

In its Framework and Approach Paper, the AER has determined that it will apply price caps in the next regulatory period to:

- unit costs for the quoted services groupings of alternative control services; and
- individual prices for all of the other alternative control services, with a limited building block approach being applied to the operation, repair, replacement and maintenance of public lighting assets.

UED concurs with this approach and notes the following points:

- The current pricing for excluded services has not been adjusted since 1999. Attached to this submission as an appendix is a full re-pricing of these services. The re-pricing is based on the information received from the market based tendering 7/11 project undertaken by UED and the application of UED's Cost Allocation Methodology.
- UED proposes that the CPI for the period should be applied annually to the approved prices for alternative control services. This is consistent with a price cap approach and is administratively simple. This proposed approach ensures that prices continue to be cost reflective. The resulting prices can be included in the annual tariff approval process.
- If there is a pass through event which affects the costs of providing alternative control services, the approved prices for the affected services should be adjusted to reflect the outcome of the pass-through determination.

Clause 6.2.6(c) provides that the control mechanism for alternative control services may utilise elements of Part C and an example included is that the distribution determination may provide for the application of clause 6.6.1 to pass through events with necessary adaptions and specified modifications. UED's proposal is that if a pass through event occurs and is dealt with under clause 6.6.1 in relation to standard control services and there is also a consequential on alternative control services, then the provisions of 6.6.1 would apply to that impact as well. A separate pass through regime for alternative control services is not proposed. Clause 6.6.1 would apply as if the reference to 'standard control services' in item (j)(2) were a reference to alternative control services.

All RIN compliance requirements relating to alternative control services have been addressed in appendix C-2 including the proposed re-pricing of all services.

15.6 Re-balancing constraints

Under the current regulatory arrangements, the average annual increase in each distribution and transmission tariff to CPI+2 per cent. However, as transmission charges are regulated as a cost pass through, distributors can apply for an easing of the transmission constraint to allow for the pass through of large increases in transmission charges. UED proposes that the same rebalancing constraint is retained for the forthcoming regulatory period.

15.7 UED's approach to the premium feed in tariff

On 6 November 2009 UED submitted a pass through application for the recovery of costs associated with the legislative requirement to comply with premium feed in tariffs ("PFIT").

This application proposed a new fixed charge tariff to apply to all customers. This tariff is designed to recover two specific costs – these being:

- The 60 cents per KWh paid by UED to all eligible customers; and
- The administration costs in establishing and managing this new legislative requirement.

This Regulatory Proposal is that the fixed charge approach proposed by the pass through application remains in place for the forthcoming regulatory period. UED notes however that the tariff should be amended in 2011 to only recover the cost to UED of the 60 cents per KWh component. The administrative cost of managing and complying with the scheme has been included in the base forecast under "billing & revenue".

This Regulatory Proposal does not contain forecasts for

- the amount paid by UED (60 cents per KWh) to be operating expenditure under clause 6.5.6; or
- revenue received from customers in order to compensate UED for these payments.

Given that the proposed approach to PFIT is based on a true up process in the annual tariff submission UED has chosen not to forecast either of these components given that they net to zero over the life of the PFIT program (and are designed to net to zero on an annual basis). Accordingly it would be inappropriate to deal with PFIT in the incentive regulatory framework. The 2011 tariff will be adjusted to reflect the outcomes of the AER's final decision on this Proposal.

15.8 Control mechanisms for public lighting

On 10 November 2009 the AER provided its final building block model in relation to public lighting. UED has chosen to adopt this model as a limited building block approach relevant for public lighting. This model applies a price cap control mechanism and is attached as part of this Proposal. The model is consistent with the current approach to public lighting pricing, and is attached as part of this Proposal.

16. Service Target Performance Incentive Scheme

Key messages

- 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 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.
- A cap of ±5 per cent of revenue on the sum of reliability of supply and customer service components is too high. The viability of the business would potentially be undermined, and customers would be exposed to wide and unpredictable tariff fluctuations.
- UED shows that S-factor percentage results are more volatile under the STPIS than under the current, ESC scheme. A cap of ±3 per cent applied to the sum of the raw S-factor components would help to dampen the significant oscillations in the S-factor.
- UED supports a major event day exclusion regime based on SAIDI. UED favours a statistical basis for determining exclusions, however does not believe that the major event day threshold should be updated annually.

16.1 Regulatory requirements and chapter structure

The AER has published a Service Target Performance Incentive Scheme ("STPIS") in accordance with clause 6.6.2 of the Rules to apply to electricity distributors in Victoria and elsewhere during the next regulatory control period. The STPIS seeks to provide a financial incentive for distributors to maintain and improve their service performance. The STPIS is a successor to the service target incentive scheme which was first implemented in Victoria by the then Office of the Regulator-General in 2001. Further details of existing S-factor arrangements in Victoria are provided in chapter 10 of this proposal.

The STPIS is a successor to the S-factor scheme which was first implemented in Victoria by the then Office of the Regulator-General in 2001. Further details of S-factor arrangements in Victoria are provided in Chapter 10 of this Regulatory Proposal.

Clause S6.1.3(4) of the Rules requires that a Regulatory Proposal must contain:

> " A description, including relevant explanatory material, of how the Distribution Network Service Provider proposes the service target performance incentive scheme should apply for the relevant regulatory period."

In complying with this Rules requirement, UED is required to take account of the following documents:

- Electricity Distribution Network Service Providers Service Target Performance Scheme Guidelines, November 2009 (STPIS Guidelines); and

- the AER's Framework and Approach paper in May 2009.

Clause 2.2 of the STPIS Guidelines allows a DNSP to propose to vary the application of the STPIS in its Regulatory Proposal, providing that the proposed service incentive scheme:

- includes the reasons for and an explanation of the proposed variation;
- demonstrates how the proposed variation is consistent with the objectives in clause 1.5 of the STIPS; and
- if appropriate, includes the calculations and/or methodology which differ to that provided for under this scheme.

Given these regulatory requirements, the remainder of this Chapter is structured as follows:

- Section 16.2 explains and presents UED's proposed service performance targets, which take account of expert advice on the effects of climate change;
- Section 16.3 addresses the issue of setting an appropriate cap on the maximum performance bonuses and penalties;
- Section 16.4 addresses the calculation of the incentive rates and weightings that should apply in the service incentive scheme for UED;
- Section 16.5 discusses whether public lighting and momentary interruptions ("MAIFI") should be included in the service incentive scheme for UED;
- Section 16.6 sets out UED's proposal in respect of exclusions from the service incentive scheme.

This chapter should be read in conjunction with the appendix H-4 attached to this proposal. This appendix provides further detail in relation to the STPIS.

16.2 Performance targets

16.2.1 Reliability of service and the implications for SAIDI

UED has developed a number of programmes aimed at maintaining the reliability of supply across its network as described in the asset management plan, including:

- A renewed focus on pole fire mitigation subsequent to the 2003 and 2007 summer pole fires.
- Greater emphasis on distribution load demand and asset management subsequent to the 2009 January heat wave.
- Vigilance in asset inspection and vegetation management.
- A focus on underlying causes with the objective of reducing the number of outages on rogue feeders and in poor performance areas.
- The adoption of Ground Fault Neutralisers (Petersen coils) in the network as a possible alternative to the installation of Neutral Earthing Resistors. The first project was completed in 2008-09.

- The development of a remote operating switching scheme - nicknamed ROSA - which turns sustained customer outages into momentary outages via the automated switching of the network after a fault.
- An assessment of bushfire risk as part of the consideration of pole fire and possum proofing programmes.
- The introduction of a Reliability Index to relate the contribution of outstanding asset replacement activities to the reliability incentive scheme.
- A testing programme for bushing components on 66kV transformers.
- A programme for monitoring and testing cable conditions.

Notwithstanding these programmes, UED believes that there is currently limited scope for further, major initiatives aimed at reducing SAIDI. The installation of underground cables in critical areas of the UED network would be a key component of a major, reliability and performance-based upgrade. However, the financial payoff or commercial return from such an upgrade is currently insufficient to justify the large outlays that would be required to deliver the improvement.

Incentive rates under the STPIS are expected to increase significantly from their settings under the current S-factor scheme, with values underpinned by a new, elevated estimate for VCR. However, UED's analysis suggests that even with a higher VCR, the potential rewards from further, substantive reliability projects are insufficient to justify the additional costs.

16.2.2 The impact of climate change

UED's network has, in the recent past, been exposed to more frequent weather events, including wind storms and temperature extremes. Another impact of emerging climate change has been an increase in pole fire incidents, most of which can be attributed to the extended drought conditions affecting Victoria. UED has responded by replacing wooden pole top structures.

UED commissioned independent consultants to investigate the impact of climate change and weather-related events on the company's distribution network over the period from 2011 to 2015. The research (AECOM 2009) 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 days from the CSIRO Mk3.5 model. The CSIRO (2009)[93] found that the annual average number of hot days and very hot days from 2011 to 2015 would be similar to the number reported for the 2008 reference year. The result emerged because 2008 was a particularly hot year, and because the modelling approach was somewhat conservative. AECOM therefore inferred that the forecast for SAIDI due to hot days in each year from

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[93] **CSIRO (2009). Climate Change in Southern South Australia and Western Victoria. Kevin Hennessey and Jim Rickets. A report prepared for Maunsell AECOM.**

2011 to 2015 would differ only marginally from the number reported for 2008. The incidence of low voltage (LV) and high voltage (HV) outages over the projection period would be similar to the results recorded for 2008. Accordingly, the impact on SAIDI was reported to be 0.9 minutes.

AECOM also examined the frequency of high wind days, using forecasts underpinned by the Mk3.5 model. The projections suggested that there would be a large increase, from 2011 to 2015, in the incidence of wind-related events, by comparison with the situation in 2008. AECOM estimated the effect on power supply outages by categorising wind events according to different wind thresholds and then measuring the relationship between the long-term average number of wind occurrences in each band and the long run average number of HV and LV faults. The number of future outage events was calculated by multiplying the ratio of outages to events in each band, by the forecast number of wind events, broken down according to wind speed category. The duration of events was computed using daily average SAIDI classified by wind speed range.

AECOM deduced that a higher average number of wind events per annum would give rise to a 28 minute increase in total SAIDI (AECOM 2009). The phrase ‘total SAIDI’ in this context refers to the sum of unplanned SAIDI, over the course of a year, with no regard for exclusion criteria.

AECOM also sought to measure the number of events that would be exempted from annual SAIDI totals on the basis of the IEEE standard, 1366-2003[94]. Across the UED network, the SAIDI threshold corresponding to the standard has been calculated as 4.7 minutes. AECOM calculated the SAIDI contribution from storm events for which the daily average SAIDI exceeded the 4.7 minute exclusion threshold. In practice, this meant that all storm events involving wind speeds above 91 kilometres per hour would fall into the excluded category, because the historical relationships suggested that these events typically give rise to a daily average SAIDI in excess of 4.7 minutes. The contribution of the more extreme events to total SAIDI was worked out to be 20 minutes. Hence, the overall impact of high wind days on unplanned SAIDI net of excluded events is eight minutes.

16.2.3 Formulation of performance targets

In accordance with the AER's Framework and Approach Paper and the STPIS, UED has used a five-year average of actual performance figures from 2005 to 2009 as the preliminary basis for setting targets for the next regulatory period. An average of performance figures across the UED network over five financial years is shown in Table 16-1 below, together with the source data for each year. The historical series representing reliability of supply measures have been re-calculated to give results that would have been recorded if the IEEE standard for a major event day had been in operation over the period. In other words, the data has been re-cast to give effect to the major event day exclusion criterion based on SAIDI. Before applying the new standard, the data was also expunged of the effects of the ESC exclusion regime, although the impact of exclusions caused by upstream incidents, such as transmission line failures and unplanned generator shutdowns was maintained.

[94] **IEEE (2004). IEEE Standard 1366-2003. IEEE Guide for Electric Power Distribution Reliability Indices. IEEE Power and Engineering Society, sponsored by the Transmission and Distribution Committee. Published by the Institute of Electrical and Electronics Engineers Incorporated. 14 May 2004.**

UED notes that targets for ETSA Utilities were based on average performance over three years and not over a full five-year period. In the Framework and Approach Paper for ETSA[95], the AER appears to have endorsed the use of a shorter time-frame.

Table 16-1: Targets derived from the AER exclusion criteria 4.02 minute threshold

Performance measure	Units	2005	2006	2007	2008	2009	Average
URBAN							
Unplanned (SAIFI)	Index	0.83	0.81	0.92	0.84	1.11	0.90
Momentary (MAIFI)	Index	1.31	1.11	0.97	0.94	0.98	1.06
Unplanned SAIDI	Minutes off-supply	49.59	47.44	54.21	50.38	69.22	54.17
RURAL							
Unplanned (SAIFI)	Index	1.68	1.48	1.36	1.45	1.56	1.50
Momentary (MAIFI)	Index	2.81	1.48	1.61	2.06	3.43	2.28
Unplanned SAIDI	Minutes off-supply	79.47	67.06	80.96	77.64	141.07	89.24
NETWORK							
Unplanned (SAIFI)	Index	0.96	0.92	0.99	0.95	1.15	0.99
Momentary (MAIFI)	Index	1.55	1.16	1.07	1.12	1.21	1.22
Unplanned SAIDI	Minutes off-supply	54.38	50.59	58.52	55.15	76.04	58.93
ENTIRE REGION							
Call centre performance	per cent	69.07	65.23	65.31	63.62	62.53	65.15
Street light performance	per cent	99.77	99.62	99.82	99.48	98.50	99.44

Source: UED calculations following Framework and Approach Paper (AER, 2009e1). The figures in the table will be subject to revision when full year results for 2009 are available.

UED proposes that the targets should remain constant over the five year regulatory control period. The assessment of performance against the targets will be undertaken systematically from calendar year 2011.

The first S-factor to be computed under the new STPIS will affect DUoS tariffs for calendar year 2013.

The historical performance data which underpins the values used to set targets will be updated when full year figures for 2009 become available. The revisions to the numbers will be undertaken well in advance of the release of a final decision by the AER.

95 AER (2008k3). Final framework and approach paper, ETSA Utilities, 2010-15. Australian Energy Regulator, November 2008.

16.2.4 Other factors affecting actual performance targets

Under the Rules UED is limited in the approach it can take to establishing performance targets. The Rules do not provide UED with an ability to forecast deteriorating performance, despite the advice received from independent experts AECOM. UED must forecast capital and operating expenditure in order to maintain or improve its reliability performance targets. Accordingly UED has included expenditure programs for both operating and capital related items to mitigate the likelihood of deteriorating performance due to climate change.

Although UED is unable to formally amend the targets for deteriorating performance there are other factors which are expected to materially affect the service being measured by the reliability of supply parameters, including:

- the impact of extreme heat, as analysed by AECOM and reported in AECOM (2009);
- the effects of high wind days on reliability of supply;
- load forecasting error;
- the impact of probabilistic planning; and
- the secondary effects of wind caused by the drought.

Full details of the effects are provided as an appendix to this Proposal.

16.3 Revenue caps

The raw S-factor components under the new scheme have been constrained to lie within particular bounds, thus limiting the potential upside (and the possible downside) for UED under the system. The caps proposed by the AER can be set out as follows:

- Telephone answering (call centre performance) and street light performance variables.
  - The raw S-factor components are constrained to lie within a range of -0.5 per cent and +0.5 per cent. Clause 5.2(b) of the STPIS sets out the individual customer service variable limit.
- The sum of the raw S-factors for telephone answering and street light performance.
  - The raw S-factor components are limited by lower and upper bounds of -1 per cent and +1 per cent respectively. Clause 5.2(a) of the STPIS set out the maximum revenue increment or decrement for all customer service variables in aggregate.
  - The cap for the sum of the CS variables seems superfluous in view of the individual CS limits.
- The overall cap applicable to the sum of raw ROS and CS S-factors.
  - The sum of the S-factor components is limited by lower and upper bounds of -5 per cent and +5 per cent respectively. Clause 2.5(a) states that the maximum revenue increment or decrement for the scheme components in aggregate will be 5 per cent.

UED does not oppose the setting of S-factor revenue caps for the individual customer service measures. However, the business has taken the position that a cap of ±5 per cent of revenue on the sum of ROS and CS components is too high. In particular:

a) UED will be exposed to the risk of wide revenue fluctuations. Volatility in the S-factor would potentially cause large variations in distribution tariffs from year to year, an outcome which would result in unpredictable costs to consumers. It seems unlikely that consumers would be supportive of the uncertainty inherent in such a regime.

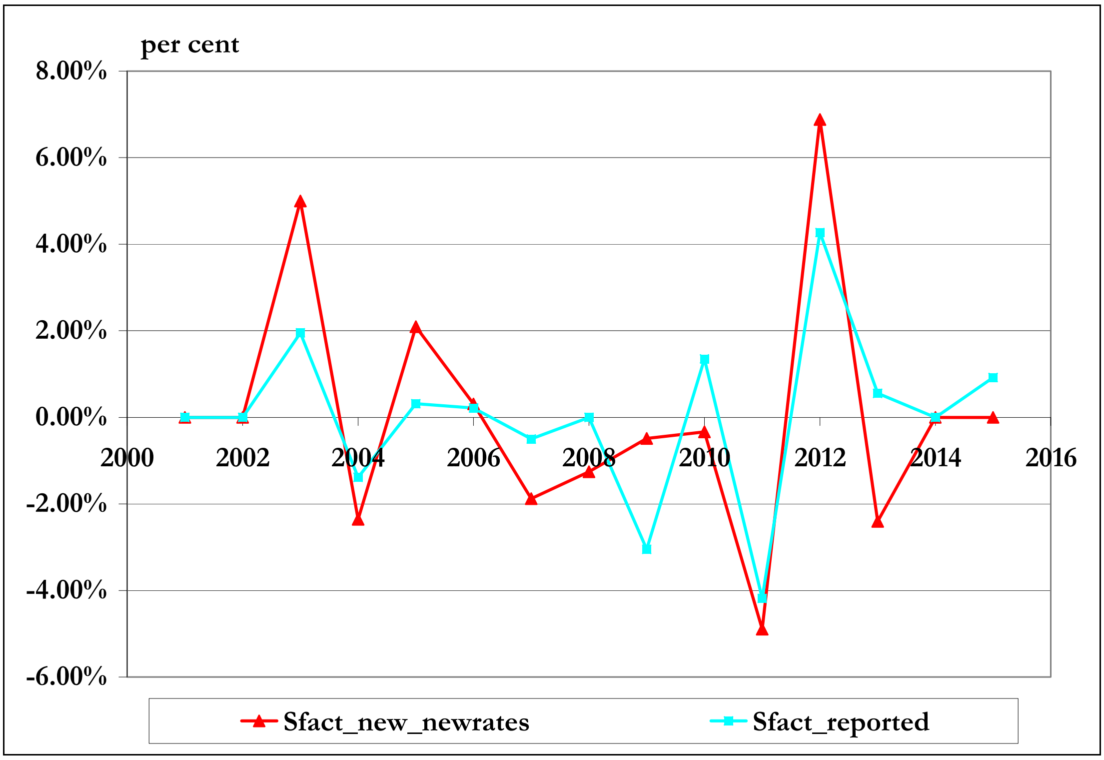
b) UED believes that a lower cap on revenue-at-risk of ±3 per cent is appropriate and capable of meeting the objectives of the scheme as described in section 1.5 of the STPIS paper.

UED believes that there is currently limited scope to improve reliability across its network on a sustained basis. A major expenditure programme would need to be undertaken to cause enduring improvements to reliability, and this programme would necessarily entail the underground placement of key parts of the network or significant additional investment in asset replacement to increase the resilience of the overhead network. Reliability is strongly influenced by seasonal and cyclical factors which cannot readily be controlled by the business.

Seasonal variations in reliability have the potential to cause wide fluctuations in tariffs from one year to the next. The S-bank mechanism may prove inadequate in smoothing out revenue, and therefore tariffs, particularly if two consecutive years of adverse weather (causing poor reliability performance) are followed by two years of favourable weather (giving rise to strong performance on reliability measures). UED has modelled the STPIS using historical data, and has found that, with a 5 per cent overall revenue cap, there is greater volatility of the S-factor under the new scheme than under the old scheme.

Figure 16-1 compares results under the existing S-factor scheme with the outcomes that would have been obtained if the STPIS had been applied over the same period. The simulations under the STPIS have taken all of the scheme's features into consideration, including the ±0.5 per cent cap on individual customer service variables, the ±1 per cent cap on customer service variables in aggregate, and the overall revenue cap of ±5 per cent.

Figure 16-1: S-factor results under current and proposed schemes



The diagram shows clearly that S-factor percentage results are more volatile under the STPIS than under the current, ESC scheme. A cap of ±3 per cent applied to the sum of the raw S-factor components would help to dampen the significant oscillations in the bonus and penalty payments.

UED firmly believes that the lower cap would assist in achieving a better balance between two of the key objectives of the scheme, which are set out in clause 6.6.2(b)(3) of the Rules which are to be applied not only in developing but in *implementing* the scheme:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs; and
- the need to ensure that the incentives are sufficient to offset any financial incentives which the service provider may have to reduce costs at the expense of service levels.

Moreover, a lower cap would also play a valuable role in serving to ensure that the financial viability of the electricity distribution industry in Victoria is not undermined. The STPIS with a lower cap would be consistent with the national electricity objective outlined in section 7 of the NEL.

16.4 Incentive rates

The AER has published its method for calculating incentive rates in full and provided worked examples showing its operation. UED proposes to accept the methods described in sections 3.2.2 and 5.3.2 of the STPIS.

Clauses 3.2.2(h) and (i) and Appendix B of the STPIS set out how the incentive rates should be calculated for unplanned SAIFI and unplanned SAIDI respectively. Clause 3.2.2(k) of the STPIS states that the rates should be calculated at the commencement of the regulatory period, with intent to apply them over the duration of the period.

The indicative values of the incentive rates, evaluated in accordance with the outlined approach, are shown in Table 16-2. The incentive rates applicable under the existing ESC scheme are shown for purposes of comparison.

Table 16-2: Indicative incentive rates for ROS variables, 2011 to 2015

	Units of measurement	ESC rates (% / minutes)	AER method (% / 0.01 interruptions)
	Network type	2008 to 2011	2012 to 2016
Unplanned SAIDI	Urban	8.89%	8.60%
Unplanned SAIDI	Short Rural	0.37%	1.22%
Unplanned SAIFI	Urban	5.15%	5.32%
Unplanned SAIFI	Short Rural	0.26%	0.79%

Source: UED calculations following AER approach. The incentive rates under the ESC scheme are taken from Table 3.2, volume I, ESC (2005a).

The incentive rates will need to be re-calculated when the AER hands down its determination for the Victorian electricity distributors. The indicative values suggest that the rates are higher under the STPIS than under the ESC scheme. However the incentive rate for unplanned SAIDI in urban areas has fallen marginally, according to the calculations performed by UED. Overall, the proportion of revenue at risk is potentially higher under the STPIS, by a significant margin.

The calculated incentive rates draw upon values of the following series:

- The performance targets for unplanned SAIDI and SAIFI.
- The estimated Value of Customer Reliability (VCR) as set out in Charles River Associates (CRA) report for VENCorp, which is $50,905 (January 2011 prices).
- Average annual energy consumption has been estimated at 6,767,000 MWh for urban feeders, and 990,000 MWh for short-rural feeders.
- An estimate of the annual revenue requirement over the five year period from calendar 2011 to 2015.

UED has not commissioned quantitative research to evaluate consumer preferences and therefore derive an estimate of willingness-to-pay for reliability improvements. Therefore, UED will not be proposing an alternative to the CRA estimate of VCR, although UED is nonetheless concerned that comparatively small sample sizes were used in the surveys undertaken by CRA in 2002 and 2007.

UED proposes to apply the incentive rate of -0.04 per cent for the telephone answering parameter for the regulatory control period. Consequently, UED is not putting forward an alternative method for setting the telephone answering incentive rate. UED also expects to apply an incentive rate of -0.02 per cent for street lights, if street light performance is included as a parameter.

UED concurs with the AER that incentive rates should be fixed for the duration of the regulatory period. UED will also apply the weightings in Table 1 on page 11 of the STPIS to calculate the incentive rate for each parameter. The weightings are 0.97 for urban areas and 0.92 for rural areas.

16.5 Inclusion of public lighting and MAIFI

16.5.1 Public lighting

Along with the other Victorian electricity distributors, UED has been systematically compiling monthly data on street light performance since November 1994. The data series gathered can be itemised as follows:

- number of street lights in aggregate;
- number of non-functioning street lights within the period;
- number of street lights not repaired within the required time frame (by the due date);
- number of payments under a GSL scheme; and
- the value of payments under a GSL scheme.

On the basis of the historical data currently available, UED believes that the proportion of lights not repaired by the due date is the only public lighting variable that is suitable for incorporation in the STPIS.

UED does not support the inclusion of public lighting as a customer service measure because the company already achieves a high standard in terms of the timeliness of repairs. When measured on an annual average basis, the share of street lights repaired by the due date has been above 98 per cent in every year since 2000. The GSL scheme provides UED with an incentive to maintain service levels rather than to seek to curb costs. Consequently, the additional incentive effects arising out of the adoption of street light performance targets in the STPIS would only be modest.

16.5.2 MAIFI

The AER has proposed that MAIFI should be included as a reliability of supply measure in the STPIS[96]. MAIFI is a component of the existing S-factor scheme, having first been calculated for the 2008 calendar year. A momentary interruption has been described as a break in the customer's supply of one minute or less.

MAIFI is discussed in the STPIS, but was not built into the financial model developed by the AER. The AER has proposed that the incentive rate for MAIFI should be set at 8 per cent of the incentive rate for unplanned SAIFI (see clause 3.2.2(j)(1)). This is a method which

[96] **AER (2009e2). Electricity distribution network service providers. Service target performance incentive scheme. Australian Energy Regulator. May 2009.**

essentially follows current practice. UED understands, from clause 3.2.2(j)(2), that an alternative incentive rate, which reflects customer willingness to pay for a reduction in MAIFI, would also be considered, provided that due justification is given.

UED opposes the use of MAIFI as an ROS measure, because of the observed trade-off between MAIFI and unplanned SAIFI. Experience suggests that it is not practical to aim for reductions in both measures. UED has implemented strategies, such as a longer time interval before the restoration of power by automatic reclose devices, which have the effect of bringing down SAIFI while actually pushing up MAIFI.

16.6 Exclusions

The STPIS sets out a classification of events for which distributors can seek exemptions from the S-factor scheme and from guaranteed service level (GSL) payments. UED is pleased that the same list of disqualifying events has been applied to the S-factor penalties/rewards scheme as to the GSL compensation scheme. The exclusions are written down formally in sections 3.3 and 6.4 of the STPIS.

The exclusion criteria to be applied under the new scheme are essentially the same as those currently in use and have been set out by the AER as follows:

1) load shedding due to a generation shortfall;
2) automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition;
3) load shedding at the direction of the National Electricity Market Management Company ("NEMMCO") (now "AEMO") or a system operator;
4) load interruptions caused by a failure of the shared transmission network;
5) load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning; and/or
6) load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.

If an interruption on a DB's network is caused by any of the aforementioned events, then there is no applicable reward or penalty under the S-factor scheme.

An event may also be exempted where daily unplanned SAIDI for the DB's distribution network exceeds the major event day boundary.

UED is broadly supportive of the new standard for a major event day which is based on SAIDI.

Appendix D of the STPIS outlines the method according to which the major event day threshold is to be calculated. The 2.5 beta method, as the approach is termed, is an internationally accepted method (detailed in the IEEE 1366:2003 standard) for normalising reliability performance data. The impact of extreme events, which are beyond the control of a DNSP, is eliminated by this method.

UED has long been in favour of an objective major event day definition, with the company engaging pro-actively in an ENA sub-committee on reliability and power quality control.

UED does not believe that the major event day threshold should be updated annually for each year of the forthcoming regulatory period as detailed in appendix D of the STPIS. UED considers that the threshold should remain fixed over the forthcoming period because the performance targets will also remain unchanged. Empirical work undertaken by UED has shown that the calculated targets are sensitive to the value of the exclusion threshold that is applied.

17. Efficiency Benefit Sharing Scheme

Key messages

- UED's proposed approach to the Efficiency Benefit Sharing Scheme ("EBSS") accords with the AER's published scheme and the Rules subject to one important change. 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 EBSS. In addition, UED has proposed that the costs of non-network alternatives and pass-through events are also excluded from the scheme.
- UED notes that its capitalisation policy has not changed in the current regulatory period, and is not expected to change in the foreseeable future. If the policy does change, however, appropriate adjustments to the EBSS calculations will be made in accordance with the scheme.

17.1 Regulatory requirements and chapter structure

The AER has published an EBSS in accordance with clauses 6.16 and 6.5.8 of the Rules. The EBSS provides a fair sharing of cost efficiencies between the DNSP and its customers.

The EBSS is the successor scheme to the efficiency carryover scheme, which was first implemented in Victoria by the Office of the Regulator-General in 2001. Further details of the efficiency carryover scheme are provided in Chapter 10 of this Regulatory Proposal.

Clause S6.1.3(3) of the Rules requires that a Regulatory Proposal must contain:

> " A description, including relevant explanatory material, of how the Distribution Network Service Provider proposes the efficiency benefit sharing scheme should apply for the relevant regulatory period."

In complying with this Rules requirement, UED is required to take account of the following documents:

- the Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme, published by the AER in June 2008 (EBSS); and
- the AER's Framework and Approach paper (published in May 2009), in which the AER sets out its likely approach to the EBSS for this review.

The EBSS sets out a number of matters for the DNSP to consider in its Regulatory Proposal, which are addressed in this Chapter as follows:

- Section 17.2 sets out UED's proposed uncontrollable cost categories, which will be excluded from the EBSS;
- Section 17.3 addresses the issue of measuring efficiency gains, noting that UED's forecast operating expenditure already includes significant cost efficiencies.

- Section 17.4 describes UED’s proposed the growth adjustment mechanism and the efficiency carryover period;
- Section 17.5 discusses capitalisation policy issues with respect to the EBSS;
- Section 17.6 comments on the exclusion of non-network alternatives from the EBSS; and
- Section 17.7 discusses the treatment of pass-through events for the purpose of the EBSS.

17.2 Proposed uncontrollable cost categories

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.
>
> A DNSP must justify a proposal to exclude cost categories to the AER. A DNSP must also not seek to exclude categories of costs that could otherwise be regarded as controllable costs, for example, labour and materials costs and service provider costs. Proposed adjustments to the forecast opex will only be accepted by the AER if they are for changes in costs the AER considers are uncontrollable and will not adversely impact the operation of the EBSS.”

In light of the above requirements, UED proposes that costs which fall into the groupings shown below should be classified as uncontrollable for the purposes of the EBSS. The categories are:

- 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.

The first three categories of uncontrollable costs are drawn from the final distribution determination for NSW Determination. In the main, UED endorses the explanatory material advanced by the NSW DNSPs and accepted by the AER to justify the treatment of these cost categories as uncontrollable. Specifically, the management of these particular costs is beyond a distributor’s normal business activities.

In addition to the uncontrollable cost categories accepted by the AER for the NSW DNSPs, UED also proposes that pass through costs below the materiality threshold should also be excluded. The rationale for UED’s proposed approach is that pass through costs are designed to address cost changes that are beyond the company’s control. Whilst it is reasonable to apply a materiality test to the pass through of such amounts to customers, it is not appropriate to apply the same materiality threshold in calculating the EBSS payments. In the absence of UED’s proposed exclusion, UED may be exposed to an efficiency penalty (or bonus) as a result of, for example, a change in tax law or a change in vegetation management regulations. There is no economic or commercial justification for UED and customers to face penalty or bonus payments in respect of cost changes that are evidently unrelated to the company’s performance. For this reason, it is appropriate to exclude pass through amounts that do not satisfy the materiality threshold.

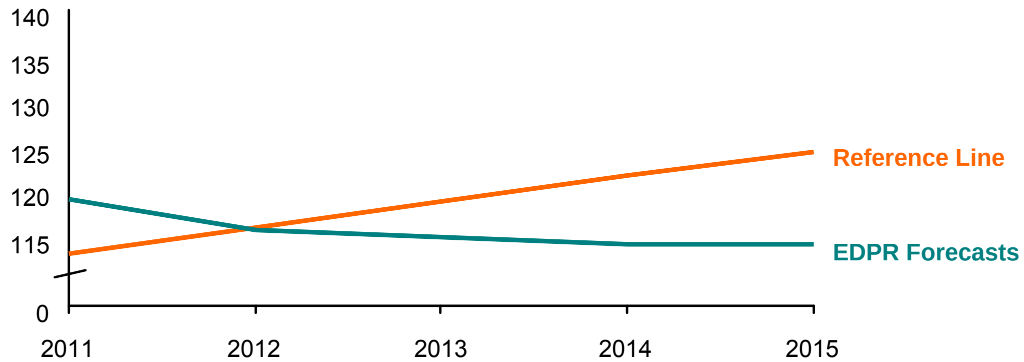
17.3 Treatment of efficiency gains and losses

As previously noted, UED has been subject to an efficiency carry-over mechanism since 2001. The EBSS, like the efficiency carry-over mechanism, is essentially an arrangement for sharing efficiency gains between a distributor and its customers. UED strongly supports the objectives of the EBSS, noting that UED has responded positively to the incentives provided by its predecessor scheme.

An efficiency gain is defined in the EBSS as a reduction in operating expenditure in any one year relative to forecast. The apportioning of the gains occurs because distribution businesses retain the savings from any under-spending within the regulatory period, and these benefits are then transferred to customers in the following and subsequent regulatory periods through lower projected levels of operating expenditure (and therefore lower prices). The EBSS allows approximately 30 per cent of the efficiency gains to be retained by the distributor through a bonus payment arrangement.

As explained in section 3.2 of this Regulatory Proposal, UED’s operating expenditure forecasts reflect the outcome of UED’s business re-structuring and a competitive tender process which is expected to deliver significant efficiency gains over time, as shown in Figure 17-1 below.

Figure 17-1: UED's five year comparisons (OPEX) – DUOS opex only



In effect, UED is planning to deliver significant efficiency gains compared to a projection of the status quo, which is reflected in the reference line in the above figure. 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 proposes 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's proposed approach ensures that the concept of 'fair sharing' efficiency gains is properly reflected in the operation of the EBSS.

17.4 Demand growth adjustments and carryover period

In section 2.3.2 of the EBSS, the AER states that for the purposes of calculating carry-over amounts, operating expenditure projections must be adjusted for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period. These adjustments must make use of the relationship between demand growth and expenditure that was established when developing the operating expenditure forecasts in the first instance. Adjustments should also only be applied to the components of operating expenditure which are directly affected by growth.

UED notes that its operating expenditure forecasting methodology has not explicitly applied growth factors to produce the forecast expenditure. Instead, UED's forecasting methodology, described in Chapter 5, has adopted a detailed assessment of UED's expenditure requirements, driven substantially by UED's asset management plan and its business transformation through Project 7/11. Given the forecast methodology employed by UED, in order to comply with the requirements of the EBSS it is necessary to employ an alternative growth adjustment.

UED believes that changes in variables such as customer numbers, peak load, and energy consumption do have a bearing on operating expenditure. In the event, therefore, that the outturn values of these variables differ from the amounts forecast, UED believes that it is appropriate to make revisions to the operating expenditure projections for the purpose of applying the EBSS.

Therefore, for the purpose of calculating efficiency carry-over amounts accumulated or accrued over the 2011 to 2015 regulatory period, UED is proposing to employ the growth adjustment formulae developed by the ESC. A description of this growth adjustment is provided in Chapter 10 of this Regulatory Proposal and appendix H-5, and is therefore not repeated here. However, UED notes that the growth adjustment was developed in accordance with partial-factor productivity analysis, and therefore serves to ensure that reasonable adjustments for growth will be made at the end of the regulatory period. In particular the growth adjustment coefficients were derived using industry-wide data.

In addition to the growth adjustment described above, UED proposes the application of a five regulatory year carry-over period, which is consistent with section 2.3.3 of the EBSS.

17.5 UED capitalisation policy

Distribution businesses are obliged to report changes in capitalisation policy to the AER. At this stage, UED does not expect any change to the policy in either the remainder of the current regulatory period or during the next regulatory period. If revisions to the policy are brought about, however, then UED will act in accordance with clause 2.3.2 of the EBSS by:

- adjusting the forecast operating expenditure used to calculate the carryover amounts so that the forecast operating expenditure is consistent with the capitalisation policy changes; and
- providing a detailed description of the changes in capitalisation policies and a calculation of the impact of those changes in capitalisation policy on forecast and actual operating expenditure.

17.6 Exclusion of non-network alternatives

In section 2.3.2 of the EBSS, the AER states that all operating expenditure spent on non-network alternatives will be exempt from consideration under the EBSS. In other words, the budgeted and actual operating expenditure sums used to calculate carry-over gains and losses under the EBSS will not incorporate any allowance for spending on non-network alternatives.

In its expenditure forecasts, UED is expecting to devote only a small proportion of total operating expenditure to non-network alternatives. Most recurrent outlays on non-network options will be in respect of the demand management innovation allowance (DMIA). UED is also proposing that the DMIA be excluded from the operation of the EBSS. The forecasts for spending on the DMIA are presented in Chapter 5 and 18.

17.7 Treatment of recognised pass-through events

In section 2.3.2 of the EBSS, the AER has set out its policy regarding the treatment of approved increases or decreases in actual operating spending associated with recognised pass-through events. The AER has indicated that clearly identifiable pass-through components will not qualify for inclusion in the EBSS. Accordingly, the AER states that any increase or decrease arising from the operation of pass-through arrangements should be exempted from the calculation of carry-over gains or losses.

UED concurs with the AER and believes 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. As noted above, UED also considers that a 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 are presented in Chapter 19 of this Regulatory Proposal. Further information on the EBSS and demand growth adjustments is provided in appendix H-5, which examines the relationship between the EBSS and partial factor productivity measures.

18. Demand Management and the DM Incentive Scheme

Key messages

- 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. The firm would like to extend the benefits of AMI into the demand management arena.
- UED supports the DMIS as it provides a stimulus to deliver demand management initiatives in circumstances where there may be doubts about the commercial viability of particular measures.
- UED acknowledges and accepts the approach outlined by the AER in its DMIS for Victoria and in its Framework and Approach Paper.
- The AER has foreshadowed that the DMIS allowance to be provided to UED over the next regulatory period is likely to be $400,000 per annum. UED has therefore incorporated the ex-ante innovation allowance of $400,000 (in nominal terms) per annum as a revenue increment for the DMIS building block component.
- In UED's view, this allowance is of sufficient magnitude to enable the company to undertake a number of small scale demand management projects in each year of the next regulatory period.
- UED aims to undertake trials of direct load control ("DLC") and critical peak pricing ("CPP"). The participation of customers with AMI meters will be required. UED will also work with demand-side aggregators to develop bespoke demand management solutions in particular regions.
- It is important to realise that the success of individual demand management initiatives will depend in part on overcoming technical challenges and managing the risks of unsatisfactory performance.
- The possibility remains 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.

The structure of this chapter is as follows:

- Section 18.1 discusses the proposed national framework for distribution network planning.
- Sections 18.2 and 18.33 discuss UED's objectives and strategies in relation to demand management.
- Section 18.4 discusses the scope for demand management programmes which leverage off AMI capabilities and equipment.

- Section 18.5 refers to the demand management programmes which will be put in place by UED.
- Section 18.6 provides an overview of the DMIS and sets out UED's proposed approach to implementation of the scheme in the forthcoming regulatory period.

18.1 Framework for distribution network planning and development

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[97]. The AEMC has submitted its report to the Ministerial Council on Energy (MCE) in conjunction with the draft Rules which encapsulate the various recommendations (AEMC, 2009j1). UED anticipates that the Rule change request will be acted upon and that the draft Rules will be implemented.

The AEMC intended that the demand side engagement strategy should be comprised of three components:

- a demand side engagement facilitation process document;
- a public database of proposals and case studies; and
- a register of parties with an interest in participating in demand side projects. Each DNSP would maintain its own copy.

The facilitation process document is expected to contain extensive detail about the manner in which distributors assess potential non-network solutions, and the procedures that are followed to engage, consult, and negotiate with potential non-network providers. The document would also discuss the principles which the DNSP considers when determining payments for non-network solutions, and the method to be used for working out avoided customer TuOS charges, in accordance with clause 5.5 and clause 5.6.2(k1) of the Rules.

Demand management is one of a number of possible non-network solutions which UED will consider when evaluating investment alternatives in the context of the newly developed regulatory investment test for distribution (RIT-D). The RIT-D is an extended project assessment and consultation process for distribution investments which has been designed to replace the current regulatory test. Implementation of the RIT-D was another of the recommendations to emerge from the final report on distribution network planning and expansion. A $5 million threshold has been set for the RIT-D, with projects costing in excess of this amount expected to be subject to the test. The threshold value would be applied to the estimated capital cost of the most expensive option that is both technically and economically feasible, and capable of addressing the relevant identified need.

A feature of the RIT-D is a requirement that distribution businesses assess:

- the reasons for the investment; and

[97] **AEMC (2009j1). Review of National Framework for Electricity Distribution Network Planning and Expansion, Australian Energy Markets Commission. Final Report, 23 September 2009, Sydney.**

- the material potential for the use of non-network options to either obviate or defer the need for the particular investment, which was aimed at remedying a network deficiency or inadequacy.

Under the proposed new framework, distribution businesses are expected to actively consider the possible application of non-network methods at the specification threshold test ("STT") stage. If the *prima facie* examination suggests that a non-network approach is feasible, then the distributor has to publish its STT and the project will progress to a specification phase.

At the project specification stage, the distribution network service provider is obliged to consult publicly on the range of options, both network and non-network, that are capable of meeting the identified need. The DNSP must use its best endeavours to understand the potential network or non-network solutions that are capable of rectifying an emerging or imminent imbalance.

The AEMC has envisaged that non-network providers would have an opportunity to put forward proposals to meet the perceived need during the project specification phase. Distribution businesses would prepare a project specification report and invite submissions. The prescription in the Rules of this part of the process would minimise the likelihood that alternative credible options are overlooked, and would facilitate the discovery and adoption of the most efficient solution to the identified need.

The publication of a project specification report would help to ensure that there is transparency in respect of:

- the desired characteristics of a non-network proposal; and
- the manner in which a DNSP assesses non-network proposals which it receives.

The AEMC believes that communication between distributors and non-network providers will be enhanced, and that there will be an increased uptake of non-network solutions in situations where these alternatives can efficiently meet identified needs.

18.2 Demand management initiatives proposed by UED

UED is keen to develop demand management solutions which are appropriate, bearing in mind the load profiles and customer growth patterns in its region. 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.

Distribution businesses are currently restricted from providing services to the National Electricity Market such as the provision of reserve capacity and frequency control. UED believes that demand management should be incorporated into the reliability and emergency reserve trader arrangements which provide support to the NEM. If the RERT role were expanded in this manner, then the Australian Energy Market Operator (AEMO) would be able to use demand management as a means of intervening in the market to maintain supply reliability. The business case for demand management would consequently be enhanced.

18.3 Strategies for demand management

There are three principal elements to the demand management strategy which has been devised by UED. Firstly, UED plans to develop and deliver projects which conform to the requirements of the Demand Management Incentive Scheme (DMIS), described below. 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). Secondly, UED proposes to instigate peak demand management programmes which leverage off the capabilities offered by the Advanced Metering Infrastructure (AMI) project. Thirdly, UED will 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.

To-date, UED has been constrained in its efforts to instigate demand management via direct load control because of an absence of mechanisms such as ripple controls in domestic installations. The typical metering configuration in residential premises wired to the UED network is comprised of time switches. In spite of this limitation, UED has worked with demand-side proponents such as Energy Response in a bid to alleviate load constraints on critical parts of the network.

The assets put in place as a result of the roll-out of AMI will boost demand management by providing a platform for new initiatives, and by serving to re-invigorate existing approaches. A number of opportunities will become available to trial new schemes.

18.4 Demand management capabilities offered by interval metering infrastructure

The demand management capabilities offered by AMI can be itemised as shown in the list below:

1. **Critical Peak Pricing (CPP).** These are notifications from the retailer to the consumer, which are expected to be used several times per annum to reduce demand.

2. **Load control via the Home Area Network (HAN).** A home area network will allow in home displays and smart appliances to communicate with a smart meter so as to provide consumers with the information and control required to manage their power consumption and costs. Signals can be sent to devices such as air

conditioners, pool pumps and plug-in electric vehicles so as to cause demand reductions.

3. **Direct load control** using the load control contactor on the AMI meter. This method is used today for controlled loads (such as hot water and space heating), however the AMI meters offer additional capabilities such as remote configuration of the on-off times.

4. **Supply capacity limiting** can be used to reduce consumption at the premises, either as an emergency measure or as part of a retailer or distributor offering.

5. **Interval metering** will enable a distribution business to manage demand through tariffs such as "maximum demand tariffs".

AMI systems will create the potential for a suite of demand management capabilities that can be executed lightly or aggressively as demand events require. A distribution business will require demand management tools that allow for control, monitoring, forecasting and management of demand events, whether these are initiated by the distributor, retailer or other party.

As AMI meters become more widespread, UED will have an option to use load control to manage demand, either directly or indirectly via the HAN. In addition, the business will be able to use the supply capacity limiting feature of AMI meters to cap consumer demand during emergencies.

If interval metering were used to offer maximum demand tariffs, then the meter data management and billing systems would need to be configured to support such tariffs.

The support and involvement of retailers will be required for measures such as Critical Peak Pricing, Supply Capacity Limiting and Load Control via the HAN. These instruments of demand management will be available once the HAN and meter configuration service levels are included in the AMI mandate. New market processes, and mandated service levels would need to be put in place to allow the retailers to use the HAN capabilities.

18.4.1 The benefits of demand management achieved via AMI

UED can leverage off its investment in AMI, achieving reductions in peak demand and facilitating the deferral (or avoidance) of capital outlays that would ordinarily be required to bolster and augment the network. Provided that there is a reasonable level of co-operation between the parties, then UED will become aware of demand management events instigated by retailers, and will be able to pro-actively manage the network so as to ensure that large, and potentially abrupt, changes in loading conditions do not adversely affect network stability. In addition, network planners will gauge the overall responsiveness of electricity demand to the particular load reduction measures implemented, and will use the information for capacity planning purposes.

The limiting of supply capacity in emergency situations will enable consumers to remain on supply, even if only a limited power delivery basis. This form of demand-side response would be appropriately invoked during situations of transmission line failure. The end result is a better outcome for consumers in aggregate than what would otherwise be achieved through a rotating pattern of load-shedding. Selective load-shedding is currently the standard response adopted by market operators during periods of a major transmission line outage, or generator capacity shortfall.

18.5 Demand management measures to be implemented by United Energy

18.5.1 Direct load control

An absence of ripple control infrastructure across the UED distribution system has, to-date, hindered attempts by the business to experiment with direct load control (DLC) measures. However, the introduction of AMI meters presents a new opportunity to develop DLC methods and systems. United Energy has observed with interest the DLC pilot projects undertaken in other jurisdictions, and believes that there is scope to draw upon the experience acquired by other distributors. The business is keen to apply innovation funding from the DMIS to the investigation of DLC affecting air conditioners and other appliances.

UED believes that DLC can be readily used to alter the cycle times of air conditioners, and proposes to implement trials targeting residential and small commercial customers within its distribution area. Certain operational aspects of DLC would need to be investigated, specifically:

- the linkages between the AMI meter and the appliances in question, and the extent to which externally imposed controls can be overridden;
- the additional systems required to form an interface with retailers;
- any further upgrades that may be required to AMI meters;
- customer take-up rates of DLC, and the acquiescence of participating customers to external control;
- the recorded reduction in aggregate demand during heat wave conditions, particularly after a succession of hot days;
- the financial consequences for UED if the results from a small scale trail are replicated across its customer base; and
- the possible benefits to the electricity market as estimated under a regulatory test. The broader economic benefits may also be considered.

Although air conditioning is likely to be the principal focus of investigation, UED will also consider whether to run a separate trial which examines the efficacy of DLC in relation to other forms of power consuming equipment, including heat pumps, pool pumps, and domestic appliances.

The traditional use of DLC is in relation to hot water systems, and UED will explore this form of application. However, the business is aware that the Federal Government has mandated the phasing out of electric and gas hot water storage units from 2010. Consequently, the benefits to be gained from embarking upon a DLC programme in relation to water heating are unlikely to increase over time.

Energy Response, a demand-side aggregation business, has estimated that the cost of implementing DLC for air conditioning is approximately $300 for each residential dwelling with an AMI meter. The cost pre-supposes that a home area network (HAN) will be in place. The comparatively high figure is largely a consequence of a requirement to retrofit air conditioners, including recent models built to current specifications, with separate circuitry which enables the fan to operate separately from the compressor. The idea is that the fan can continue to rotate after a temporary compressor shutdown, induced by DLC. Energy Response has calculated that the capital costs of DLC, applied in this manner, would sum to approximately $1.1 million for each megawatt of demand reduction that could be brought to bear. This is reportedly higher than the average capital cost per megawatt of building and commissioning open cycle gas fired generation.

UED will investigate, through its proposed trial, whether these cost estimates are realistic and plausible, and whether alternatives can be considered which will not necessitate retrospective changes to the existing stock of air conditioning machines.

On account of the gradual phase-in of AMI metering devices, trials will, of necessity, be conducted in those areas of the United Energy distribution region which are already served by AMI meters. This may mean that the results obtained from a particular sample are not fully representative of the outcomes that would be reported if DLC were applied to a broader customer base across the network. The load reductions from the exercise of DLC will vary, depending on location, and the extent of load reduction may also be affected by ambient temperature conditions, and the temperature changes which are recorded over the preceding 48 hours.

UED will collect data showing:

- the customer acceptability of DLC events;
- the length of time over which the remote switching of air conditioners by a third party is tolerated; and
- the relationship between the uptake of DLC and other variables, such as the thermal insulation properties of the building or dwelling.

The trials will also reveal whether there are any systemic problems affecting the software and/or hardware elements used, and whether the switching devices are appropriate.

18.5.2 Critical peak pricing and time of use tariffs

Customers with AMI meters are currently being offered time-of-use (TOU) tariffs by United Energy, with the result that distribution charges vary according to the time of day. Higher distribution charges (in cents per kilowatt hour of delivered energy) are applicable during peak periods. UED expects that retailers will develop energy pricing models (for the actual electricity sourced) which show a diurnal variation to correspond with the time of day fluctuations in distribution tariffs. The peak rate for time of use distribution tariffs is typically around twice the average price, and is offset by an off-peak price which is below the average.

Under a critical peak pricing (CPP) model, the ratio of peak to average prices is about five, with the peak prices typically invoked for a few hours on a selected number of days, generally around 10 to 15 per annum. The responsibility for nominating peak events rests with the DNSP, and, as might be expected, a critical pricing period is generally activated when the network is operating at or close to its capacity. Customers with AMI meters would receive notifications via their retailer. A critical peak pricing period is designated with the objective of reducing demand and thus alleviating network constraints. There is no nomination of events under TOU tariffs, and so, for consumers, there is, arguably, a greater degree of certainty in terms of the application of the tariff. However, with both types of charging system, customers retain control of their loads and are presumed to respond to price signals. There is no remote switching of appliances or equipment by a distributor or third party.

UED is aware of research undertaken by Energy Australia in relation to the customer response to time of use (TOU) tariffs. Energy Australia (EA) undertook preliminary analysis and then engaged Charles River & Associates (CRA) to determine the likely impact of tariff based demand management initiatives on peak demand and energy growth. As is reported in Energy Australia's regulatory proposal (page 104, Energy Australia, 2008), there was a recorded reduction in demand (of approximately 1.1 per cent), coincident with the summer peak, for customers subject to TOU pricing initiatives, by comparison with customers subject to regular tariffs.

CRA reported that the growth in peak demand for customers on the EA network that were subject to TOU tariffs would be more modest than for customers signed up to other tariff classes. The impact of TOU pricing initiatives would be apparent by 2014. However, CRA cautioned EA against making significant revisions to its demand projections on account of the "structural impediments" associated with network pricing signals being passed on by independent energy retailers.

UED considers that there is a case for investigating the responsiveness of consumers to the price signals conveyed by TOU tariffs. An appropriate method of conducting the research would be to instigate a trial, involving volunteers. The results of the trial would be used to gauge the receptiveness of consumers to the TOU tariff structure. A preliminary assessment would also be made of the likely consumer reaction to a CPP tariff proposition.

At present, there is a perception among network businesses that the price signals from time-variant tariff models are an inadequate means of achieving a curtailment of demand during heat wave conditions. This view may be a shibboleth which will be refuted by the research. However, if peak period demand is price inelastic, such that network businesses cannot rely on customers to curb their consumption in response to price signals, then TOU tariffs, and, by extension a CPP regime, cannot be used as a substitute for network augmentation.

18.5.3 The use of back-up generators

A larger number of business customers connected to the UED network use diesel generators and other forms of generation to provide back-up power supply during power outages. These standby generators are not synchronised to the power system, and thus cannot provide inertia. A generator installation is normally designed to start running upon failure of the mains supply, and the objective is to restore supply to critical loads, which, in uninterruptible systems, may also be powered by back-up batteries in the immediate aftermath of an outage.

If generators were to be used to buttress the network during periods of peak demand, then significant modifications to the uninterruptible power configuration would be required. Supplementary electrical protection systems and controls would need to be installed so as to facilitate the safe operation of the network when the embedded generators are in active mode. There would also be hurdles to overcome with selected installations because of the noise and emissions consequences of standby generators, coupled with a regular requirement to refuel.

The use of back-up generators as a form of embedded generation would also necessitate the installation of an advanced metering solution which would record when a generator had made its capacity available to the NEM. Ordinarily, the capacity would only be used by the individual market participant, meaning the company or entity which owned the equipment. Contracts would also need to be structured to provide financial compensation (and therefore an incentive) to the generator owners, and to ensure that capacity is made available when it is required.

Orion Energy, a network business based in Christchurch, New Zealand, has a policy which encourages standby generators (rated up to 750kVA) to be connected to its network on a temporary basis. The generators can be synchronised or unsynchronised, and provide capacity which supports the network during periods of peak demand, in winter. The use of back-up generation also helps to maintain the continuity of electricity supply in adverse weather conditions.

At this stage, United Energy is not proposing to conduct a full investigation of the existence and availability of standby generation throughout the geographic areas which it serves. However, the use of standby generation will certainly be considered on a case by case basis, particularly in those regions where network constraints are beginning to emerge, or else are already apparent. UED will examine whether standby generation can be deployed as an alternative, in the short term, to network augmentation.

Back-up generation will also be considered as a part of a broader array of measures when a demand-side response package is being developed for a particular region.

18.5.4 Voluntary load control for large customers

A voluntary load control (VLC) programme is a demand management measure which aims to recompense business customers for voluntarily curbing their electricity consumption during periods of intense network usage. Voluntary load control programmes are generally geared towards medium and larger sized business customers. The types of load control strategy which are available under the programme include the installation and application of thermal energy storage devices, which use off-peak electricity. Ordinarily, participants are informed in advance about an up-coming load curtailment event, and are invited to curb demand. Businesses can then elect whether or not to respond. Conformance with the instruction or direction to diminish consumption is assessed on an *ex post* basis. The profile of electricity usage recorded by an interval meter is compared with a standardised, baseline load curve. An evaluation is then undertaken across all participating businesses with a view to ascertaining whether or not there have been declines in demand. VLC programmes are available through contracts between large customers and either distributors, retailers, or demand-side aggregators.

Technologies are emerging which offer scope for further development and inclusion in VLC schemes. Thermal storage air conditioning is a productive and promising form of innovation, but cannot be fitted retrospectively to existing buildings. The heat exchangers and other mechanisms need to be incorporated into the design of a building from the outset.

UED will assess in detail the merits of running VLC programmes across its network. It is possible that a trial will be run, however, at this juncture, UED has prioritised trials of direct load control and critical peak pricing.

18.5.5 Tailoring of demand-side response

The traditional approach to demand management generally involves the analysis of a range of possible methods which can be applied in a particular locality or along a specific section of the network. A targeted level of demand reduction is sometimes specified in advance of a suitable programme being devised. Various techniques can be employed to curtail demand, or to bring about an attenuation of demand growth, once a desired goal for load restraint has been identified.

Large energy users have tended to be the main participants in demand management programmes because distributors and retailers can contract with them at relatively low cost. Major customers with sound knowledge of the energy market have, in the past, been able to negotiate favourable demand-side response contracts, in which the consideration for foregoing demand has been specified at or near the prevailing spot market price. The technological platform provided by AMI meters has been discussed in section 18.4. A corollary benefit of AMI is that distributors and retailers will incur lower transactions' costs when formulating and implementing agreements with medium-sized business customers.

The benefits of demand management are manifested in terms of the postponement of network enhancement projects, such as zone sub-station refurbishments and/or the construction of new sub-transmission links. Savings are therefore realised through reductions in planned capital expenditure. However, a countervailing trend is the increase in operating spending which results from the need to research, develop and implement demand side response programmes.

UED intends to adopt a holistic approach to demand management, involving the investigation of all options in three different geographic areas, in each year of the next regulatory period. The indicative savings in capital expenditure and the additional operating spending required are shown below 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 terms.

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 anticipates that the investigation costs shown in Table 18-1 will be recoverable, either wholly or in part, through part A of the demand management incentive scheme (DMIS), which is discussed in section 18.6. The operating spending shown in the table has been incorporated into the baseline operating expenditure forecasts which have been proposed by UED as part of this regulatory proposal. The overall amount that has been budgeted for all demand management initiatives is $10 million over the forthcoming regulatory period.

United Energy understands that it will be able to recover revenue that is foregone as a result of the successful implementation of a project approved under Part A of the DMIS. The revenue losses would be consequential to the quantitative reductions in delivered energy volumes that are directly attributable to the take-up of the demand management project.

A tailored response to demand management means that the methods actually employed to bring down demand will vary depending upon the profile of users, and the options that are available in a particular area. Improvements in energy efficiency may prove to be a useful contributor to demand reductions. The types of energy efficiency initiative which will be useful in this regard are likely to 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 anticipates that customer education will be important, particularly in the commercial sector, because building owners and property managers are typically pre-occupied with overall energy usage, and greenhouse gas abatement, rather than with specific decreases in peak demand.

The benefits which accrue to customers from participation in demand-side programmes can be set out as follows:

- The option of a free, walk through, energy audit by signing an agreement to participate;
- 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.

18.5.6 Demand management programmes for agri-business customers

The rural customers in the UED distribution region are located primarily along the Mornington Peninsula. Agricultural enterprises comprise a reasonable share of rural business customers.

Energy Response has recently been awarded a Federal Government, Climate Ready Grant to develop and deploy a low cost technology platform which will facilitate the participation of small to medium sized enterprises (SME) in demand programmes. The award is valued at $0.5 million, to be provided over a two-year period. Energy Response has, in turn, outsourced research and development work to the CSIRO. The agency will examine the state of technology, communications systems and protocols, and back office systems.

UED would like to promote the uptake of demand management by customers in the agricultural sector. To that end, the business will form an alliance with Energy Response at or near the conclusion of its development of an SME technology platform. UED will ensure that practicalities are adequately addressed in the design and development of pilot projects, which are expected to be run from 2012.

18.6 Demand management incentive scheme

18.6.1 Introduction

United Energy is generally supportive of the approach taken by the AER to removing barriers to the implementation of demand management via the Demand Management Incentive Scheme (DMIS). UED believes that the DMIS provisions have the potential to:

- Facilitate the development of nascent demand management approaches, via the innovation allowance; and
- Provide compensation to DNSPs for the reduced sales volumes, and consequent lower revenues under the weighted average price cap (WAPC). A decline in energy sales volumes is a corollary of most, if not all, demand management initiatives.

The Framework and Approach paper for Victorian electricity distribution businesses[98] describes the manner in which the AER plans to implement the DMIS over the 2011 to 2015 regulatory period. The AER has also released its final decision on the DMIS[99] and a final version of the paper which describes the workings of the scheme[100]. Both documents covering the DMIS have been prepared specifically for Victorian electricity distributors, however, the scheme in Victoria bears a strong resemblance to that expected to operate in other jurisdictions.

18.6.2 Requirements of the National Electricity Rules

Clause 6.4.3(a) of the Rules provides for the use of the building blocks approach when assessing the annual revenue requirement (ARR) of a DNSP for each regulatory year of the next regulatory control period. Clause 6.4.3(a) also specifies the components of the building block approach, and one of these is comprised of the revenue flows (increments and decrements) for the year arising from the application of the various schemes – the efficiency benefit sharing scheme (EBSS), the service target performance incentive scheme (STPIS), and the demand management incentive scheme (DMIS). The schemes are

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[98] **AER (2009e1). 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.**

[99] **AER (2009d2). Final Decision. Demand Management Incentive Scheme. Jemena, Citipower, Powercor, SP Ausnet and United Energy. Australian Energy Regulator. April 2009.**

[100] **AER (2009d3). Demand Management Incentive Scheme. Jemena, Citipower, Powercor, SP Ausnet and United Energy. Australian Energy Regulator. Version 1, 23 April 2009.**

mentioned at paragraph 6.4.3(a)(5), while the Rules stipulate that the increment or decrement is to be calculated in accordance with clause 6.4.3(b)(5).

Clause 6.6.3 of the Rules allows the AER to develop, in accordance with the distribution consultation procedures in clause 6.16 of the Rules, a demand management incentive scheme (DMIS). In April 2009, the AER published a DMIS for the Victorian distribution businesses in accordance with these provisions. The objective of the DMIS, as stated in AER (2009d3) (page 2) is:

> " …to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way."

The AER's Framework and Approach Paper (AER, 2009e1), describes the manner in which the AER plans to implement the DMIS over the 2011 to 2015 regulatory period. In effect, the Framework and Approach Paper confirms the approach set out in the DMIS for Victoria.

Other references to the DMIS are in clauses 6.3.2(a) (3) and 6.12.1(9) of the Rules. Section 6.3.2(a) mentions the contents of a building block determination, and states that the determination should specify various components, including the manner in which the various schemes (the EBSS, STPIS and DMIS) are to apply over a regulatory control period. The schemes are actually itemised in paragraph 6.3.2(a) (3). Clause 6.12.1 notes that a distribution determination is predicated on a number of constituent decisions by the AER. Amongst the constituent decisions is a ruling, in paragraph 6.12.1(9), on how the applicable schemes should apply to the DNSP.

Schedule S6.1.3 of the Rules sets out the additional information and matters pertaining to the building block proposal which a DNSP is required to submit to the AER. Clause S6.1.3(5) states that a Regulatory Proposal must include a description of how the DNSP proposes the DMIS should apply for the relevant regulatory period.

The AER has developed a DMIS, in accordance with clause 6.6.3 of the Rules, to apply to Victorian electricity distributors during the next regulatory control period. The Victorian DMIS appears to be similar, in terms of its design and content, to the schemes which are slated for application in Queensland and South Australia.

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.

In respect of the drawdown of its allowance under Part A, a DNSP has the flexibility to select an expenditure profile which meets its needs. In particular, any under-spending in one year can be carried forward to later years. However, under the DMIS the value of any accumulated under-spending at the end of the regulatory period is not available to be transferred into the subsequent regulatory control period.

UED understands that the foregone revenue recoverable under Part B will be limited to revenue forsaken within the regulatory control period in which the DMIS applies, and does not include revenue given up in previous or future regulatory periods. This limitation is discussed in section 3.2.1 of the DMIS paper (AER (2009d3))..

The outcomes of the DMIS will be considered by the AER through an annual review process within the regulatory control period to which it applies, and an assessment of the DMIS will be made when considering the AER's application of demand management incentive schemes in the subsequent regulatory control periods. For DNSPs which wish to utilise it, there is an optional up-front, indicative approval process at the commencement of each regulatory year for planned expenditure under the DMIA. Where the DNSP's proposed expenditure is approved in principle, and the DNSP undertakes expenditure that does not differ in substance and/or form from that envisaged at the beginning of the regulatory year, the AER expects that the expenditure would be approved as part of the ex-post assessment.

In the Framework and Approach Paper prepared for Victorian electricity distributors (AER, 2009e1), the AER has set out what it considers to be an appropriate annual allowance for each distribution business. The DMIA has been based upon a comparison of the annual average revenue allowance for each DNSP during the 2006 to 2010 regulatory period.

Table 18-2 below shows the AER's view on the likely DMIA amounts for each Victorian Distribution Business, as set out in the AER's Framework and Approach Paper (AER, 2009e1).

Table 18-2: Expected annual DMIA amounts for Victorian distributors

DNSP	Likely DMIA amount ($ nominal)
Jemena	$200,000
Citipower	$200,000
United Energy	$400,000
SP AusNet	$600,000
Powercor	$600,000

Source: Section 6.8, Table 6.2 Framework and Approach Paper for Victorian electricity distribution businesses (AER, 2009e1).

Under the proposed arrangements, a total of $10 million will be allowed as DMIA expenditure by the Victorian distribution businesses over the next regulatory period. As noted in Table 18-2 above, the amount available to UED will be $400,000 per annum. In UED's view, this allowance is of insufficient magnitude to enable the company to undertake a comparatively small scale demand management project in each year of the next regulatory period.

18.6.3 UED's proposed approach to DMIS

United Energy is broadly supportive of the intended application of the DMIS by the AER.

In terms of the operation of the DMIS, UED acknowledges and accepts the approach outlined by the AER in its DMIS for Victoria and in its Framework and Approach Paper. In particular, UED accepts that:

- Part A of the DMIS, being the DMIA, should take effect over the 2011 to 2015 regulatory period;
- there will be flexibility in terms of the timing of the drawdown of the DMIA.; and
- the revenue that is 'renounced' through reductions in the volumes of electricity sold, which can be ascribed directly to initiatives taken under the DMIS, will be available to be re-claimed under Part B of the scheme.

The AER has had regard to NER criteria when considering the mode of application of the scheme to Victorian distributors.

UED is aware that once data becomes available for the final regulatory year of the regulatory control period, then the AER will calculate a total carry-over amount, drawing upon the results of the annual assessments discussed in section 3.1.4 of the DMIS paper[101]. The carry-over amount under Part A will take into consideration:

- The unspent value of the allowance, or any allowance not approved over the 2011 to 2015 period; and
- The time value of money accrued or lost as a result of the expenditure profile chosen by UED.

United Energy understands that information for the 2015 regulatory year will not become available in time to be incorporated into the Regulator's distribution determination for the subsequent regulatory control period (which, tentatively, will run from 2016 to 2020). Hence, the final carry-over amount under Part A will be deducted from or added to allowed revenues in the second regulatory year of the next regulatory period.

UED also recognises that the approved revenue foregone will be returned to the business in the form of a single adjustment to be made in the second regulatory year of the subsequent regulatory period. The adjustment will take place in conjunction with the correction which is expected to occur in the context of Part A.

Finally, UED believes that it is appropriate to sound a cautionary note with respect to the research into and trials of demand management technologies and schemes. Although the firm is committed to, and remains sanguine about, the implementation of projects discussed in section 18.5, there are business risks associated with the introduction of new methods and technologies, and these may only be mitigated in part by the DMIS. The possibility remains that some demand management projects may fail to yield the expected benefits in terms of, say, an easing of peak loading at critical times. Furthermore, other projects may provide benefits, in terms of load curtailment, but not within the foreshadowed timeframes, or within the narrow time horizon of a regulatory control period.

[101] **AER (2009d3). Demand Management Incentive Scheme. Jemena, Citipower, Powercor, SP Ausnet and United Energy. Australian Energy Regulator. Version 1, 23 April 2009.**

18.6.4 DMIS component of post-tax revenue model

Pursuant to clause 6.4.3(a)(5) of the Rules, UED has included a revenue increment of $10 million (in real 2010 values) for the DMIS building block component. 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.

The forecast for operating expenditure on demand management projects is provided below in Table 18-3

Table 18-3: 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 real 2010 terms.

19. Pass through events

Key messages

- Pass through provisions for defined events and nominated events should be applied to both standard control and alternative control services.
- The Rules provide strong incentives to regulated businesses to take all reasonable measures to mitigate the impact on consumers of a pass through event that will result in an increase in costs.
- 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. UED agrees with the AER's view that the administrative costs of assessing a cost pass through application may be low.
- 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 proposes that the following specific nominated pass through events should be included in the AER's determination for UED for the forthcoming regulatory control period:
  - introduction of a National Energy Customer Framework;
  - imposition of an emissions trading scheme;
  - corporate income tax assumptions;
  - vegetation management clearance;
  - bushfire mitigation;
  - climate change forecasting assumptions;
  - force majeure;
  - financial failure of a retailer;
  - retailer of last resort; and
  - introduction of the national broadband network.

19.1 Regulatory requirements and chapter structure

There is recognition in the regulatory framework that a distribution business cannot be reasonably expected to forecast costs for all foreseen and unforeseen events over the regulatory period. The Rules provide for the pass-through of costs associated with unexpected events which are beyond the control of distribution network service providers. 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.

In addition to the four stipulated events, 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. Pursuant to clause S6.1.3 (2), a building block proposal should contain a proposed pass through clause with a suggested itemisation and explanation of the events that should be defined as pass through events.

In light of the above regulatory requirements, the remainder of this chapter is structured as follows:

- Section 19.2 sets out UED's understanding of the application of pass through provisions for direct control services;
- Section 19.3 examines the nature of pass through events, and the incentives on regulated businesses to mitigate the costs that may arise from a pass through event;
- Section 19.4 examines the AER's approach to pass through arrangements in its NSW Determination;
- Section 19.5 sets out UED's comments on materiality thresholds;
- Section 19.6 sets out UED's General nominated pass through event clause;
- Section 19.7.10 sets out UED's Specific nominated pass through events clauses; and
- Section 19.8 presents comments relating to the process for assessing pass through events.

19.2 Application of pass through provisions to direct control services

The provisions for cost pass through events in chapter 6 of the Rules are subsumed into Part C, which is concerned with building block determinations for standard control services. Importantly, the provisions in Part C may also have some bearing on alternative control services. Clause 6.2.6(c) states that the control mechanism for these alternative services may (but need not) utilise elements of Part C, with or without modification.

UED's view is that the pass through provisions should apply to direct control services, which are comprised of standard control services and alternative control services.

An additional consideration in support of the argument advanced by UED is that a number of definitions in the Rules pertaining to pass throughs make reference to the impact on the costs of direct control services. The particular definitions, in chapter 10 of the Rules, are for terms such as 'negative change event', 'positive change event', 'regulatory change event', 'tax change event', 'service standard event', and 'terrorism event'. The effect on the costs of providing direct control services is identified in every case. Direct control services are comprised of both standard control services and alternative control services.

The proposed joint treatment of both types of service in respect of the applicability of pass throughs would be consistent with the revenue and pricing principles which are enunciated in section 7A of the National Electricity Law. Section 7A (2) states that:

> " A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs which the operator incurs in: -
>
> * Providing direct control network services; and
>
> * Complying with a regulatory obligation or requirement, or making a regulatory payment."

In view of the foregoing discussion, UED contends that the pass through events discussed in this chapter of the regulatory proposal are pertinent to both types of direct control service, namely standard control services and alternative control services. Specifically, pass through provisions for the defined events and nominated events should be applied to both standard control and alternative control services.

19.3 Nature of pass through events and DNSP incentives to minimise costs

The Rules establish an incentive-based regulatory framework which has the (CPI-X) form of price indexation at its core. The underlying principle of the incentive approach is that a price or revenue cap is set on a forward looking basis for a set period (usually five years).

Prices or revenues are not simply a direct function of costs incurred by the business. In general, the amounts earned by a regulated entity will depend upon the formulation embedded in the price or revenue cap, however the business can exercise control over its costs. The actual outlays by the business, driven by recurrent spending, may turn out to be more or less than the amounts assumed in the determination of the price or revenue cap.

The incentive framework functions effectively, in theory and in practice, when consideration is given to costs which are in the direct domain of the business. However, costs are sometimes imposed upon electricity distributors due to outside influences over which no control can be exerted. The imposts may vary in form and magnitude, but experience has shown that:

- The size of the impact is exogenously determined. The expenses incurred by the business in connection with the particular event are unaffected by how efficiently the entity is managed.
- The events and associated timing and costs are not readily foreseeable. The timing or size of the impost cannot be predicted in advance and, in many cases, the occurrence of the underlying event cannot be foreshadowed at all when a distribution determination is made.

The autonomous nature of the costs, when wholly external influences are at play, was recognised by the AER in its review of regulatory pricing proposals put forward by the NSW distribution network service providers. The AER deliberated on the role of pass through events, in the context of the services provided by the NSW distribution network service providers, and stated, in its draft determination[102], that:

> " An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks properly and incurs additional costs, it would be expected to bear those costs. However, the Rules recognises that DNSPs are exposed to risks beyond their control, which may have a material impact on their costs. In some cases, the risk may be symmetrical, in which case costs could potentially increase or decrease."

The unforeseeable occurrence of certain events, and the unforeseeable timing and/or cost of foreseeable events, a number of which are related to government policy, lends credence to the view that costs 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 AEMC has acknowledged that a system of pass throughs may produce better outcomes for consumers in those instances where:

- the events are ill-suited to incentive regulation; and
- a pass through offers the cheaper option, or possibly the only option.

In its Rule Determination on the Economic Regulation of Transmission Services[103], the AEMC emphasised that:

> " The objective of the cost pass-through is to provide a degree of protection for the TNSP from the impact of unexpected changes in costs outside of its control. The Commission considers that such a mechanism provides a reasonable reflection of the operation of a competitive market where efficient costs are eventually passed through to customers, whether they are expected or not. Such a mechanism lowers the risks faced by the TNSP, which would otherwise have to be compensated for in the calculation of regulated revenues."

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. Accordingly, projections cannot be prepared for incorporation in the baseline expenditure forecasts, which comprise the core part of the building block proposal. UED is also acutely aware that the application of the weighted average cost of capital (WACC) to the regulatory asset base does not provide sufficient compensation for various external forms of risk. The inability to compensate arises because the WACC parameters are generally underpinned by an assumption that electricity distribution is a relatively stable business offering a modest risk reward profile.

In other cases, insurance is an appropriate means of addressing the risk of possible cost increases resulting from unexpected events. UED has comprehensive insurance policies in

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[102] **AER (2008k4). Draft Decision. New South Wales draft distribution determination, 2009-10 to 2013-14. Australian Energy Regulator, 21 November 2008.**

[103] **AEMC (2006k1). Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, Rule Determination. Australian Energy Markets Commission, 16 November 2006.**

place, and has also sought to mitigate the potential impact of insurance deductibles by the proposed set aside of a self-insurance provision. 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.

A further noteworthy consideration is that if the AER gives approval to a pass through event, then this does not, in any way, lessen the discipline on a business to maintain efficient costs and to ensure accountability in terms of the actual increments which are then charged to consumers. Clause 6.6.1(j)(3) of the Rules provides strong incentives for a distribution business to take all reasonable measures to mitigate the impact on consumers of a 'positive change event'. Relevant excerpts from section 6.6.1(j) are as shown:

> " In making a determination [in relation to a pass through event], the AER must take into account:
>
> (3) In the case of a positive change event, the efficiency of the provider's decisions and actions in relation to the risk of the positive change event, including whether the provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event."

In view of the foregoing clause in the Rules, UED will make every effort to ensure that the costs passed on to consumers, in the wake of a pass through event, will be minimised. UED will retain its incentive to operate efficiently.

UED also 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 that may never eventuate and over which the business cannot exert control.

19.4 Final decision, NSW distribution determination, 2009-10 to 2013-14

In its final decision on the distribution determination for NSW distribution network service providers (AER, 2009d1), the AER concluded that there should be two separate categories for nominated pass through events. The classifications were:

- Specific nominated pass through events: These are foreseeable (expected) events which can be readily defined, however the timing and/or cost impact cannot be foreshadowed.
- General nominated pass through events: These are possible but unforeseeable (unexpected) events, driven by unanticipated changes in circumstances which are separate to the normal business operations of a DNSP.

19.4.1 Specific nominated pass through events

According to the AER (AER, 2009d1), a specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, even if the exact timing and/or the cost impact cannot be foreshadowed at the time that the AER makes its distribution determination. In such circumstances, the AER considers it appropriate that expenditures be included when the costs of the relevant activities are able to be forecast on a reasonable basis, and when the timing of the events is known with certainty.

An event will be regarded as foreseeable if the AER forms an expectation of a reasonable likelihood of occurrence during the next regulatory period, based on the information available to the AER when it makes its distribution determination.

The specific nominated events put forward by the NSW distributors, which were accepted by the AER, can be itemised as follows:

- a retail project event;
- smart meter event;
- an emissions trading scheme event; and
- an aviation hazards event (in the case of Country Energy).

In terms of the aforementioned events, United Energy considers that the imposition of an emissions trading scheme is of relevance to its business, and would need to be classified as a pass through event.

19.4.2 General nominated pass through events

The AER acknowledged that possible but unforeseen events could occur during a regulatory control period, with a consequent material impact on costs. The examples given of such an event included a major natural disaster such as a bush fire or earthquake, and liability for claims relating to asbestos or electric and magnetic fields. In these circumstances, although the occurrence of the event may be a possibility, the precise incidence is unforeseen because there is not a firm expectation of the event taking place during the next regulatory period.

In its deliberations on general nominated pass throughs, the AER conjectured (AER, 2009d1) as follows:

> " If an unforeseeable and uncontrollable event would have a material impact on a NSW DNSP's costs such that it would jeopardise the DNSP's ability to provide direct control services in accordance with the requirements of the NEL and the transitional chapter 6 rules, it is appropriate that the costs should be passed through to consumers. Where an event is of such an unusual and unexpected nature, and the associated costs are likely to have such an impact on the returns of the business that services would be jeopardised, it may be appropriate that the costs associated with the event should be passed through to customers immediately rather than waiting until the next regulatory control period."

The AER adopted a view that unforeseeable events cannot be readily defined. Therefore, rather than attempting to specify and prescribe the full range of unforeseeable events that could conceivably occur during a regulatory control period, the AER considered that it would be more useful to describe a general set of circumstances. If any of the circumstances arose during a regulatory period, then there would be no cause to trigger a general pass through event.

The AER stated that an event should be classified as a general pass through if it met the following criteria:

- An uncontrollable and unforeseeable occurrence that falls outside of the normal operations of the business, such that prudent, operational risk management could not have prevented or mitigated the effect of the event.
- The change in costs of providing distribution services as a result of the event is material, and is likely to significantly impair the capacity of the distributor to achieve the operating expenditure objectives, and/or the capital expenditure objectives (as defined in the transitional chapter 6 Rules) during the next regulatory control period.
- The event does not fall within any of the following definitions:
  - o 'regulatory change event' in the Rules (read as if paragraph (a) of the definition were not a part of the definition);
  - o 'service standard event' in the Rules;
  - o 'tax change event' in the Rules;
  - o 'terrorism event' in the Rules;
  - o 'retail project event' in the final decision;
  - o 'smart meter event' in the final decision;
  - o 'emissions trading scheme event' in the final decision;
  - o 'aviation hazards event' in this final decision.

The AER also added further elements to its definition, notably that:

- An event will be considered unforeseeable if, at the time the AER makes its distribution determination, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the next regulatory control period; and
- 'Material' means the costs associated with the event would exceed one per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

19.4.3 Relevant factors when designating an event as a pass through

The Regulator's draft decision for NSW distributors (AER, 2008k4), listed eight assessment criteria as factors to which the AER will have regard in determining whether an event should be nominated for pass through status. The eight qualifying criteria can be set out as follows:

- The event is already captured by the defined event definitions.
- The event is clearly identified.
- The event is uncontrollable. That is, a prudent service provider through its actions could not have reasonably prevented or substantially mitigated the event.

- Despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the DNSP at the time of submitting its regulatory proposal.
- No pre-existing insurance policies against the event are in place.
- Self-insurance against the event is infeasible because a self-insurance premium cannot be calculated, or the potential loss to the relevant DNSP is catastrophic.
- The party which is in the best position to manage the risk is bearing the risk.
- The passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

United Energy has examined the final decision by the AER in the NSW distribution determination (AER, 2009d1), and has drawn upon it for guidance when nominating pass through events.

19.5 Materiality thresholds

The cost pass through provisions should apply to imposts on, or advantages to, a distribution business caused by unanticipated, exogenously determined events. The business operations of UED are likely to be affected by a range of unforeseen events over the forthcoming regulatory control period. The incremental costs that will be incurred by UED in the course of managing these events have not been incorporated into the operating and capital expenditure forecasts because of uncertainties about timing, scope and magnitude.

In a position paper prepared in the context of the ACT and NSW distribution determinations[104], the AER posited that the requirement under the Rules was to set a threshold that would exclude pass through events which are not material. The AER did not refer to a specific clause in the Rules but noted that there is an implicit assumption in the NER that the threshold should be above zero. The Regulator also conceded that the Rules do not provide a guide as to how materiality should be assessed (AER, 2007l1). Accordingly, the AER took account of thresholds that had been set by IPART (the Independent Pricing and Regulatory Tribunal, NSW) and the ICRC (the Independent Competition and Regulatory Commission, ACT) in other decisions. The AER also examined other materiality thresholds applicable to transmission businesses and noted that:

> " A consideration in determining the appropriate threshold is to minimise the consequence of inaccurate forecasting. While the AER supports the current incentive based regulatory framework, the AER would like to ensure that it does not set the threshold too high so as to prevent DNSPs from recovering legitimate and efficient costs. The AER also notes that a low threshold may reduce the incentive the DNSP might have to effectively manage legitimate costs."

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[104] AER (2007l1). Preliminary Positions. Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014. Demand management incentive scheme. Control mechanisms for alternative control services. Approach to determining materiality for possible pass through events. Australian Energy Regulator, December 2007.

In its final decision on the NSW distribution determination for 2009-10 to 2013-14 (AER, 2009d1), the AER assessed that separate materiality thresholds should apply to general versus specific nominated pass through events.

For specific nominated events, the administrative costs of preparing and evaluating an application for pass through were deemed to be a sufficient threshold. The AER concluded that the costs associated with these events would have been included, without prior consideration of the materiality of the impact on the DNSP, had the necessary information been available at the time of the final decision. UED concurs with this view, and with the AER's judgement that the costs of assessing a cost pass through may, in certain circumstances, be low. Since specific nominated pass through events are narrowly defined, the AER deduced that a low materiality threshold would not undermine incentives to manage expenditure efficiently. UED has selected a threshold to apply to each specific nominated event.

For general nominated pass through events, the AER determined that the event would have a material impact if the associated costs surpassed one per cent of trend forecast revenues in the year in which the costs were incurred. Therefore, events would only qualify for immediate pass through to customers, via tariff changes, if the one per cent revenue hurdle were satisfied. The AER provided no empirical justification for its choice of the one per cent hurdle.

UED accepts that a materiality threshold should apply to a general nominated pass through event. However, UED disagrees with the contention that the cut-off should be based solely on annual revenue. UED believes that two aspects of the threshold calculation need to be modified. These relate to:

- the rigid application of a fixed share of revenue in determining the relevant cut-off; and
- the use of the smoothed forecast revenue (calculated in the final decision) for the year in which costs are incurred.

The disallowance of cost recovery (by virtue of the imposition of a high pass through threshold) would result in reduced earnings for UED, ultimately affecting the company's ability to deliver services in accordance with its service performance targets.

UED proposes that the materiality threshold should be one per cent of annual average revenue, or a fixed amount of $3 million, whichever is the lower.

In respect of the actual revenue measure employed, UED considers that the AER's choice of the smoothed or trend forecast revenue for the year in which costs are expensed is not a suitable approach. The impact of a pass through event is generally spread out over time, rather than being confined to a single year. The AER's approach could lead to undue emphasis on a particular year, with the potential to distort the incentives faced by distribution businesses. The expenditure profile resulting from a pass through event would become more important than the totality of the costs incurred. Alternatively, businesses could be forced to bear the burden of adverse developments if the expenditures were distributed across several years, with the amount spent in each year falling marginally below the threshold. UED maintains that regulated businesses should not have to carry losses simply because there may be scope to allocate the losses across years.

The AER's existing approach appears to be inconsistent with the revenue and pricing principles. The principles provide that a regulated network service provider will be able to recover at least efficient costs.

Consequently, UED proposes that the appropriate method is to apply the materiality test 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.

19.6 General nominated pass through events

UED nominates the following general nominated pass through event clause. The clause is based on the NSW distribution determination, adjusted for the Australian Competition Tribunal decision and UED's views regarding materiality.

A general nominated pass through event occurs in the following circumstances:

- an uncontrollable and unforeseeable occurrence, such that prudent, operational risk management could not have prevented or mitigated the effect of the event;
- the change in costs of providing distribution services as a result of the event is material;
- the event does not fall within any of the following definitions:
  - 'regulatory change event' in the Rules (read as if paragraph (a) of the definition were not a part of the definition);
  - 'service standard event' in the Rules;
  - 'tax change event' in the Rules;
  - 'terrorism event' in the Rules;
  - 'introduction of NECF event' in the final decision;
  - 'emissions trading scheme event' in the final decision;
  - 'corporate income tax event' in the final decision;
  - 'vegetation management event' in the final decision;
  - 'financial failure of a retailer event' in the final decision;
  - 'retailer of last resort event' in the final decision;
  - 'national broadband network event' in the final decision.

For the purposes of this definition:

- An event will be considered unforeseeable if, at the time of submitting the Regulatory Proposal, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the next regulatory control period; and
- 'Material' means the costs associated with the event would exceed one per cent of annual average revenue, or a fixed amount of $3 million, whichever is the lower.

19.7 Specific nominated pass through events

UED nominates the following specific nominated events as being foreseeable in terms of occurrence during the regulatory control period, although the timing and/or the cost impact cannot be foreshadowed at this time. These are:

- 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.

Each of the events is described in further detail below.

For each of these events UED proposes 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. The amount of $200,000 has been determined by reference to the administrative costs that would be incurred in the course of preparing and assessing an application for pass through. UED has estimated the administrative costs taking into consideration the administrative costs that would be incurred by the business and by the AER itself.

19.7.1 National Energy Customer Framework

National regulatory reform has the potential to give rise to new regulatory obligations with which UED must comply. The Ministerial Council on Energy (MCE) has been charged with responsibility for establishing a national framework to regulate the sale and supply of energy (both electricity and gas) to retail customers. The National Energy Customer Framework (NECF) forms part of the ongoing national energy market reforms set out in the Australian Energy Market Agreement (AEMA), which was amended in June 2006 to include the transfer of retail and distribution regulation (other than retail pricing) to a national framework. The laws and rules pertaining to retail and distribution activities will be progressively transitioned into a national framework.

The introduction of the NECF is a major regulatory reform which will have an impact on UED's operations. The existing arrangements vary between the jurisdictions because each State developed its own system in isolation to meet unique requirements which prevailed at the time of development. Although some jurisdictional obligations and requirements will be retained, the shift to the NECF may result in significant parts of the Victorian regulatory framework being removed or amended before the NECF can become operational.

The first exposure draft of the NECF was released for consultation on 30 April 2009. In its current form, the legislative package comprises:

- A new, stand-alone National Energy Retail Law ("NERL") that sets up the framework for the NECF to be applied as the law of each jurisdiction. The method of application would essentially mirror the way in which the NEL is currently applied.
- A new set of National Energy Retail Rules ("NERR"), which focus on consumer protection matters; and
- A new set of Regulations, the National Energy Retail Regulations, which would be put into effect in the context of the NERL.

In their draft form, the NERR incorporates three model contracts which will govern the relationship between customers, distributors and retailers. The NERR would be made within the framework of the NERL in a parallel fashion to the way in which the Rules are made under the auspices of the NEL.

There are a number of measures under consideration in the NECF legislative package, in respect of which consultations are currently underway. The matters which remain to be finalised include:

- the determination of a distributor's obligations with regard to the provision of connection services;
- the interface between distributors, retailers and embedded generators;
- legal architecture, service definitions, and liability and indemnity regimes;
- the entry criteria for retail licences;
- retail credit support arrangements and the AER enforcement regime; and
- the arrangements for a national Retailer of Last Resort (ROLR) scheme.

The impact of the NECF legislative package on UED's costs cannot, as yet, be quantified. The business has a reasonable understanding of the proposed contracts, service definitions, and associated liabilities, and expects that changes to current practice will need to be made. However, the costs of implementing the new systems and of conforming to the new arrangements cannot be assessed at this stage, and so UED has not included an estimate of the costs associated with the new arrangements into its expenditure forecasts for the forthcoming regulatory period.

It is unclear if the implementation of the NECF legislative package and the associated transfer of the current regulation of retail and distribution activities to a national framework would meet the designated criteria for a regulatory change event. In particular, a regulatory change event is limited to changes in a regulatory obligation or requirement and does not encompass the removal or imposition of a new regulatory obligation or requirement (consider, by way of contrast, the definition of a tax change event). Accordingly, to meet the AER's requirement that a nominated pass through event cannot already be captured by the defined event definitions, UED proposes to deal with this event in a manner which corresponds with the way in which Integral Energy dealt with the emissions trading scheme event (see below). Accordingly, the NECF event will be either a regulatory change event or a specific nominated pass through.

UED's nominated "introduction of the NECF event" is:

" An **introduction of the NECF event** is an event which results in the removal or imposition of legal obligations on United Energy arising from the introduction or operation of the national energy customer framework during the course of the regulatory control period and which:

a) falls within no other category of pass through event; and

b) increases or decreases the costs to United Energy of providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application, or a fixed amount of $200,000 whichever is the lower."

This event meets the assessment criteria set out by the AER in its final decision on the NSW distribution determination (AER 2009d1) on the grounds that:

- the event (as drafted) is not included in any other pass through category;
- there will be a shift away from the current legislative model and the contracts in place as at the lodgement date of this Regulatory Proposal;
- the manner in which a DNSP provides direct control services will be significantly altered;
- there will be material increases in the costs of providing services, at least initially;
- the event is uncontrollable in the sense that UED cannot influence the passage of the legislation;
- although the event is foreseeable, the timing and cost impact cannot be readily ascertained because consultations about the legislative package are still underway. Decisions yet to be taken by the Victorian Government will also have a bearing on the timetable for the transition; and
- the passing through of costs would not undermine the incentive arrangements.

UED is of the view that a staged approach will be taken to the introduction of the NECF package in Victoria. The company therefore reiterates its submission that the materiality threshold should be assessed in the context of the whole event, and not in terms of expenditure in a single year, whichever year that may be.

19.7.2 Introduction of an emissions trading scheme

The CPRS developed by the Commonwealth Government is essentially based on an emissions trading scheme (ETS). At present, the new system appears scheduled to take effect on 1 July 2011. The CPRS is the main policy mechanism by which Australia will meets its obligations under the Kyoto Protocol.

In its final decision on the NSW distribution determination (AER 2009d1), the AER determined that an emissions trading scheme should be classified as a specific nominated pass through event on the grounds that:

- the event is not already captured by the defined event definitions;
- the event is uncontrollable because if the event occurs, a DNSP will be legally obliged to comply with the scheme;

- although the event is foreseeable, the timing and cost impact can not be reasonably forecast, as the scope of the obligation is not known at this time;
- the event is not an insurable event; and
- passing through the costs will not undermine regulatory incentives, given that the obligation will be imposed externally.

In the draft decision the AER had held that an emissions trading scheme event would constitute a regulatory change event (AER, 2008k4). In the final decision, the AER stated that:

> " Integral Energy defined an emissions trading scheme event to exclude circumstances in which the event would be a regulatory change event. Therefore, the event is not captured by defined events."

The definition of an emissions trading scheme event provided by Integral Energy in its regulatory proposal has been reproduced below:

> " An emissions trading scheme event is an event which results in the imposition of legal obligations on Integral Energy arising from the introduction or operation of a carbon emissions trading scheme by the Commonwealth during the course of the regulatory control period and which:
>
> a) Falls within no other category of pass through event; and
>
> b) Materially increases the costs of Integral Energy providing the direct control services."[105]

UED concurs with the above definition, but would like to add that:

- An emissions trading scheme may be implemented by either the Federal or Victorian governments during the forthcoming regulatory control period.
- The effects of the scheme will not be included in any other category of pass through event.
- The development and phase-in of the scheme, during the regulatory control period, has the potential to result in material increases in the costs to UED of providing direct control services. There may also be significant changes to the manner in which those services are provided.

At the time of preparing this Regulatory Proposal, it was unclear whether the CPRS, which was brought before the Parliament on 22 October 2009, would have a major financial impact on UED. This is because amendments to the legislation were still being made.

Emissions that contribute to a carbon footprint are divided into groups, by the Department of Climate Change, in accordance with the following scheme:

- Scope one emissions are direct emissions, such as the fuel burn in a company fleet

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[105] **Integral (2008f). Regulatory Proposal to the Australian Energy Regulator, 2009 to 2014. Delivering efficient and sustainable network services. Integral Energy. 2 June 2008.**

- Scope two emissions include the electricity actually 'used' by distributors such as UED. Distribution losses fall into this group.
- Scope three is made up of indirect emissions, such as employee travel.

The CPRS which is scheduled to commence on 1 July 2011 will, in all likelihood, deal only with Scope one emissions. Accordingly, distribution losses will be borne by the electricity market, and UED will not be required to participate. However, if the threshold for Scope one emissions were reduced in future, or if Scope two and three emissions were included, then UED would be liable for significant costs because the company contributes indirectly to carbon dioxide emissions. The carbon footprint for UED has been estimated for the 2008-09 financial year, and reported under the National Greenhouse and Energy Reporting System (NGERS).

The actual costs which UED would seek to recover, if a pass through application were triggered, would be comprised of the direct and indirect costs which the business would have to bear in order to:

- fulfil the legislated requirements; and
- comply with regulatory obligations.

UED suggests that the manner in which ETS event costs are passed through the price cap formula could be structured so as to be similar to the under and over recovery mechanism which is used in the context of revenue caps. The use of the under and over recovery device would result in payments by UED for the CPRS being recouped annually in arrears, after a two-year lag. The payments would need to be appropriately adjusted by the WACC during the annual network pricing process. However, UED recognises that this will be an issue to be dealt with under clauses 6.6.1(d) and (j).

UED's nominated "emissions trading scheme event" is:

> " An **emissions trading scheme event** is an event which results in the imposition of legal obligations on United Energy arising from the introduction or operation of a carbon emissions trading scheme by the Commonwealth during the course of the regulatory control period and which:
>
> a) falls within no other category of pass through event; and
>
> b) increases or decreases the costs to United Energy of providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application, or a fixed amount of $200,000 whichever is the lower."

This event meets the criteria for assessment which were set out by the AER in its final decision on the NSW distribution determination. The AER explained its reasons for accepting the event in that decision (AER, 2009d1).

19.7.3 Changes in corporate income tax

Under chapter 10 of the Rules, a tax change event is said to occur over the course of a regulatory period if there are variations in the fiscal regime which match the descriptions provided below:

(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

in consequence, the costs to the service provider of providing prescribed transmission services or direct control services are materially increased or decreased.

An important qualifying criterion for a tax change event is that the cost impact on a distributor should be material, whether negative or positive. The term 'relevant tax' is defined in the Rules as being a tax payable by a DNSP other than:

a) income tax and capital gains tax;

b) stamp duty, financial institutions duty and bank accounts debits tax;

c) penalties, charges, fees and interest on late payments, or deficiencies in payments, relating to any tax; or

d) any tax that replaces, or is the equivalent of or is similar to any of the taxes referred to in paragraphs (a) to (b) (including any State equivalent tax).

The definition of a relevant tax therefore appears to rule out corporate income tax, and, consequently, a change in the rate of corporation tax cannot be a tax change event. However, UED's view is that an alteration in corporate tax rates should be treated as a pass through event because:

- The submission prepared by UED for the current regulatory review is premised on the existing taxation regime remaining in place. This Regulatory Proposal has not factored in a change in rates for any of the principal taxes which UED is liable to pay.
- If the Federal or State governments were to amend existing tax rates, tax thresholds, or tax instruments in any substantive way, then UED, as a regulated entity, would have limited flexibility to respond. These changes, unless pre-announced, would be beyond the control of a benchmark, efficient entity and would lie outside the remit of the current price review. A benchmark entity has been contemplated when determining the cost of corporate income tax in accordance with clause 6.5.3 of the Rules.
- In the absence of a cost pass through, there would be no compensation available to UED for changes in its liabilities resulting from an altered fiscal regime.

An example of the type of tax event which, in the absence of a pass through provision, would hinder UED's ability to meet its ongoing obligations, would be an unscheduled increase in company tax rates from, say, 30 per cent to 40 per cent. A comparable example would be an Australian Taxation Office ruling which limited the tax deductibility of expenses arising from the capitalisation of labour costs, overheads, and other internal on-costs. In both cases, UED would be forced to bear a tax burden for which it has not been funded because different assumptions about the tax environment would have been employed when modelling the prospective liabilities of the benchmark efficient entity.

The Henry tax review is a potential tax change event in relation to which UED may seek to claim a pass through. The review is expected to report by the end of calendar 2009. A discussion paper, labelled the "Architecture of Australia's tax and transfer system" was released in August 2008. At this stage, the expectation is that recommendations resulting from the review will be implemented, either in whole or in part, by May 2010. If the Government delivers to the timetable, then UED will have sufficient leeway to make revisions to its expenditure forecasts, and there will be no requirement for a pass through claim. However, UED foresees the potential for a pass through application if there are delays in the instigation of the tax reforms beyond 2010, and if the precise nature of the reform package remains unclear by mid-2010.

UED's nominated "change in corporate income tax event" is as described below:

> " A **corporate income tax event** is an event which results in changes to the corporate income tax assumptions used to estimate the costs of corporate income tax under clause 6.5.3 of the Rules during the course of the regulatory control period and which:
>
> a) falls within no other category of pass through event; and
>
> b) increases or decreases the costs to United Energy of providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application, or a fixed amount of $200,000 whichever is the lower."

This event meets the assessment criteria set out by the AER in its in its final decision on the NSW distribution determination (AER, 2009d1). In particular:

- the event (as drafted) is not included in any other pass through category;
- the event is clearly identified;
- there will be material increases in the costs of providing services;
- the event is uncontrollable in the sense that UED cannot influence the passage of the legislation;
- the event is not insured against or is capable of self-insurance;
- although the event is foreseeable, the timing and cost impact cannot be readily ascertained because the Henry tax review is still underway; and
- the passing through of costs would not undermine the incentive arrangements.

19.7.4 Proposed new requirements for vegetation management

UED currently complies with regulations governing the clearance of overhanging vegetation from aerial power lines. The existing regulations, described more formally as the Electricity Safety (Electric Line Clearance) Regulations 2005, are currently administered by Energy Safe Victoria, and are scheduled to expire on 30 June 2010, however a sunset of regulations can be extended. A Code of Practice for electric line clearance is appended to the regulations as a schedule.

A new set of regulations may take effect from 2010, and a draft of the new code is currently being considered by the Electric Line Clearance Consultative Committee. Several changes have been proposed which will result in a more intensive regime of vegetation management. The proposed changes include:

- A cessation of the current exemption from the clearance space requirements which are specified in clause 2.1 of the Code of Practice. The exemption was granted by Energy Safe Victoria and came into effect in December 2005. It was scheduled to expire when the Regulations ceased to have any effect.

- A withdrawal from the current Code of Practice of the existing clause 11.2. Currently, the effect of this clause is to allow overhanging branches and trees, which do not exhibit potentially hazardous structural defects, to come into closer contact with power lines that are not insulated (and that are not constructed using aerial bundled cable).

- The removal of clauses 9.2.1 and 9.2.2. To date, these clauses have meant that small branches and leaves can come into direct contact with aerial bundled cable and insulated cables, provided that there is no abrasion of the cable, and on the understanding that the branches and leaves are pruned at least once per annum.

- A withdrawal of clause 3(b) which is concerned with notifications provided to land owners. Electricity distributors are currently required to give written notice to the occupiers of land on which vegetation is to be pruned or cleared. The new regulations will contain an additional paragraph, labelled clause 5.3, which will impose a discipline on businesses to consult with occupiers, rather than simply issue notices.

The proposed new regulations would result in a significant increase in UED's forecast vegetation management costs. However, UED has not included the effect of the proposed changes in its expenditure forecasts in this regulatory proposal, because there is insufficient certainty at this time (regarding the timing of introduction of the proposed changes, and the final scope of the changes) to undertake robust expenditure forecasting. For this reason, UED proposes that changes to vegetation management requirements resulting from the introduction of the proposed new safety regulations should be nominated as a pass through event. That said, UED acknowledges the possibility that prior to the AER making its determination, sufficient certainty may emerge regarding the scope and timing of the proposed new regulations, in which case UED would seek to revise its operating expenditure forecasts to include a provision for the estimated additional cost of complying with the requirements.

Owing to the lack of policy clarity at present, UED believes that the introduction of the proposed new regulations should be nominated as a specific pass through event. Importantly, the imposition of an enhanced tree clearing regime and more frequent cycles of tree pruning result from new regulations. Furthermore:

- the event falls within no other category of pass through (as the event is defined);

- despite the event being foreseeable, the timing and/or cost impact cannot be reasonably anticipated as at the date of submission of this regulatory proposal;

- the event is clearly identified;

- the event is uncontrollable in the sense that UED cannot influence the passage of the legislation;

- insurance cover is not available for the event, and nor is it amenable to self-insurance;

- the event materially increases or materially decreases the costs of providing these services; and

- the passing through of costs would not undermine the incentive arrangements.

UED's nominated "vegetation management event" is:

> " A **vegetation management event** is an event which results in the change, removal or imposition of legal obligations on United Energy in relation to the management of the

clearance of overhanging vegetation from aerial power lines during the course of 2010 or the regulatory control period and which:

a) falls within no other category of pass through event; and

b) increases or decreases the costs to United Energy of providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application, or a fixed amount of $200,000 whichever is the lower."

19.7.5 Changes to the Bushfire Mitigation Framework

UED currently complies with a set of legislation, regulations, guidelines, policies, procedures, and practices which govern the management of electricity assets in respect of bushfire mitigation – the bushfire mitigation framework.

The existing set of legislation regulations, guidelines, policies, procedures, and practices which govern the management of electricity assets in respect of bushfire mitigation were established by the Victorian electricity industry (specifically the SECV) following the Ash Wednesday bushfires in 1983.

In the time since their development this bushfire mitigation framework has been considered best practice, consistent with South-Eastern Australian being considered to be one of the most wild-fire prone region in the world, and the Ash Wednesday fires being one of the most significant wild-fire events in the world. Given the significant impact of bushfires, this framework has also has been a significant focus, and a significant driver of cost, for the Victorian distribution businesses since 1983.

The bushfire mitigation framework is overseen by the Energy Safe Victoria.

In January and February 2009 widespread bushfires in Victoria lead to 173 fatalities and significant property damage. Electricity assets are alleged to have started a number of the bushfires that occurred in that period.

On 16 February 2009 the Victorian Government established a Royal Commission to look into the bushfires. That Royal Commission is still conducting hearings.

There is a high likelihood consideration of the appropriate bushfire mitigation framework for Victorian electricity distribution businesses will lead to changes to that framework which will in turn lead to increased cost to UED. There is no way to predict any such cost impacts at this time. Such cost impacts could come about from changes to any of the legislation, regulations, guidelines, policies, procedures, and practices which form the bushfire mitigation framework.

UED's nominated "bushfire mitigation event" is:

" A **bushfire mitigation event** is an event which results in the change to the legislation, regulations, guidelines, policies, procedures, and practices which govern the management of electricity assets in respect of bushfire mitigation during the regulatory control period and which:

a) to the extent that it falls within no other category of pass through event; and

b) increases or decreases the costs to United Energy of providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application, or a fixed amount of $200,000 whichever is the lower."

19.7.6 Climate change assumptions

In recent times there significant analysis and debate around the impacts of climate change at both a global and local level. That debate and analysis has highlighted that there is currently a very high level of uncertainty and unpredictability about the impacts of climate change. That uncertainty and unpredictability can be considered at two levels:

- The very significant debate in the scientific and general community around interpretation of climate changes science – which at the simplest level leads some to claim there is no climate change (although this group is getting smaller), some to claim that the impacts of climate change will reach catastrophic levels in a short time, and some who are in the middle.
- Even if we were to understand and agree all there is to agree on in respect of climate change, there is still a recognised randomness and uncertainty about the weather conditions and events that will be experienced at a particular location over a nominated period of time (e.g. the regulatory control period). It is generally accepted that the climate change that we are currently experiencing is not only leading to higher temperatures, but also leading to greater weather variability and leading to more extreme weather events, at a level we have not seen previously.

UED is required to prepare forecasts of operating and capital expenditure for the period to December 2015 as a part of this Regulatory Proposal – i.e. forecasting 6 years hence. If we were to take ourselves back 6 years (to 2003) and consider our views on the climate/weather that we should be considering for the period to 2009, it expect that all accept that peoples views on climate change and weather events have changed significantly since 2003 and outturn climate and weather have been very different to what would have been predicted then.

In effect the world has been on a journey of understanding and discovery in respect of weather and climate over recent years. Most would agree that we are still in the early stages of that journey of discovery.

UED has engaged AECOM and the CSIRO's Marine and Atmospheric Research to assess the impact of climate change on the UED network. AECOM and CSIRO have provided predictions as to the impacts of climate change on the UED network, and these predictions have been utilised in the forecasts that underpin the Regulatory Proposal. However AECOM and CSIRO are clear in their views that such a process of prediction is problematic, with there being a wide band of uncertainty and a recognition of the situation that we are, in effect, in the early days on that journey of developing understanding in respect of the impacts of climate change.

The impacts of climate change represent a significant cost risk to UED over the coming regulatory period, and the risk is asymmetric, with the potential cost overruns associated with an underestimation of the impact, greatly exceeding the potential for cost savings associated with overestimation. It is noted that the potential for cost overruns is open ended, with the potential savings from overestimation being limited to the size of the estimate included in the forecasts.

Examples of potential cost overruns include costs associated with:

- Supply restoration and repair to damaged network assets associated with storms of greater intensity and frequency than anticipated;

- Introducing and/or increasing standby arrangements for crews, contractors, and plant, where there is an expectation or requirement for greater readiness to deal with events of greater magnitude then have currently been planned for;
- Building the network for a greater maximum demand than predicted as higher temperatures drive higher levels on installation and utilisation of air conditioning;
- Enhancing the network to compensate for de-rating of plan that can occur as ambient temperatures rise above previously expected levels;
- Building or contracting greater call centre capability or call centre escalation capability, or enhancing other communications processes/systems to meet increased community expectations (or regulatory guidelines) in respect of communications in significant weather events; and/or
- Responding to regulatory change or expectations from government or regulators in respect of any of a number aspects of managing weather events.

UED seeks a pass through event associated with any additional costs that have arisen because any of the assumptions that have been reasonably adopted in the development of the forecasts in this Regulatory Proposal has been materially underestimated, in the view of the AER.

It is recognised that that the reference point and impact of this pass through event may involve some measurement difficulties. This highlights the problems of forecasting the impacts of climate change. UED recognises this difficulty, however, UED considers that such a difficulty is not a reason for the AER to reject this very significant issue as a pass through event. In drafting the pass through event UED has attempted to deal with this difficulty by ensuring:

- the pass through applies only to ***material*** changes in assumption (which gives rise to a material change in cost) – i.e. a threshold materiality test to apply to the change in the relevant assumption, before materiality of the cost impact is even considered; and
- The AER is given the discretion to decide what is a material change in assumption.

UED's nominated "climate change assumption event" is:

" A **climate change assumption event** is an event when the climate change assumptions that underpin the EDPR forecast are found to be materially in error, where:

a) UED can demonstrate to the satisfaction of the AER that any key climate or climate change assumptions that underpinned UED's forecasts in the Regulatory Proposal have proven to be materially in incorrect, in the outturn;

b) the relevant assumptions used in the EDPR forecast were not unreasonable at the time of preparation of those forecasts; and

c) there has been a material increase in cost that was not allowed for in the Regulatory Proposal associated with the change in assumption; and

d) the cost increases nominated fall within no other category of pass through event.

19.7.7 Force majeure

The types of extreme and unpredictable event which UED would categorise as ***force majeure*** include earthquakes, fires, floods, storms, very high wind events, other major weather disturbances, natural disasters, pandemics or plagues, acts of nature, civil disturbances, riots, and rebellions. The list is not meant to be exhaustive or all-encompassing, however UED believes that any of the above types of force majeure incident could occur and affect the costs associated with the delivery of network services.

UED is insured for the liability claims which could arise in the event of a major bush fire. However, the limit of liability under the policy is $635 million. The policy cap was determined subsequent to a maximum foreseeable loss (MFL) study undertaken by Marsh Risk Consulting (Marsh, 2008). Marsh recommended a policy cap of $600 million for 2008-09, but remained alert to the possibility that losses due to a bush fire in the Mornington Peninsula could potentially breach the cap. Marsh noted that a bush fire on the Peninsula could spread to other regions beyond the area served by UED. However, the consultants nonetheless expressed the view that aggregate losses due to property damage, business interruption and loss of human life would be unlikely to surpass the assessed threshold of $600 million.

UED has been advised by its brokers, Marsh Finpro, that insurance coverage above $635 million has become difficult, if not impossible, to obtain in the aftermath of the major bush fires in February 2009. Although the likelihood of losses in excess of the policy limit is somewhat remote, UED believes that a prudent DNSP would, in these circumstances, invoke the pass through mechanism to provide coverage against losses which breached the cap. Hence, UED is requesting a pass through provision for force majeure events, including fires.

UED has proposed to self-insure against losses up the value of the deductible on its liability policy. Self insurance is discussed in section 5.5.12. The policy deductible for bush fire related claims is $5 million.

A force majeure event could conceivably occur during the next regulatory period, and is in that sense foreseeable. There is a reasonable likelihood of occurrence, although the timing and cost impact cannot be foreshadowed. UED believes that the AER should give its imprimatur to the categorisation of force majeure as a specific nominated pass through event on the grounds that:

- UED is unable to exercise control over force majeure or major storms;
- force majeure or major storm is an extraordinary event which has such an impact that it disturbs the basis of the 'regulatory bargain' implicit in a revenue determination;
- it is not included in another category of pass through event;
- it is not covered under UED's self-insurance allowance; and
- it results in material increases in the costs incurred by UED in providing direct control services.

UED is also cognisant of the position taken by the Ministerial Council on Energy in respect of the re-opening of a regulatory determination. In a paper affixed to Bulletin number 77, describing electricity and Rule change amendments, the Standing Committee of Officials (SCO) adopted the following policy stance in respect of the overall regulatory framework:

> " The initial distribution Rules will allow the AER to revoke and substitute a regulatory determination on certain grounds including where the regulatory decision was made on the basis of false or materially misleading information provided to the AER and where there was a material error made in setting the regulatory cap.
>
> There will be no re-opening for force majeure or major storms unless it is defined as a pass through event in a regulatory determination."[106]

UED notes that the recommendations of the SCO were incorporated, in part, into the Rules. Clause 6.13 of the Rules explains the limited circumstances in which a distribution determination may be revoked or substituted for another. In essence, the grounds are limited to material error or deficiency.

19.7.8 Financial failure of a retailer

Under the existing default use of system agreements in Victoria, distributors are obliged to contract with a retailer provided that the latter meets a minimum requirement in terms of creditworthiness. The minimum baseline requirement was specified in the final decision of the last Victorian electricity distribution price review (page 488, ESCV, 2005a). The standard was either an investment grade rating, or a guarantee, affirmed by a bank or parent company, to provide distribution charges covering a three month period.

Subsequent to the final distribution decision, the ESCV undertook a review of credit support arrangements, releasing a final report in October 2006[107]. The ESCV noted that credit support arrangements aim to protect customers by ensuring that distributors can secure a level of financial security against the non-payment of distribution service charges by a retailer. The arrangements contribute to the ongoing financial viability of distributors, and help to ensure that distribution network services are provided to a standard which meets customer expectations.

The ESCV (2006j) determined that a retailer is required to provide credit support to a distributor when the former party's liability for average billed and unbilled distribution service charges exceeds an assessed credit allowance. The ESCV held that the value of credit support provided by the retailer should depend upon the gap between the credit allowance and the value of the retailer's liability thus defined. The credit allowance available to a retailer is calculated as a percentage of the "maximum credit allowance" provided by the relevant distributor, and the percentage, in turn, is a function of the retailer's credit rating. The ratings are those provided by agencies such as Standard & Poor's.

The upshot of these arrangements is that UED can request credit support from a retailer in circumstances where the retailer's financial viability has been undermined by declining profitability or deteriorating liquidity. However, it is precisely in these situations that a retailer would be likely to be placed on a negative ratings watch, and would be susceptible to the possibility of a credit rating downgrade. Accordingly, the prospects of a retailer obtaining a bank guarantee would be somewhat diminished, and the distributor would be

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[106] **MCE (2007a1). Standing Committee of Officials of the Ministerial Council on Energy. Electricity amendments and further amendments to the electricity and gas rule-change process, January 2007. An explanatory document released with Energy Market Reform Bulletin No. 77.**

[107] **ESCV (2006j). Credit Support Arrangements, Final Decision. Essential Services Commission, Victoria. October 2006.**

exposed to the risk of non-payment. A retailer which failed to meet its obligations in terms of distribution service charges would, in all probability, be subject to licence revocation, however the default would, in the first instance, trigger a lengthy regulatory process. UED would seek restitution via a pass through application.

UED proposes that financial failure of a retailer should be nominated as a specific pass through event. Although the details would be a matter for determination under clauses 6.6.1(d) and (j), UED anticipates that the pass through would apply to the difference between the financial losses experienced by UED and the value of compensation able to be provided by the retailer's credit support arrangements.

UED envisages that the losses which it would experience in the event of financial failure by a retailer will be comprised of the following three components:

- recovery of bad debt and other amounts owed prior to the default;
- the expenses incurred in arranging the transfer of customers over to new retailers; and
- other administrative costs arising out of exposure to the event. These would include the expenses incurred in obtaining actual or estimated meter readings, and the amounts spent to manage the event in accordance with processes that have been agreed between industry participants and the Australian Energy Market Operator (AEMO).

UED submits that the financial failure of a retailer qualifies for categorisation as a specific nominated pass through event on the basis that:

- The event is both clearly identified and uncontrollable. A prudent service provider cannot, through its actions, reasonably prevent or substantially mitigate the event.
- Despite the event being foreseeable, the timing and/or cost impact of the event cannot be readily forecast by the DNSP at the time of submitting its regulatory proposal.
- No pre-existing insurance policies against the event are in place.
- Self-insurance against the event is infeasible because the potential loss to UED, if a large retailer were to fail, is catastrophic.
- The passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

UED acknowledges that in the event of financial failure of a retailer, the AER will review the circumstances which resulted in the loss incurred by UED, and will also take into consideration the steps taken by the distributor to mitigate financial losses.

During the Electricity Distribution Price Review for 2006 to 2010, the Victorian distribution businesses held discussions with the ESCV about retailer financial failure, as a result of which the distributors won approbation for their proposed pass through provision. A description of the pass throughs approved at the last price review is provided in ESCV (2005a), from page 487. The clause presented below is based on the definition of "financial failure of a retailer event" in that ESCV determination.

UED's nominated "financial failure of a retailer event" is:

> " A **financial failure of a retailer event** is an event whereby a retailer is placed in administration or liquidation, and as a consequence of which UED does not receive revenue of not less than $200,000. UED would otherwise have been entitled to this

revenue for the provision of direct control services during the regulatory control period. Financial failure of a retailer falls within no other category of pass through event."

19.7.9 Retailer of last resort

If an electricity retailer is unable to fulfil its financial obligations and becomes insolvent, then a financial failure event will be triggered. The financial failure will, in some circumstances, also activate a retailer of last resort (ROLR) event which means that certain procedures are invoked to transfer customers of the failed retailer to the retailer of last resort. If UED is required to take on the role of retailer of last resort, then the company will face a significant administrative burden in the short term because of a need to reconfigure and process details for a significant number of customers within a narrow time frame. The costs of such an event are not included in UED's building block proposal, and should therefore be passed through the price control mechanism.

Accordingly, UED submits that a ROLR event should be a specific nominated pass through event on the basis that:

- The event is both clearly identified and uncontrollable. A prudent service provider cannot, through its actions, reasonably prevent or substantially mitigate the event.
- Despite the event being foreseeable, the timing and/or cost impact of the event cannot be readily forecast by the DNSP at the time of submitting its regulatory proposal.
- No pre-existing insurance policies against the event are in place.
- Self-insurance against the event is infeasible, because of insufficient knowledge about the consequences of a loss, and the absence of a loss history.
- The passing through of the costs associated with the event would not undermine the incentive arrangements within the regulatory regime.

A materiality threshold has been notionally set for a ROLR event, in section 19.7. However, UED believes that a materiality test would in fact be inappropriate because the threshold would presumably already have been applied by the AER in the course of its deliberations over whether or not to declare a retailer financial failure event. Invariably, retailer financial failure will presage a ROLR event. If the financial collapse is on a scale sufficient to trigger a financial failure event, then there should be no need for further consideration of the materiality threshold. Instead, attention should be focussed on whether or not the specific criteria for a ROLR situation have been satisfied.

The retailer of last resort scenario was deemed to be a qualifying event for a pass through provision during the EDPR for the 2006 to 2010 regulatory period. The ESCV agreed to accord pass through status to future ROLR events if these were found to be material, and if there was no other mechanism available for recovering the costs (page 488, ESCV, 2005a). The clause presented below is based on the definition of "financial failure of a retailer event" in that ESCV Determination.

UED's nominated "retailer of last resort event" is:

" A **retailer of last resort event** is an event whereby an existing retailer for end use customers is unable to continue to supply electricity and those end use customers are transferred to the declared retailer of last resort retailer, and which:

a) falls within no other category of pass through event; and

b) increases or decreases the costs to United Energy of providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application or a fixed amount of $200,000 whichever is the lower."

19.7.10 National broadband network event

In April 2009, the Federal Government announced plans to build a national broadband network (NBN) at a cost of $43 billion to be spread out over eight years. An implementation study is being undertaken, with a view to determining the company's operating arrangements, the detailed network design and the ways in which private sector investment might be attracted. The Government has since invited and has also received submissions in respect of the legislative framework for the company which will be established to construct and then operate the network.

An early proposal has been to mandate the installation of fibre optic infrastructure in Greenfield residential estates which receive planning approval after 1 July 2010. There are two ways in which this objective can be achieved:

- The Federal Government could legislate directly to ensure that developers add basic pit, pipe and fibre-to-the-premises (FTTP) infrastructure in new, residential and commercial sub-divisions. There would be a requirement to make these services available to consumers from July 2010.
- Alternatively, the Government could introduce laws aimed at proscribing the installation of non-fibre networks in Greenfield estates. The Commonwealth could then engage with state, territory and local governments so as to facilitate the establishment of FTTP networks.

The Federal Government is currently involved in stakeholder discussions about a preferred model. UED is concerned that local governments and developers may attempt to shift the costs of complying with their obligations on to energy networks. If the responsibility for building core, common infrastructure components is transferred to electricity distributors, then UED will, unwittingly, be required to spend more on new connections, network augmentations and network enhancements. In these circumstances, expenditure will increase to levels in excess of the expenditure forecasts set out in the building block proposal.

UED considers that the NBN event should qualify as a specific nominated pass through because it satisfies the criteria which have been mentioned in previous examples:

- the event (as drafted) is not already captured by the defined event definitions;
- the event is uncontrollable because, if it occurs, UED will be legally obliged to comply;
- although the event is foreseeable, the timing and cost impact cannot be foreshadowed, and so the scope of the obligation is unclear at this juncture;
- the event is not modelled in insurance markets and so insurance cover cannot be procured;
- the passing through of the costs associated with the event would not undermine regulatory incentives, because the obligation will be imposed externally.

UED's nominated "national broadband network event" is:

" A **national broadband network event** is an event which results in the change or imposition of legal obligations arising from the introduction or operation of a national broadband network during the course of the next regulatory control period, and which:

a) falls within no other category of pass through event; and

b) increases or decreases the costs of United Energy in providing the direct control services in the regulatory period by not less than the administrative costs of assessing the pass through application or a fixed amount of $200,000 whichever is the lower."

19.8 Process for assessing pass through events

Section 19.1 of this Regulatory Proposal discusses the Rules' requirements for cost pass throughs, drawing, *inter alia*, on the provisions set out in clause 6.6.1 of the NER.

Importantly, clause 6.6.1(j) expounds on the relevant factors which the AER must take into consideration when determining an appropriate positive or negative pass through amount.

However, there are lacunae in the Rules with respect to details such as:

- the exact way in which the DNSP should determine the "eligible pass through amount" for the purpose of preparing its cost pass-through application;
- the Regulator's information requirements for assessing a cost pass through application;
- the practicalities of applying clause 6.6.1 of the Rules for the purpose of assessing a distributor's cost pass through application; and
- the level of explanation which the AER will provide in relation to its decision. In particular, distributors need a break up of the pass through amount into building block components, so as to ensure carriage of the pass through into their prices.

UED believes that there would be merit in the AER preparing a guideline which addresses these issues. A guideline would assist greatly in promoting the principles of best practice regulation, as promulgated by the Utility Regulators Forum[108]. UED believes that the AER should consider the following fundamental tenets when dealing with cost pass throughs:

- Parity: The AER should seek to ensure that a consistent approach is applied to the assessment of cost pass through events. This will help to promote confidence in the regulatory regime amongst distributors, customers and other stakeholders.
- Predictability: The Regulator's approach to the assessment of cost pass through applications should be predictable for distributors, customers and other stakeholders. Predictability enables a distribution business to plan confidently for the future, and to remain assured that its investments will not be undermined or exposed to undue risk as a result of the unreasonable exercise of regulatory discretion.

[108] **URF, 1999. Best practice Utility Regulation: A discussion paper. Utility Regulators Forum. July 1999.**

- Transparency: The AER should be transparent about its objectives, and up-front about its information requirements from distributors, and about the assessment processes which are to be employed. Clarity about final decisions is also required.
- Efficiency: If both parties have a fulsome understanding of the process, then they will be better placed to consider appropriate cost pass through applications. Confidence in the regulatory regime will be enhanced, and the efficiency objectives of the NEL (as detailed in section 7) are more likely to be met.

20. Negotiating framework

Key messages

- UED's negotiating framework will apply to negotiated distribution services, in accordance with UED's proposed classification discussed in section 12.
- UED's negotiating framework is consistent with the requirements of clause 6.7.5(c) of the Rules.

20.1 Regulatory requirements and chapter structure

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.

As discussed in section 12, UED proposes to accept the AER's proposal that the following services be classified as negotiated distribution services:

- alteration and relocation of UED public lighting assets;
- new public lighting.

Clause 6.1.3 of the Rules provides that the terms and conditions of access are, in relation to negotiated distribution services, the price of those services (including, if relevant, access charges) and other terms and conditions for the provision of those services.

Clause 6.7.5(b) of the Rules requires that UED's negotiating framework must comply with and be consistent with the applicable requirements of the relevant distribution determination and clause 6.7.5(c).

UED's negotiating framework, which is attached as an appendix, is submitted for the approval of the AER under clause 6.12.1(15) of the Rules.

The remainder of this chapter provides an overview of UED's negotiating framework and describes how the negotiating framework complies with and is consistent with clause 6.7.5(c) of the Rules.

20.2 Outline of Negotiating Framework

UED's negotiating framework has been prepared:

- having regard to the requirements of clause 6.7 of the Rules in relation to negotiated distribution services; and
- having regard to UED's existing processes for negotiating the provision of customer connection and augmentation works.

A summary of the negotiating framework is provided below.

- *Section 1 (Preamble) and Section 2 (Application of Negotiating Framework)*: These sections are introductory in nature and provide a general description of the Rules requirements and application of the negotiating framework.

- *Section 3(Commencement of negotiations)*: This section provides that a Service Applicant who wishes to receive a negotiated distribution service must first submit a written request to UED (Offer Request). As part of that request the Service Applicant may also request a preliminary non-binding estimate of the price of the negotiated distribution service.

  This section is consistent with UED's current practices.

- *Section 4 (Provision of Commercial Information by Service Applicant) and Section 5 (Provision of Commercial Information by United Energy)*: These sections provide for requests for further commercial information by either UED or the Service Applicant and for the application of confidentiality requirements to the provision of that information.

- *Section 6 (Process and Time frame for agreeing provision of negotiated distribution services)*: This section sets out the substantive procedures to be followed during negotiations between UED and the Service Applicant. It requires that:

  - UED make an offer to the Service Applicant to provide the negotiated distribution service within 20 Business Days of receipt of an Offer Request. The offer must contain the price and terms and conditions for provision of the service. In preparing the offer UED must comply with schedule 2 to the negotiated framework (Pricing Principles).

  - the Services Applicant may accept the offer made by the Service Applicant within 60 days.

  - These procedures described above are consistent with UED's current practices, and UED's distribution licence.

  - if the Service Applicant rejects UED's offer, at the option of the Service Applicant, UED and the Service Applicant must agree a programme for further negotiations. The parties have a further 60 Business Days to agree this programme and complete their negotiations.

- *Section 7 (Obligation to negotiate in good faith)*: This section requires that UED and the Service Applicant negotiate in good faith.

- *Section 8 (Determination of impact on other distribution network users and consultation with affected distribution network users)*: This section requires that UED consider the impact of the provision of the negotiated distribution service on other distribution network users and consult with affected users.

- *Section 9 (Suspension of Timeframe for Provision of a negotiated distribution service)*: This section provides that the timeframes for negotiation may be suspended in certain circumstances.

- *Section 10 (Dispute Resolution)*: This section provides that disputes between UED and the Service Applicant are to be dealt with in accordance with UED's internal dispute resolution processes in the first instance and, failing resolution, the Rules dispute resolution processes.

- *Section 11 (Payment of UED's reasonable costs)*: This section provides that UED may recover from the Service Applicant its reasonable direct costs incurred in processing an application.
- *Section 12 (Termination of Negotiations)*: This section sets out the circumstances in which a party may terminate negotiations. The Service Applicant may terminate negotiations at any time.
- *Section 13 (Publication of Results of negotiations on website), Section 14 (Giving notices) and Section 15 (Miscellaneous)*: These sections contain various administrative provisions in relation to negotiations and the negotiating framework.
- *Section 16 (Definitions and interpretation)*: This section defines terms used in the negotiating framework.
- *Schedule 1 (Negotiated Distribution Services)*: This schedule contains a description of the negotiated distribution services provided by UED.
- *Schedule 2 (Pricing Principles)*: This section sets out the pricing principles with which UED will comply in preparing an offer to provide a negotiated distribution service.

  These pricing principles are consistent with the negotiated distribution service principles set out in clause 6.7.1 of the Rules.

20.3 Compliance with requirements of Rules clause 6.7.5(c)

In compliance with the requirements of clause 6.7.5(c) of the Rules, UED's negotiating framework:

- requires UED and the Service Applicant to negotiate in good faith – see section 7;
- requires UED to provide commercial information to the Service Applicant – see section 5;
- requires UED to provide to the Service Applicant information regarding the costs of providing the negotiated service and the relationship between those costs and the charges offered by UED and to have in place arrangements for assessment and review of those charges – see section 6(b);
- requires the Service Applicant to provide commercial information to UED – see section 4;
- requires that negotiations to be commenced and finalised within specified periods and that UED and the Service Applicant make reasonable endeavours to comply with these time limits – see section 6(d) and 6(e);
- contains a process for dispute resolution in accordance with the relevant provisions of the NEL and the Rules – see section 10;
- contains arrangements for payment of UED's reasonable direct expenses incurred in processing an application – see section 11;

- requires UED to consider the impact of the provision of the negotiated distribution service on other distribution network users and consult with affected users – see section 8;
- requires UED to publish the result of negotiations on its website - see section 13.

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
A-4	Regulatory Information Notice – Proforma Statements – per Framework and Approach Complete	Commercial in Confidence
A-5	Regulatory Information Notice – Compliance Requirements	Public
A-5.01	RIN Reinforcement	Public
A-5.02	RIN Load Movement	Public
A-5.03	RIN Reliability Maintained	Public
A-5.04	RIN Environment and Safety	Public
A-5.05	RIN IT	Public
A-6	Board Resolution to Self Insure	Public
A-7	NER Checklist	Public
B-1	Post Tax Revenue Model	Public
B-2	Roll Forward Model	Public
B-3	Efficiency Carryover Calculations	Public
B-4	Public lighting model	Public
B-5	Network Capital Expenditure Work Plan	Commercial in Confidence
B-6	Calculation of the reference lines	Public
B-7	Increased operating and maintenance costs	Public
C-1	Forecasting Methodology	Commercial in Confidence
C-2	Alternative Control Services	Commercial in Confidence
C-3	Cost Allocation Methodology	Public
C-4	Negotiating Framework	Public
D-1	BIS Shrapnel –Wages Outlook for the Electricity Distribution Sector, August 2009	Public
D-2	SKM - Victorian Distribution Network Service Providers annual material cost escalators 2010 - 2015	Public
D-3	NIEIR Energy Report	Public
D-4	NIEIR – Maximum Demand	Public
D-5	Review of Network AMP	

Ref	Title	Status
E-1	Network Asset Management Plan	Public
E-1.01	Automatic Circuit Reclosers Life Cycle Management Plan	Commercial in Confidence
E-1.02	Bushfire Mitigation Life Cycle Management Strategy	Commercial in Confidence
E-1.03	Communications Network & Equipment Life Cycle Management Plan	Commercial in Confidence
E-1.04	Connector & Conductor Life Cycle Management Plan	Commercial in Confidence
E-1.05	Customer Meters, Time Switches and Metering Transformers Maintenance & Replacement Strategy	Commercial in Confidence
E-1.06	Distribution Transformer Life Cycle Management Plan	Commercial in Confidence
E-1.07	Earthing Systems Life Cycle Management Plan	Commercial in Confidence
E-1.08	Grounds and Housing of Zone Substations & Non-Pole Type Distribution Substations Life Cycle Management Plan	Commercial in Confidence
E-1.09	Line Capacitor Banks Life Cycle Management Plan	Commercial in Confidence
E-1.10	LV Overhead Services Lifecycle Management Plan	Commercial in Confidence
E-1.11	Non Pole Distribution Substations Life Cycle Management Plan	Commercial in Confidence
E-1.12	Outdoor Fuse Lifecycle Management Plan	Commercial in Confidence
E-1.13	Overhead Line Switchgear Life Cycle Management Plan	Commercial in Confidence
E-1.14	Pole Top Structures Life Cycle Management Plan	Commercial in Confidence
E-1.15	Poles Life Cycle Management Plan	Commercial in Confidence
E-1.16	Public Lighting Life Cycle Management Plan	Commercial in Confidence
E-1.17	Strategy for Low Voltage Private Overhead Electric Lines	Commercial in Confidence
E-1.18	Surge Arresters Life Cycle Management Plan	Commercial in Confidence
E-1.19	Underground Cables Systems Life Cycle Management Plan	Commercial in Confidence
E-1.20	Vegetation Management Life Cycle Management Strategy	Commercial in Confidence
E-1.21	Zone Substation Capacitor Banks Life Cycle Management Plan	Commercial in Confidence
E-1.22	Zone Substation Circuit Breakers Life Cycle Management Plan	Commercial in Confidence
E-1.23	Zone Substation DC Supply System Equipment Life Cycle Management Plan	Commercial in Confidence
E-1.24	Zone Substation Disconnectors & Buses Life Cycle Management Plan	Commercial in Confidence
E-1.25	Zone Substation Instrument Transformers Life Cycle Management Plan	Commercial in Confidence
E-1.26	Zone Substation Protection & Control Equipment Life Cycle Management Plan	Commercial in Confidence
E-1.27	Zone Substation Transformers Life Cycle Management Plan	Commercial in Confidence

Ref	Title	Status
E-1.28	Zone Substation/End of Feeder Power Quality Monitoring Equipment Life Cycle Management Plan	Commercial in Confidence
E-1.29	UED Planning Guidelines	Commercial in Confidence
E-1.30	Draft Distribution System Planning Report, 2009	Commercial in Confidence
E-1.31	Gating Process	Commercial in Confidence
E-2	IT Asset Management Plan	Commercial in Confidence
E-3	Assessment of Climate Change Impacts on United Energy Distribution Network for 2011-2015 EDPR	Public
E-4	Network Planning Methodology Review	Commercial in Confidence
E-5	AECOM Microgeneration	Public
F-1	Cover letter	Commercial in Confidence
F-2	Operational and Management Services Agreement	Commercial in Confidence
F-3	Project 7/11 Board paper – April 2009	Commercial in Confidence
F-4	Advice on the UED Business Model	Commercial in Confidence
F-5	Tender recommendation	Commercial in Confidence
F-6	Probity document	Commercial in Confidence
G-1	Financial Investor Group, Supplementary submission to the ERA regarding its Draft Decision on Western Power's proposed revision to the Access Arrangement for the South West Interconnected Network, Revised Final Version, 22 October 2009	Public
G-2	Dr, Bishop, W., and Professor R.R. Officer (Value Advisor Associates), Market Risk Premium, Estimate for 2011 – 2015 , October 2009	Public
G-3	AER draft determination on the 2009-2011 AMI budget and charges application, Joint submission by the Victorian DNSPs on the debt risk premium, 11 September 2009	Public
G-4	Estimating the cost of 10year BBB+ debt during the period 17 November to 5 December 2008, CEG, September 2009,	Public
G-5	PricewaterhouseCoopers, Methodology to Estimate the Debt Risk Premium, October 2009	Public
G-6	CEG, Debt and equity raising costs, A report for ETSA, June 2009	Public
G-7	Skeels,C.L., A review of the SFG Dividend Drop-off Study, 28 August 2009	Public
H-1	Closing out the ESCV S-Factor Scheme	Public
H-2	Field (2009a). Distribution of SAIDI data. A report prepared for United Energy by John Field Consulting Pty Ltd. Revised version, 26 October 2009	Public

Ref	Title	Status
H-3	Field (2009b). Distribution of SAIDI data, Part II. A report prepared for United Energy by John Field Consulting Pty Ltd. Revised version 26 October 2009.	Public
H-4	The approach proposed by UED for the application of the STPIS	Public
H-5	Efficiency Carry Over Mechanism and the Efficiency Benefit Sharing Scheme; relationship to partial factor productivity measures	Public
I-1	AON (2009). United energy Self-Insurance Quantification Report, 2009. Prepared by Aon Risk Services Australia Limited, November 2009	Commercial in Confidence
I-2	Monarc (2009j). Environmental Risk and Liability Estimates: 8-14 Railway Parade, Dandenong. Prepared by Monarc Environmental Pty Ltd, October 2009	Commercial in Confidence
I-3	Trowbridge Deloitte (2005). Commercial-in-confidence advice on potential asbestos liabilities. An actuarial assessment prepared by Trowbridge Deloitte, 22 February 2005	Commercial in Confidence
I-4	Jemena Asset Management (2008c). United Energy Distribution and Multinet Gas Environmental Provision, 2008. Prepared by Ian Russom, Technical Compliance Manager, 20 March 2008.	Commercial in Confidence
I-5	JWS (20061). Draft memorandum (68053) to United Energy regarding the available legal options for dealing with contaminated land at 8-14 Railway Parade, Dandenong. Prepared by Johnson Winter & Slattery Lawyers, 15 December 2006.	Commercial in Confidence
I-6	Marsh (2008). Bushfire Liability Study. Alinta LGA Ltd. Alinta/United Energy Distribution Network, Mornington Peninsula. Prepared by Marsh Pty Ltd, 11 September 2008.	Commercial in Confidence
I-7	UEDH Liability Renewal Report	Commercial in Confidence
J-1	Other entities	Commercial in Confidence
J-2	OSA	Commercial in Confidence
J-3	FSA	Commercial in Confidence
J-4	MSA	Commercial in Confidence
J-5	Shareholders' letter	Commercial in Confidence
K-1	Confidential letter for 20 day measurement period	Commercial in Confidence
L-1	Langwarrin Business Case	Commercial in Confidence
L-2	Langwarrin Additional information	Commercial in Confidence
L-3	Caulfield Zone Substation Business Case	Commercial in Confidence

Ref	Title	Status
L-4	Carrum Zone Substation Business Case	Commercial in Confidence
L-5	Mornington Zone Substation Business Case	Commercial in Confidence