Annual Regulatory Information Notice 2014

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Annual Regulatory Information Notice 2014

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Appendices

1. Introduction

United Energy is required to respond to the Annual Regulatory Information Notice (RIN), issued on 6 August 2014 under Division 4 of Part 3 of the *National Electricity Law* (NEL).

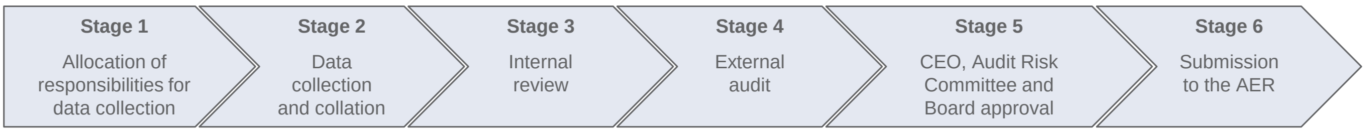
The Notice requires United Energy to provide, prepare and maintain the information in the manner and form specified in the Notice issued on 6 August 2014. The AER requires the information for the performance or exercise of a function or power conferred on it under the NEL or the *National Electricity Rules* (NER).

The Excel templates in which the information is provided, were issued as final by the AER on the 6 August 2014.

The information contained in the templates relates to the 2014 calendar year only.

1.1 Preparation process

The following diagram provides a high-level summary of UE's approach to preparing the 2014 Annual RIN.



United Energy's response is audited in accordance with Appendix E of the Notice. The audit report and information provided by the AER is verified by statutory declaration.

2. Compliance with AER requirements

2.1 Compliance with Schedule 1 of the Notice

The table below outlines how United Energy has complied with the requirements of Schedule 1 of the Notice.

Clause detail	United Energy response
1. Regulatory accounting statements and non-financial information	
1.1. Provide: **a) the Regulatory Accounting Statements, being the information required in the worksheets in the Microsoft Excel workbook attached at Appendix B, as amended by the AER on 6 August 2014;** **b) the non-financial information required in the worksheets in the Microsoft Excel workbook attached at Appendix C, as amended by the AER on 6 August 2014;**	Appendix A – Annual Financial RIN Excel Template Appendix B – Annual Non-Financial RIN Excel Template
c) a Microsoft Excel workbook that reconciles and explains all adjustments between the Statutory Accounts and the Regulatory Accounting Statements. United Energy must separately list each adjustment to the Statutory Accounts made to derive the Regulatory Accounting Statements, and for each adjustment made: **i. specify the amount of the adjustment** **ii. describe the nature and basis of each adjustment**	Appendix E – Reconciliation of the RIN to the Statutory Accounts
d) a Basis of Preparation demonstrating how United Energy has complied with the Notice, in accordance with this Notice and the Principles and Requirements at Appendix A.	Appendix C – Basis of preparation
e) the Regulatory Accounting Principles and Policies and the Capitalisation Policy for the Relevant Regulatory Year.	Appendix F – Cost Allocation Methodology (CAM) and Capitalisation Policy
f) a statement of the policy for determining the allocation of overheads in accordance with the approved Cost Allocation Method for the relevant Regulatory year.	In accordance with the CAM

Clause detail	United Energy response
1.2 Identify all changes between the Regulatory Accounting Principles and Policies provided in the response to paragraphs 1.1(e). For each change identified: **a) explain the nature of and the reasons for the change;** **b) quantify the effect of the change on the Regulatory Accounting Statements for the current Relevant Regulatory Year.**	Not applicable – no differences
1.3 Identify all changes between the statements of the policy for determining the allocation of overheads in accordance with the approved *Cost Allocation* Method provided in the response to paragraphs 1.1(f). For each change identified: **a) explain the nature of and the reasons for the change;** **b) quantify the effect of the change on the Regulatory Accounting Statements for the current Relevant Regulatory Year.**	Not applicable – no differences
1.4 Identify material difference (where the difference is greater than or equal to 10 per cent) between the amount provided for in the 2011-15 Distribution Determination for the following items: **a) total actual revenue and total forecast revenue;** **b) total actual operating expenditure and total forecast operating expenditure;** **c) total actual maintenance expenditure and total forecast maintenance expenditure;** **d) total actual capital expenditure and total forecast capital expenditure; and** **e) total actual energy sales and total forecast energy sales.**	Appendix G – Explanation of material differences
1.5 Explain the reasons underlying the changes in expected operational activities or drivers that caused each material difference identified in the response to paragraph 1.4.	Appendix G – Explanation of material differences
1.6 Identify each material differences (where the difference is equal to or greater than 10 per cent) between the target performance measure specified in the service target performance incentive scheme and actual performance reported in the response paragraph 1.1(b).	Appendix G – Explanation of material differences

Clause detail	United Energy response
1.7 Explain the reasons underlying the changes that caused each material difference identified in the response to paragraph 1.6.	Appendix G – Explanation of material differences
1.8 Where it is not possible to provide the information in Schedule 1 as required by the Notice, provide: **a) an estimate, using best endeavours to generate the most appropriate estimate; and** **b) the basis for this estimate, explaining why it is the most appropriate estimate; or** **c) if it is not possible to provide an estimate, explain why the information as required by this notice has not been provided, and why an estimate is not able to be derived.**	Appendix A – Annual Financial RIN Excel Template Appendix B – Annual Non-Financial RIN Excel Template Appendix C – Basis of preparation
2. Compliance	
2.1 Explain the procedures and processes used by United Energy to ensure that the distribution services have been classified as determined in the 2011-15 Distribution Determination.	UE has classified distribution services in accordance with the CAM and Capitalisation Policy approved by the AER in line with the 2011-15 Distribution Determination.
2.2 Explain the procedures and processes used by United Energy to ensure that the negotiated service criteria, as set out in the 2011-15 Distribution Determination, have been applied.	Negotiated service criteria have been applied in accordance with the CAM and Capitalisation Policy approved by the AER in line with the 2011-15 Distribution Determination.
2.3 Describe the process United Energy has in place to identify negative change events under clause 6.6.1(f) of the NER and the materiality threshold applied to these events.	Each business area holds responsibility for identifying negative change events under clause 6.6.1(f) of the NER. The respective General Manager formally attests to compliance with 6.6.1 (f) of the NER during the RIN reporting period. The materiality threshold applied is 1 per cent of 1 per cent of the smoothed forecast revenue specified in the final decision for the applicable regulatory year(s), pro rata for the applicable event period.

Clause detail	United Energy response
3. Cost allocation to regulated distribution business	
3.1 Identify each Item in the Regulatory Accounting Statements that is: **a) not allocated on a directly attributable basis but is allocated on a causation basis to the distribution business; or** **b) not allocated on a directly attributable basis and cannot be allocated on a causation basis to the distribution business.**	All costs have been directly allocated. Refer to Appendix H – Cost allocation to regulated distribution business and cost allocation to service segments.
3.2 For each Item identified in the response to paragraphs 3.1(a): **a) state the amount of the item that has been allocated;** **b) explain the method of allocation and reasons for choosing that method; and** **c) state the numeric amount of the allocator(s) used.**	All costs have been directly allocated. Refer to Appendix H – Cost allocation to regulated distribution business and cost allocation to service segments.
3.3 For each Item identified in the response to paragraphs 3.1(b): **a) state its amount;** **b) state whether it was material;** **c) explain the method of allocation and reasons for choosing that method; and** **d) explain the reason(s) why it cannot be allocated on a causation basis.**	All costs have been directly allocated. Refer to Appendix H – Cost allocation to regulated distribution business and cost allocation to service segments.
4. Cost allocation to service segments	
4.1 Identify each item in the Regulatory Accounting Statements that is: **a) Not allocated on a directly attributable basis but is allocated on a causation basis from the distribution business to a service segment; and** **b) Not allocated on a directly attributable basis and cannot be allocated on a causation basis from the distribution business to a service segment.**	All costs have been directly allocated. Refer to Appendix H – Cost allocation to regulated distribution business and cost allocation to service segments.

Clause detail	United Energy response
4.2 For each Item identified in the response to paragraphs 3.1(a): **a) state the amount of the item that has been allocated;** **b) explain the method of allocation and reasons for choosing that method; and** **c) state the numeric amount of the allocator(s) used.**	All costs have been directly allocated. Refer to Appendix H – Cost allocation to regulated distribution business and cost allocation to service segments.
4.3 For each Item identified in the response to paragraphs 3.1(b): **a) state its amount;** **b) state whether it was material;** **c) explain the method of allocation and reasons for choosing that method; and** **d) (explain the reason(s) why it cannot be allocated on a causation basis.**	All costs have been directly allocated. Refer to Appendix H – Cost allocation to regulated distribution business and cost allocation to service segments.
5. Related Party Transactions	
5.1 Identify each Related Party to which a transaction has been conducted	Appendix A – Tab 20
5.2 Identify each transaction relating to the provision of standard control services, alternative control services, AMI or negotiated distribution services between United Energy and a Related party, where the transaction amount is greater than five per cent of the relevant total expenditure or revenue category. Relevant categories are standard control revenues, alternative control revenues, AMI revenues, negotiated distribution services revenues, standard control capex, alternative control capex, AMI capex, standard control operation expenditure, standard control maintenance expenditure, alternative control operations expenditure, alternative control maintenance expenditure, AMI operations expenditure, AMI maintenance expenditure and negotiated distribution services expenditure.	Appendix A – Annual Financial RIN Excel Template – Tab 20
5.3 For each transaction identified in the response to paragraph 5.2: **a) State the name of the Related Party;** **b) Identify any other parties involved;** **c) Explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related**	Appendix A – Annual Financial RIN Excel Template – Tab 20

Clause detail	United Energy response
Party; **d) State the actual costs incurred by the Related Party in providing good(s) or service(s), not including any profit margin or management fee incurred by *United Energy;*** **e) Explain how the actual costs of the good(s) or service(s) incurred was determined;** **f) Explain how the actual costs of the good(s) or service(s) incurred is reflected in the Regulatory Accounting Statements;** **g) Identify the Asset Category, Maintenance Cost category or Operating cost category to which the actual costs) is allocated; and** **h) Explain the basis upon which the actual costs of the good(s) or service(s) were allocated, as identified in the response to paragraph (f), and state the quantum of any allocator applied.**	
6. Capitalisation policy	
6.1 Identify all changes between the Capitalisation Policies provided in the response to paragraph 1.1 (e). **6.2 For each change identified in the response to paragraph 6.1:** **a) state, if any, the financial impact of the change;** **b) state the reasons for the change;** **c) explain the effect of the change, if any, on the actual operating expenditure, actual maintenance expenditure and actual capital expenditure incurred, in comparison to the forecast operating expenditure, forecast maintenance expenditure and forecast capital expenditure determined in the 2011-15 Distribution Determination during the Relevant Regulatory year.**	Not applicable – No changes to the capitalisation policy
7. Demand Management Incentive Allowance	
7.1 Identify each demand management project or program for which United Energy seeks approval.	Appendix H – Demand Management Incentive Scheme Report – 2014
7.2 For each demand management project or program identified in the response to paragraph 7.1: **a) explain:**	Appendix H – Demand Management Incentive Scheme Report – 2014

Clause detail	United Energy response
i. how it complies with the Demand Management Incentive Allowance criteria set out at section 3.1.3 of the demand management incentive scheme; ii. its nature and scope; iii. its aims and expectations; iv. the process by which it was selected, including its business case and consideration of any alternatives; v. how it was/is to be implemented; vi. its implementation costs; and vii. any identifiable benefits that have arisen from it, including any off peak or peak demand reductions	
b) confirm that its associated costs are not: **i. recoverable under any other jurisdictional incentive scheme;** **ii. recoverable under any other Commonwealth or State Government scheme** **iii. included in the forecast capital or operating expenditure approved in the 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination; and**	Appendix H – Demand Management Incentive Scheme Report – 2014
c) explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for United Energy's decision to adjust or not to adjust for other factors and the basis for any such adjustments.	Appendix H – Demand Management Incentive Scheme Report – 2014
7.3 State the total amount of the Demand Management Incentive Allowance spent in the Relevant Regulatory Year, and explain how it was calculated.	Appendix H – Demand Management Incentive Scheme Report – 2014
8. Advanced Metering Infrastructure	
8.1 Describe each efficiency improvement made to United Energy's operations directly or indirectly arising from or associated with the roll out of the Advanced Metering Infrastructure.	**1) Delivering Alternative Control Services at lower cost to consumers and in a more timely manner:** • More than 54,000 connections and disconnections were completed remotely in 2014 using the contactor in the AMI meter. Charges paid by customers for these services have been reduced by more than $30 for each transaction,
8.2 For each efficiency improvement identified in the response to paragraph 8.1:	

Clause detail	United Energy response
a) Explain how it arises from or is associated with the roll out of the Advanced Metering Infrastructure; and **b) If quantifiable, state its amount.**	delivering aggregate savings to customers to date of over $1.6 million for this activity alone; • More than 2,300 unnecessary truck visits to customers' premises have been avoided in 2014by utilising the AMI meter to remotely confirm supply status using the ping functionality. The savings to these customers range from $51 to $115 per truck visit – where the higher amount applies to truck visits outside normal business hours; • More than 5,000 remote meter reconfigurations in 2014 facilitated data collection of net solar energy exported to our network. Avoided site visits to undertake a meter exchange to a bi-directional meter resulted in customer savings of over $80 for each transaction; • More than 1,200 special meter reads were undertaken remotely in 2014 resulting in customer savings of more than $10 per transaction; and • The collection of data remotely allows customers to be billed on actual data and avoids estimated bills and associated customer enquiries and complaints. **2) Managing the network smarter and safer:** • Neutral integrity testing can be undertaken largely remotely avoiding site visits and manual testing at around 65,000 premises pa and saving 26m$pa • Enhanced monitoring of supply to life support customers can be undertaken during storm events using a on demand supply status check via a regular ping to the AMI meter; • Faults can be identified remotely, to avoid wasted truck visits and restore supply more quickly; • Improved voltage data (use of severe over or under voltage data) provides us with a better understanding of equipment failure risks and assessment of damage claims; • Improved power quality data and Engineering Analytics to assess transformer peak load and the likely requirement for transformer upgrades facilitates more efficient use of existing capacity and more efficient investment; • Calculation of dynamic cyclic ratings for distribution transformers enables us to achieve greater use of the spare capacity in the network;

Clause detail	United Energy response
	• Rebalancing of over loaded phases enables us to improve network utilisation on peak demand days, and reduce the need for network augmentation; • Use of end of day interval data to enhance load switching enables us to better manage expected high demand days in high network risk areas; and • Improved identification of theft and stolen meters. **3) Customers have better access to energy consumption data and a broader range of pricing options:** • Over 7% of our residential customers have made use of interval data and have taken up flexible network tariffs; • More than 15,000 customers are accessing detailed information on their electricity consumption via our web portal; and more recently third party energy agents are seeking access to customer data (with their consent) in order to provide customers with improved pricing options; • More than 2,800 customers have taken up the use of In Home Displays to better understand their energy usage and appliance consumption; • UE is also undertaking a number of trials – Summer Demand, Supply Capacity Limiting and Battery Storage to assist with peak demand reduction in constrained areas of the network.
9. Safety and bushfire related expenditure	
9.1 For each safety and bushfire related expenditure, specify and define the relevant asset category to which it relates.	Appendix A – Annual Financial RIN Excel Template – Tab 20
9.2 Identify each material (greater than or equal to 10%) difference, in relation to the asset categories specified in the response to paragraph 9.1, between: **a) actual and forecast volumes;** **b) actual and forecast expenditure; and** **c) actual and forecast unit costs.**	Appendix A – Annual Financial RIN Excel Template – Tab 20

Clause detail	United Energy response
9.3 Provide reasons for each material (greater than or equal to 10%) difference identified in the response to paragraph 9.2.	Appendix A – Annual Financial RIN Excel Template – Tab 20
9.4 Provide reasons for any difference between the actual volumes submitted as part of the Electrical Safety Management Scheme to Energy Safe Victoria and that in the Regulatory Accounting Statements.	Appendix A – Annual Financial RIN Excel Template – Tab 20
10. Sponsorship and marketing	
10.1 Provide the following information for all advertising/marketing expenditure allocated to the distribution business: **a) For expenditure greater than five per cent of the advertising / marketing expenditure allocated to the *distribution business:*** **i. Beneficiary** **ii. Amount** **iii. Purpose** **iv. Proportion of the total advertising / marketing expenditure allocated to the *distribution business* related to:** **1) safety or safety awareness** **2) Managing consumer demand** **3) Promoting *distribution business* brand** **4) Other** **v. Description of the activities undertaken by the beneficiary, supported by the expenditure.**	Not applicable – there were no expenditure amounts greater than five per cent of the advertising / marketing expenditure allocated to the distribution business.
b) For all advertising / marketing expenditure allocated to the *distribution business* not reported under 10.1(a), provide: **i. list of beneficiaries** **ii. total amount** **iii. proportion of the expenditure related to:**	The advertising and marketing expenditure reported represents the proportion of staff costs incurred to develop communications relating to safety and safety awareness for project activities.

Clause detail	United Energy response
1) safety or safety awareness 2) Managing consumer demand 3) Promoting *distribution business* brand 4) Other	
10.2 For each expenditure item identified in response to paragraph 10.1(a), identify the expenditure item in the statutory accounts from which it is derived.	Not applicable
11. Charts	
11.1 Provide a chart that sets out: **a) the group corporate structure of which *United Energy* is a part; and** **b) the organisational structure of *United Energy.***	Appendix K – Charts
12. Audit Reports	
12.1 Provide a Regulatory Audit Report in the form of: **c) a Special Purpose Financial Report in accordance with the requirements set out at Appendix E; and** **d) an Audit Report (for non-financial information) in accordance with the requirements set out at Appendix E.**	Appendix J – Audit reports
12.2 Provide all reports from the Auditor to United Energy's management regarding the audit review and / or auditors' opinions or assessment.	Appendix J – Audit reports
13. Confidential information	
13.1 If United Energy makes a claim for confidentiality over any information provided in accordance with this Notice, United Energy must: **a) comply with the requirements of AER's *Confidentiality Guideline,* as if it extended and applied to responses**	Appendix L – Confidentiality template

Clause detail	United Energy response
in this Notice; **b) provide, in addition to a confidential version of any information, a version of the information that may be published by the AER.**	
13.2 Confirm in writing that *United Energy* consents to the AER publically disclosing (including on the AER website) all information provided in accordance with this Notice, except the confidential version of information the subject of a confidentiality claim under paragraph 13.1.	Refer to Annual RIN submission transmittal email

2.2 Compliance with Schedule 2 of the Notice

United Energy confirms that it prepares and maintains all information in accordance with Schedule 2 of the Notice.

2.3 Compliance with the appendices of the Notice

The table below outlines how United Energy has complied with the requirements of Schedule 1 of the Notice.

Appendix	Details	United Energy response
A	**Principles and requirements**	All information is in accordance with the principles and requirements outlined in Appendix A.
B	**Regulatory accounting statement templates**	Appendix A – Annual Financial RIN Excel Template
C	**Non-financial information templates**	Appendix B – Annual Non-Financial RIN Excel Template
D	**Statutory declaration**	Appendix I – Statutory declaration
E	**Audits**	Appendix J – Audit reports
F	**Activity areas – Cost categories for operating expenditure**	Appendix C – Basis of preparation – Operating expenditure
G	**Asset and capital and maintenance expenditure categories**	N/A
H	**Statement of reasons**	N/A

Appendix A: Annual Financial RIN Excel Template

Note: Refer attached spreadsheet

Appendix B: Annual Non-Financial RIN Excel Template

Note: Refer attached spreadsheet

Appendix C: Basis of preparation – Annual RIN 2014

UNITED ENERGY

1. Overview

United Energy is required to prepare a Basis of Preparation document (this document) which must, for all information:

a) demonstrate how the information provided is consistent with the requirements of the Regulatory Information Notice (RIN);

b) explain the source from which United Energy obtained the information provided;

c) explain the methodology United Energy applied to provide the required information, including any assumptions United Energy made;

d) explain, in circumstances where United Energy cannot provide information:

   1) why it was not possible for *United Energy* to provide the information required;

   2) what steps *United Energy* is taking to ensure it can provide the information in the future;

   3) if an estimate has been provided, the basis of the estimate, including the approach used, assumptions made and reasons why the estimate is *United Energy's* best estimate.

In accordance with the requirements above, this appendix provides details to support the information provided by United Energy in the Microsoft Excel workbooks titled *'United Energy 2014-15 - Annual RIN - Financial Information'* and *'United Energy 2014-15 - Annual RIN – Non-Financial Information'*.

To satisfy the requirements of the Notice, the following information has been provided for each RIN table:

- assessment of data quality;
- data source;
- classification as actual or estimated information, including appropriate justification if estimated;
- methodology and assumptions adopted to prepare the information; and
- any additional comments to assist users of the information to understand the basis of preparation.

The table below outlines the classifications used to assess data quality.

Table 1: Data quality and classifications

Colour coding	Availability of data from NSP's Primary System	Assumptions / methodology
Green	Available and verifiable	Simple – no additional work or minor work around (e.g. data sourced from a secondary system)
Light green	Available with some gaps	Moderate – estimate based on statistically significant sample size
Yellow	Little or no data available	Complex – estimate based on formula, standard parameters or other source
Pink	Little or no data available	Subjective – based on significant estimates, judgements and assumptions

Colour coding	Availability of data from NSP's Primary System	Assumptions / methodology
Black	N/A	Not applicable to relevant NSP

The table below provides the AER definitions for actual and estimated information.

Table 2: Definitions – 'Actual and 'estimated'

Term	Table Heading
Actual information	Information presented in response to the Notice whose presentation is Materially dependent on information recorded in United Energy's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice. 'Accounting records' include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate United Energy's regulatory accounts and responses to the Notice. 'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on.
Estimated information	Information presented in response to the Notice whose presentation is not Materially dependent on information recorded in United Energy's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.

The estimated information is produced using the methodology detailed below. This methodology represents United Energy's best estimate as applied over prior reporting periods and sourced from United Energy's information systems, audited information (where applicable), internal management reports and subject matter expert professional judgement based on the nature of United Energy's operations. United Energy is unable to provide information with greater accuracy than that provided in its response.

Where estimates have been provided, United Energy is currently considering the feasibility of improvement opportunities to allow actual information to be provided in the future.

Appendix C: Basis of preparation – Annual RIN 2014

The following tables outline the basis of preparation of the information provided in the Microsoft Excel Workbook titled '*United Energy 2014-15 - Annual RIN –Financial Information'.*

Table 3: Annual Financial RIN details

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
1a	**Income**	-	-		F	-	Actual / Estimate	As per relevant Annual Financial RIN tabs.	Consolidation of data from tabs contained within the Annual Financial RIN.	-	-
2	**Demand and Revenue**	1	Standard Control Services Revenue - Current Year		F	Based on reported monthly energy. CIS/SAP Billing System and accrual data extracts. Additional non DUOS tariff Revenue has been sourced from SAP Financial Accounts	Actual / Estimate	The latter months of the reporting period have some accrued components for the following reasons. - NMIs can be billed for up to three months in arrears from the consumption period. - Delayed billing for other reasons.	Sum up annual revenue grouped by each tariff, with adjustments for Revenue from SAP Financial Accounts.		A high percentage of actual billed data has been used.
					NF	CIS/SAP Billing System and accrual data extracts	Actual / Estimate	The latter months of the reporting period have some accrued components for the following reasons. - NMIs can be billed for up to three months in arrears from the consumption	Based on reported monthly energy. Sum annual energy (GWh) components grouped by each tariff.		A high percentage of actual billed data has been used.

Appendix C: Basis of preparation – Annual RIN 2014

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
								period. - Delayed billing for other reasons.			
		2	Standard Control Revenue - Prior Year		F / NF	Annual RIN 2013	Actual		As per Annual RIN reported revenue for 2013.		
		3	AMI - Current Year		F / NF	SAP Financial accounts	Actual		Sum transactions based on SAP account extract for the following; - Meter data services - Meter Provision Charges Individual breakdown to the tariff categories has been provided by the BI Rpt RM 1.16-3 report		
					NF	CIS+/SAP Billing System	Actual		Sum transactions based on SAP account extract for the following; - Meter data services - Meter Provision Charges Individual breakdown to the tariff categories has been provided by the Finance MRO from the CIS+/SAP billing systems		
		4	AMI - Prior Year		F	Annual RIN 2013	Actual		As per Annual RIN reported AMI revenue for 2013.		
					NF	Annual RIN 2013	Actual		As per Annual RIN reported AMI meter count for 2013.		
		5	Public Lighting - Current Year		F	SAP Financial	Actual		Sum transactions based on SAP account extract for public lighting O&M. Individual breakdown into tariff		

Appendix C: Basis of preparation – Annual RIN 2014

<table>
<tr><th>Tab</th><th>Table Name</th><th>Table</th><th>Table Title</th><th>Data quality</th><th>Fin / Non-fin</th><th>Data source</th><th>Actual / Estimate</th><th>Justification (if estimated)</th><th>Methodology (Actual & Estimated)</th><th>Assumptions (Actual & Estimated)</th><th>Additional Comments</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td>accounts and GIS Report</td><td></td><td></td><td>category has been provided in the GIS monthly report</td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>NF</td><td>GIS Report</td><td></td><td></td><td>Sum transactions based on SAP account extract for public lighting O&M
Individual breakdown into tariff category has been provided in the GIS monthly report as the number of MRUs per the tariff category</td><td></td><td></td></tr>
<tr><td></td><td></td><td>6</td><td>Public Lighting – Prior Year</td><td></td><td>F / NF</td><td>Annual RIN 2013</td><td>Actual</td><td></td><td>As per Annual RIN 2013.</td><td></td><td></td></tr>
<tr><td></td><td></td><td>7</td><td>Total Annual Retailer Charges</td><td></td><td>F</td><td>SAP Financial Accounts and information from Table 1, 3, 5</td><td>Actual</td><td></td><td colspan="2">The total TARC has been calculated as per the table below.
<table>
<tr><th>Tariff categories</th><th>TARC Revenue</th></tr>
<tr><td>Distribution *</td><td>371,127.7</td></tr>
<tr><td>Rebates</td><td>-123.0</td></tr>
<tr><td>F' (Fire Factor)</td><td>892.0</td></tr>
<tr><td>PFIT/TFIT</td><td>17,701.3</td></tr>
<tr><td>AMI</td><td>93,178.2</td></tr>
<tr><td>TUOS/Grid Fees</td><td>109,583.2</td></tr>
<tr><td>Public Lighting (OMR)</td><td>7,482.0</td></tr>
<tr><td>Profit from Sale of Fixed Assets (loss on sale of fixed assets not included)</td><td>-</td></tr>
<tr><td>Other excluded services</td><td>7,361.2</td></tr>
<tr><td>Other activities non-regulated (pole rental plus reserve capacity)</td><td>6,173.2</td></tr>
<tr><td>Total</td><td>613,376</td></tr>
</table>
*Distribution revenue includes prior year accrued revenue adjustment of $18 million.
SAP Financial Accounts have been applied with information from Table 1, 3, 5 where applicable.</td><td></td></tr>
</table>

Appendix C: Basis of preparation – Annual RIN 2014

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
3a	**Capex (T) - Total**	1	Standard Control Service		F	SAP	Actual		Extracted a list of statutory capital additions from SAP and categorised it based on the SAP expenditure type field. The voltage has predominately been determined from the asset class the expenditure resides against on the fixed asset register.	New customer connections adjusted for capital allocated to Other Alternative Control	
		2	Material Difference Explanation		NF	N/A	N/A		Analysed the makeup of the forecast and actual capital and compared the two.		
		3	Capex by Asset Class		F	SAP	Actual		Data generated as follows: • 'Subtransmission' totals as per Table 1 • 'HV' and 'LV' totals as per Table 1 • 'SCADA/Network Control' total as per Table 1 • 'Non network - IT' total as per Table 1 • 'Non network - other' total as per Table 1 • 'Metering - Non AMI' total as per Table 1 • 'AMI' total as per Table 4 • 'Public Lighting - Total Additions' total as per Table 4 • 'Other Alternative Control - Total Additions' total as per Table 4 • 'Negotiated Services' total on Table 4 of this schedule • 'Unregulated' total as per Table 4	UE does not capitalise any interest charges or equity raising costs directly to capital expenditure so the total for this category is zero	
		4	Other Capex		F	SAP	Actual		Extracted a list of statutory capital additions from SAP and		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
						Service provider costs			categorised based on the SAP expenditure type field. For fields relating to Other - fee based services, Other - quoted services, Negotiated services and Unregulated SAP data pertaining to ACS costs and revenue billed, including external service providers' unit costs per invoices applied against ACS service orders was used.		
		5	Customer Contributions by Asset Class		F	SAP	Actual		Data download from the United Energy general ledger includes five general ledger accounts: 60360 (Excluded Services – Non-Regulated), 60400 (Customer Contributions – General), 60401 (Customer Contributions - P/L), 60402 (Customer contributions - In Kind) and 60403 (Customer Contributions – Quoted). The data was split by 'Material type' enabling the revenue to be allocated to the appropriate Customer Contribution by Asset Class.		
		6	Disposals by asset class		F	SAP Fixed Asset retirement report	Actual		Extracted a list of statutory retirements with proceeds and categorised it based on the SAP asset class field.	None	Proceeds from the sale of assets has been reported
3b	**Capex (M) - Total Margins**	1	Standard Control Service		F	SAP	Actual / Estimate		**Reinforcement** Extracted a list of related parties' statutory capital additions from SAP and determined the value of capital related to margin and	**Reinforcement** The voltage split has been determined by using the actual total, allocated on the basis of the voltage split reported on schedule 3a. Capex (T).	

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									categorised it based on the SAP expenditure type field. **New customer connection** As above **Reliability and quality maintained** Extracted a list of statutory capital additions from SAP and categorised based on the SAP expenditure type field.	**New customer connection** Assumed that none of the capital without a project number allocated to Other Alternative Control had a related party margin. **Reliability and quality maintained** The voltage split has been determined by using the actual total, allocated on the basis of the voltage split reported on schedule 3a. Capex (T)	
		2	Material Difference Explanation		NF	N/A	N/A		Analysed the makeup of the forecast and actual capital and compared the two.		
		3	Capex by Asset Class		F	SAP	Actual		Data generated as follows: • 'Subtransmission' totals on Table 1 of this schedule • 'HV' and 'LV' totals on Table 1 of this schedule • 'SCADA/Network Control' total on Table 1 of this schedule • 'Non network - IT' total on Table 1 of this schedule • 'Non network - other' total on Table 1 of this schedule • 'Metering - Non AMI' total on Table 1 of this schedule • 'AMI' total on Table 4 of this schedule • 'Public Lighting - Total Additions' total on Table 4 of this schedule • 'Other Alternative Control - Total Additions' total on Table 4 of this schedule • 'Negotiated Services' total on Table 4 of this schedule	UE does not capitalise any interest charges or equity raising costs directly to capital expenditure so the total for this category is zero	

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									• 'Unregulated' total on Table 4 of this schedule		
		4	Other Capex		F	SAP Service provider costs	Actual		Extracted a list of related parties' statutory capital additions from SAP and determined the value of capital related to margin and categorised it based on the SAP expenditure type field. For fields relating to Other - fee based services and Other - quoted services SAP data pertaining to ACS costs and revenue billed, including external service providers' unit costs per invoices applied against ACS service orders was used. For data relating to Negotiated services and Unregulated extracted a list of statutory capital additions from SAP and categorised it based on the SAP expenditure type field.		
		5	Customer Contributions by Asset Class		F	SAP	Actual		All customer contributions are directly received by UE with no related party margin so all actual fields in this table are zero.		
		6	Disposals by asset class		F	SAP	Actual		All proceeds received on the sale of fixed assets are either directly received by UE or received with no related party margin so all actual fields in this table are zero.		Proceeds from the sale of assets have been reported.
5	**Capex Tax**	1	Tax Standard Lives and Capex Additions - Standard		F	SAP	Actual / Estimate	Multiple tax lives are used in this category, depending on the nature of the	Capex additions are actual. Data generated as follows: • Schedule 3a. Capex(T), Table 1, column 'Subtransmission' and SAP		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
			Control Services					capital expenditure.	• Schedule 3a. Capex(T), Table 1, columns 'HV' and 'LV' and SAP – Distribution system assets • Schedule 3a. Capex(T), Table 3, row 'Neutral screen services' • Schedule 3a. Capex(T), Table 3, row 'Distribution Transformers upgrades' • Schedule 3a. Capex(T), Table 1, row 'SCADA/Network Control' & SAP • Schedule 3a. Capex(T), Table 1, row 'Non network general - IT' & SAP • Schedule 3a. Capex(T), Table 1, row 'Non network general - Other' & SAP • Schedule 3a. Capex(T), Table 3, row 'Equity raising costs' • As there is no metering reported in Schedule 3a. Capex(T), table 1, this is zero • As there is no public lighting reported in Schedule 3a. Capex(T), table 1, this is zero The tax standard lives have been determined as a weighted average from an analysis of the actual tax rates used on capital allocated to this category and are subject to change.		
		2	Standard Control Services - Excl Metering		F	SAP	Actual / Estimate	Multiple tax lives are used in this category, depending on the nature of the capital expenditure.	Capex additions are actual. Data generated as follows: • Schedule 3a. Capex(T), Table 1, rows 'Demand Related' • Schedule 3a. Capex(T), Table 1, row 'Reliability & quality maintained'		

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									• Schedule 3a. Capex(T), Table 1, row 'Environmental, safety & legal' • Schedule 3a. Capex(T), Table 1, row 'SCADA/Network Control' • Schedule 3a. Capex(T), Table 1, row 'Non network general - IT' • Schedule 3a. Capex(T), Table 1, row 'Non network general - Other' The tax rates have been determined as a weighted average from an analysis of the actual tax rates used on capital allocated to this category and are subject to change for the following asset classes: • Demand related capital expenditure • Environment, safety and legal • SCADA/Network control • Non-network general assets – IT • Non-network general assets - other		
		3	Metering		F	SAP	Actual / Estimate	Multiple tax lives are used in this category, depending on the nature of the capital expenditure.	Capex additions are actual. The tax standard lives has been determined as a weighted average from an analysis of the actual tax rates used on capital allocated to this category and are subject to change. Data generated as follows: • Schedule 3a. Capex (T), Table 4, row 'Remotely read interval meters & transformers' • Schedule 3a. Capex (T), Table 4, row 'Metering data services (IT)' • Schedule 3a. Capex (T), Table 4, row 'AMI communication' • Schedule 3a. Capex (T), Table 4, row 'Metering data services (Other)'	Tax rate is the same as that used in table 1 of this schedule for this category.	

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
6a	**Maint(T) - Total**	1	Maintenance Expenditure		F	SAP	Actual		SAP download of every WBS element by MAT code which determines the line classifications and regulatory categories.	• ACS cost components are non-routine & condition based. • Vegetation removal costs are the same as vegetation removal revenue and adjusted from Condition based.	Financial
		2	Explanation of Material Difference		NF	N/A	N/A		Analysed the makeup of the forecast and actual capital and compared the two.		
		3	Other Network Maintenance Costs		F	SAP	Actual		SAP download of every WBS element by MAT code which determines the line classifications and regulatory categories		
6b	**Maint(M) - Margins**	1	Maintenance Expenditure		F	SAP	Actual		SAP extract by ZNX Limb 2 and Limb 3 have been deemed as related party margins.		
		2	Explanation of Material Difference		NF	N/A	N/A		Qualitative analysis of difference between forecast and actual figures.		
		3	Other Network Maintenance Costs		F	SAP	Actual		SAP extract by ZNX Limb 2 and Limb 3 have been deemed as related party margins.		
8a	**Operating (T) - Total**	1	Operating Expenditure		F	SAP Audited statutory accounts	Actual		Data generated from SAP. All costs were directly allocated in line with the United Energy's approved Cost Allocation Methodology – refer to Appendix F.		
		2	Explanation of Material Difference		NF	N/A	N/A		Qualitative analysis of difference between forecast and actual figures.		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
		3	Operating costs - Other standard control services		F	SAP	Actual		Data generated from SAP. All costs were directly allocated in line with the United Energy's approved Cost Allocation Methodology – refer to Appendix F.		
		4	Operating Expenditure - Non-Recurrent Network Operating Costs								Not applicable.
8b	**Operating (M) - Margin**	1	Operating Expenditure								No margins for operating expenditure.
		2	Explanation of Material Difference								No margins for operating expenditure.
		3	Operating costs - Other standard control services								No margins for operating expenditure.
		4	Operating Expenditure - Non-Recurrent Network Operating Costs								No margins for operating expenditure.

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
13	**Avoided Cost Payments**	-	-						Verified nil value based on SAP transactions.		
14	**Alt Control & Others**	-	Alt Control & Others		F	SAP Service provider costs	Actual		SAP data pertaining to ACS costs and revenue billed, including external service providers' unit costs per invoices applied against ACS service orders. For 'operating non-regulated costs' refer cost allocation methodology. For efficient / non-energy efficient luminaries, transaction codes (MAT codes) attached to each project code (WBS codes) element determines public lighting costs, which are pro-rated to efficient or non-energy efficient on the revenue split basis.	Vegetation removal costs assumed to be the same as vegetation removal revenue (recoverable).	
15	**EBSS**	1	Opex for EBSS Purposes		F	SAP	Actual		Data extracted from SAP as per AER definitions.		
		2	Explanation of Capitalisation Policy Changes								
16	**Juris Scheme**	-	Jurisdictional Scheme Payments		F	SAP	Actual		Data extracted from SAP as per AER definitions.		
17	**DMIS-DMIA**	1	DMIA Undertaken		F	SAP	Actual		Data extracted from SAP based on WBS transaction report as per AER definitions.		

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
		2	DMIA Expenditure in the Previous Reporting Year		F	Annual RIN 2013	Actual		As per 2013 Annual RIN.		
		3	Foregone Revenue in the Regulatory Reporting Year								
18	**Self Insurance**	*All*	-								UE does not self insure.
19	**CHAP**	1	The Aggregate Effect of the Change in Accounting Policy on the Balance Sheet and Income Statements								
		2	Description and Reason for the Change in Accounting Policy								
20	**Related Party**	1	Payments made by United Energy to Related Party under CONTROL or INFLUENCING Ownership		F	SAP Billing documents	Actual		Zinfra – Contract charges are verified through billing documents. Actual costs exclude margins. UEM – Total billing within the year. UEDH – Total management fee for the year based on DUET calculations.		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
		2	Composition of Margins in Relation to Table 1								
21	**AMI**	1	Standard Control Asset Base - Metering		F	SAP	Actual		Data extracted from SAP as per AER definitions.		
		2a	Number of meters installed		F	CIS+ SAP	Actual and estimate	Adds & Alts service orders has no clear detail of meter type. So we require estimation of meter types. This is only a small portion of installed volumes.	**Accumulation and MRIM meters** Based on CIS+ data **AMI meters** Total 2014 installs counted as sum of below: • ZMRO, ZRNC Service orders in SAP (128,212). • Net AMI transferred to SAP (this is a negative number as some of these meters counted in ZMRO service are part of Type 6 to 5 conversion) (-2,390) • ZRAA service orders where meter replacements were done. (CIS Adds&Alts service orders ignored as majority of orders done in SAP for 2014) (3368). Meter classification has been based on the same ratio as installed volumes obtained from the SAP-IQ09 report.	As ZRAA service orders do not completely describe the type of meter, the total AMI numbers (129,190) have had their meter types based on the Installed report.	
		2b	Cumulative number of meters		NF	CIS+ SAP	Actual		**Accumulation and MRIM meters** Based on CIS+ data **AMI meters** Based on SAP installed meter report		

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
		3	AMI meter reconciliation		NF	SAP	Actual / Estimate	The MRO program is in completion stage. Issues have emerged in the transition from CIS to SAP which has meant that estimates are required	**Abolishments** Calculated as difference between closing number of meters and sum of opening number of meters and installs less AMI meter for AMI meter replacements. **AMI meter for AMI replacements** Based on SAP reports	AMI meter for AMI meter replacements' number is tracked in SAP for AMI installations. CIS+ replacements are estimated as zero as they are not tracked separately for meter replacements.	
		4	Number of meter read quantity – end of year		NF	CIS+	Actual		**Accumulation and MRIM meters** Based on CIS+ data **AMI meters** Based on SAP installed meter report		
22	**Safety and Bushfire**	1	Asset groups: Definitions, Cost-Allocation Basis and Methodology		NF	Spreadsheet of the agreed program with ESV.	Actual		This table is completed based on the agreed programs with Energy Safe Victoria (ESV). Country Fire Authority (CFA) determined the demarcation of bushfire risk areas and the corresponding bushfire risk rating. Programs that pertained to UE's assets located in bushfire risk areas were categorised as bushfire related. All other program were ESMS or ESL or non-ESL related. The allocation of cost to asset group was based on the definition in the Electricity Distribution Price Review (EDPR) which is requested by the Regulatory Team.		
		2	Bushfire Related		NF	ESV Annual Safety report EDPR 2011-	Actual		Volume information has been provided by the quantity of service performed by the service		Categorisation of each program (completed in Table

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
			Expenditure (Volumes)			2015 submission			providers and also personnel in UED Asset Management. This information has then been provided to Energy Safe Victoria in the ESV Annual Safety Report. Volume changes may have occurred post submission to ESV.		1) shall be used to determine whether data for each program will be entered into Table 2; only programs categorised as 'Bushfire' shall have data entered in Table 2. All other lines shall be entered as zero or N/A.
		3	Safety Related Other - ESL, Non ESL and ESMS (Volumes)		NF	ESV Annual Safety report EDPR 2011-2015 submission	Actual		Volume information has been provided by the quantity of service performed by the service providers and also personnel in UED Asset Management. This information has then been provided to Energy Safe Victoria in the ESV Annual Safety Report. Volume changes may have occurred post submission to ESV.		Categorisation of each program (completed in Table 1) shall be used to determine whether data for each program will be entered into Table 2; only programs categorised as 'ESL', 'ESMS' or 'Non-ESL' shall have data entered in Table 3. All other lines shall be entered as zero or N/A.
		4	Bushfire Related Expenditure ($ Nominal - Excluding Margins and Overheads)		F	SAP EDPR 2011-2015 Submission	Actual		For calendar year 2014, AER expected expenditure for each program was obtained from UE General Manager of Asset Management. In future years it is expected to be provided by UE's regulatory team and based on the AER's final determination for years 2011 – 2015.		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									Expenditure on actual 2014 expenditure has been recorded in SAP and has been extracted, filtered and sorted using MAT codes into categories required by the RIN.		
		5	Safety Related Other - ESL, Non ESL and ESMS ($ Nominal - Excluding Margins and Overheads)		F	SAP EDPR 2011-2015 Submission	Actual		For calendar year 2014, AER expected expenditure for each program was obtained from UE General Manager of Asset Management. In future years it is expected to be provided by UE's regulatory team and based on the AER's final determination for years 2011 – 2015. Expenditure on actual 2014 expenditure has been recorded in SAP and has been extracted, filtered and sorted using MAT codes into categories required by the RIN.		
		6	Bushfire Related Expenditure ($ Nominal - Margins and Overheads)		NF	SAP EDPR 2011-2015 Submission	Actual		Expenditure on Bushfire Related programs has been recorded in SAP and has been extracted, filtered and sorted using MAT codes into categories required by the RIN. The SAP data records actual margins and overheads. No expected expenditure was provided in 2010 as part of the 2011-2015 EDPR submission and hence, this column shall be entered as zero.		
		7	Safety Related Other - ESL,		NF	SAP EDPR 2011-	Actual		Expenditure on Safety Related programs has been recorded in SAP and has been extracted,		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
			Non ESL and ESMS ($ Nominal - Margins and Overheads)			2015 Submission			filtered and sorted using MAT codes into categories required by the RIN. The SAP data records actual margins and overheads. No expected expenditure was provided in 2010 as part of the 2011-2015 EDPR submission and hence, this column shall be entered as zero.		
		8	Bushfire Related Expenditure ($ unit cost)		F	SAP EDPR 2011-2015 Submission	Actual		Expenditure on Bushfire Related programs has been recorded in SAP and has been extracted, filtered and sorted using MAT codes into categories required by the RIN. Actual unit costs are calculated as the total expenditure for each program in calendar year 2014 and divided by the total volumes. No expected expenditure was provided in 2010 as part of the 2011-2015 EDPR submission and hence, this column shall be entered as zero.		
		9	Safety Related Other - ESL, Non ESL and ESMS ($ unit cost)		NF	SAPEDPR 2011-2015 Submission	Actual		Expenditure on Safety Related programs has been recorded in SAP and has been extracted, filtered and sorted using MAT codes into categories required by the RIN. Actual unit costs are calculated as the total expenditure for each program in calendar year 2014 and divided by the total volumes.No expected expenditure was provided in 2010 as part of the 2011-2015		

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									EDPR submission and hence, this column shall be entered as zero.		
		10	Safety Improvement Outcomes Reported to ESV (Volumes)		NF	ESV Annual Safety report	Actual		The table was populated based on the ESV monthly report after the December updates. The Year To Date (YTD) data was used to complete the Safety Improvement Programme Outcomes column.		
		11	Reconciliation of Safety Improvement Outcomes reported to ESV and AER (Volumes)		NF				There should be no variance between the safety improvement outcomes reported to ESV and AER as AER defers to ESV safety requirements.		
		12	Bushfire-Related Expenditure - Approved Under Pass-Through Applications (Volumes)								UE has proactively managed bushfire risks by including bushfire related programs in the core programs listed in Table 1.
		13	Bushfire-Related Expenditure - Approved Under Pass-Through Applications ($ Nominal - Excluding								UE has proactively managed bushfire risks by including bushfire related programs in the core programs listed in Table 1.

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
			Margins and Overheads)								
		14	Bushfire-Related Expenditure - Approved Under Pass-Through Applications ($ Nominal - Margins and Overheads)								UE has proactively managed bushfire risks by including bushfire related programs in the core programs listed in Table 1.
23	Shared Asset	1	Total Unregulated Revenue earned with Shared Assets		F	SAP	Actual		Data extracted from SAP as per AER definitions.		
		2	Shared Asset Unregulated Services and Apportioned Revenue								
24	Unmetered Supply	-	Unmetered Supply Tariff Quantity Data Template (Actual t-2)		NF	2014 pricing proposal model	Actual		Proposed 2014 Unmetered Supply Tariff Refer to '2014 Unmetered supply' worksheet. Qt-2 (2012) table in 'Proposed 2014 Unmetered Supply Tariff' section		
25	Actual t-2 Distr Tariff	-	Tariff Quantity Data Template (Actual t-2)		F / NF	2013 & 2014 pricing proposal model	Actual		Tariff Quantity Data Template 2012 Distribution Tariff Revenue Refer to 'Prop2014DistTar' worksheet in 2014 pricing proposal model.	UED assumes that this information is designed to reflect the 2012 information.	2012 tariff data was not included in 2014 pricing proposal model so have used

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
			Distribution Tariff Revenue						Refer to 'Prop2013DistTar' worksheet in 2013 pricing proposal model.		2013 pricing proposal model.
26	Actual t-2 Trans Tariff	-	Tariff Quantity Data Template (Actual t-2) Transmission Tariff Revenue		F / NF	2014 pricing proposal model	Actual		Tariff Quantity Data Template 2012Transmission Tariff Revenue Refer to 'Act2012TransRev' worksheet.		
27	TUoS Cost Audit (t-2)	-	TUoS cost audit template (t-2)		F	2014 pricing proposal model	Actual		Actual 2012 TUoS cost audit template Refer to 'TUoS cost audit template' worksheet.		
28	Actual t-2 Juris Revenue	-	Tariff Quantity Data Template (Actual t-2) Jurisdictional Scheme Tariff Revenue		F / NF	2014 pricing proposal model	Actual		Actual 2012 Jurisdictional Scheme Revenue Refer to 'Act2012JSRev' worksheet.		
29	Juris Cost Audit Template	-	Jurisdictional amount cost audit template		F	2014 pricing proposal model	Actual		Actual 2012 Jurisdictional scheme amounts Refer to 'JS cost audit template' worksheet.		

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The following tables outline the basis of preparation of the information provided in the Microsoft Excel Workbook titled '*United Energy 2014-15 - Annual RIN – Non-Financial Information'.*

Table 4: Annual Non-Financial RIN details

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
1a	**STPIS Reliability**	1	SAIDI (System Average Interruption Duration Index)		NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. SAIDI performance is calculated in accordance with AER definitions. These events are then filtered further for excluded events and MED. MED and excluded events are determined in accordance with AER definitions.		UE have no 'long rural' or CBD feeder classification and information is therefore not provided. Calculations are completed in accordance with AER definitions. The average distribution customer numbers used in calculations is taken from RIN 1a Table 4.
		2	SAIFI (System Average Interruption Frequency Index)		NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. SAIFI performance is calculated in accordance with AER definitions. These events are then filtered further for excluded events and MED. MED and excluded events are determined in accordance with AER definitions.		
		3	MAIFI (Momentary Average		NF	From 31 December 2013 to 31 December 2014, the data	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and		

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
			Interruption Frequency Index)			was sourced from the Distribution Management System Database.			adjusted for temporary switching arrangements. MAIFI performance is calculated in accordance with AER definitions. These events are then filtered further for excluded events and MED. MED and excluded events are determined in accordance with AER definitions.		
		4	Distribution Customer Numbers		NF	The customer numbers are extracted from our GIS data base system.	Actual		Customer numbers are extracted from our GIS system for the start and the end of the reporting period.		
1b	**STPIS Customer Performance**	1	Telephone Answering		NF	Aegis Daily Report (raw) – Faults Desk	Actual		Number of calls received and number of calls answered within 30 seconds is extracted from the Aegis Daily Report (raw) – Faults Desk and used to populate the "Total" column. This report is then filtered to remove MED and populate the "Total – after removing excluded events" column.		
		2	New Connections			GIS Connections Monthly Report SAP – Number of connections not provided on or before agreed date.			New Connections figure extracted from the Connections Monthly Report generated by the GIS Database. Number of connections not provided on or before agreed date – sum of number of GSL payments for connections based on SAP data.		
		3	Streetlight Repair		NF	SAP Financial accounts	Actual		Calculated as average of streetlights held over 12 months		

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Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
						DMS public lighting report			as per SAP as per AER definitions Figures relating to street light repairs and GSL payments extracted from the DMS Public Lighting Report as per AER definitions		
1c	**STPIS Daily Performance**	1	Daily Performance Data (Unplanned)		NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. MAIFI performance is calculated in accordance with AER definitions. These events are then filtered further for excluded events.		
		1	Daily Performance Data (Unplanned)-Customer Service		NF	Aegis Daily Report (raw) - Faults Desk only	Actual		Data is extracted from Aegis Daily Report, as per AER definition.		
1e	**STPIS Exclusions**	1	Exclusions		NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. These events are then filtered further to include only excluded unplanned events. The event category column is filled in manually in accordance with the definitions in the AER's STPIS document.		The "Duration of interruption (unplanned mins)" is not applicable as supply to customers is progressively restored.

Appendix C: Basis of preparation – Annual RIN 2014

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									MED and excluded events are determined in accordance with AER definitions.		
1f	**STPIS - GSL**	1	Guaranteed Service Levels - Jurisdictional GSL Scheme		F	SAP (DMS / Aegis used to develop assumptions for application to SAP data)	Estimate	Discrepancies between DMS, Aegis and SAP systems due to timing differences in data recording and processes. IT systems upgrades are currently underway to address this issue.	GSL payments for missed appointments were taken directly from SAP. As they were reported separately. To determine the breakdown of GSL payments for the remaining types (connections, reliability of supply and faulty streetlights), the proportion of each payment type as per the Aegis reports and DMS operational reports were applied to the SAP GSL payments total less payments for missed appointments. The totals for each GSL payment type were then further broken down into each subcategory (e.g. 1-4 day delay or 5+ day delay for connections) by using the same proportions as the relevant Aegis report / DMS operational report. To determine the number of each type of payment, the dollar figures were divided by the average value of GSL payments for each subcategory determined from the relevant Aegis report / DMS operational report.	The proportions of GSL payment types in DMS and Aegis systems are the same as the proportions of GSL payment types in SAP, with the exception of GSL payments for missed appointments, which are reported separately.	
		2	Guaranteed Service Levels – AER GSL Scheme		NF	**Appointments and connections** Aegis Service Desk Appointments	Actual		**Appointments** UE makes appointments for the following: Service Desk Appointments made with Skilltech to conduct: • Meter investigations		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
						Aegis Connections Monthly Report **Streetlight data** SAP (number of streetlights) DMS (streetlights out during period, number of business days to repair, not repaired by fix by date)			• Meter Faults • Re-energisations New Connections Appointments made with ZNX and Tenix: • Adds/Alts • Abolishments • Solar connections **Connections** As per AER definition – Data from Aegis report. **Streetlights** • Number of streetlights - Average number of streetlights as per SAP • Streetlights out during period - as per DMS • Not repaired by 'fixed by date' – Number of GSL payments plus DMS operational data for streetlights not repaired within 7 working days • Streetlights not repaired within 2 business days – Number of GSL payments • Number of business days to repair – as per DMS **Planned interruptions** As per DMS data for planned outages.		
2	**Customer service**	1	Quality of supply		NF	Web Reporter of ION Enterprise - UE Database	Actual		PQ analysers are installed at every zone substation and at the end of the longest feeder of every zone substation and collect voltage variation data. Web Reporter of ION Enterprise has been used to define, generate, and manage comprehensive reports, based on information		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									extracted from the meters and contained in the UE Database. Note: The first six rows of the RIN - Quality Supply Table 1 cannot be completed due to a lack of measurement capability for such events.		
		2	Complaints - Technical Quality of Supply		NF	Claims Database (1/1/2014 - 14/12/2014), UE SAP CRM (15/12/2014-31/12/2014)			The number of complaints classified by customer resolution agents as relating to quality of supply complaints (recorded by UE as 'Regulatory Category 1'). The complaints sub-categories (recorded by UE as 'Regulatory Category 2') and likely causes (recorded by UE as 'Regulatory Category 3') for quality of supply complaints recorded in the UE system are the same as those requested by the AER. Therefore, data has been directly extracted from the system in the relevant categories.		
		3	Customer Service		NF	Aegis Connections Monthly Report Aegis Daily Report (raw) - Faults Desk only Aegis Monthly Report (Faults tab) (Refer to Tab 1f details for streetlight data)	Actual		**Timely provision of services** A specific date is not agreed with customers; therefore, this number represents the number of connections not made within the agreed period. **Streetlight data** *As per Tab 1f – STPIS GLS data* **Call centre performance** • Calls to call centre fault line – total all months (Jan – Dec) for Total number of calls offered to the automated switchboard		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									• Calls to fault line answered within 30 seconds – the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to: (a) calls to payment lines and automated interactive services (b) calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator (where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned). – Number excludes Major Event Days. • Calls to fault line (average waiting time before call answered) – average of all months (Jan - Dec) for average speed of answer, including Self Serve		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
									• Calls abandoned (percentage) – YTD average for abandon calls over 30 seconds • Call centre (number of overload events) – total all months (Jan – Dec) for Number of Overload Events **Complaints** Calls that could not be resolved through initial contact with the UE call centre and were forwarded to the Complaints Resolution team during the year. Note: complaints do not include financial claim related calls.		
4a	**Network Performance - Feeder**	1	Annual Feeder Reliability Data		NF	Network Planning Team and Network Performance Analyser	Actual		The Feeder ID is obtained from the Network Planning Team. Both Description of Feeder and Classification are obtained from the Network Performance Analyser. Outages both Planned and Unplanned are not necessarily recorded at the end of each day.		UE has produced a number of documents that contain instructions on how the data required for the RIN category is to be obtained and populated. These documents include detailed methodologies to provide both actual and estimated data. The Basis of Preparation against each relevant RIN category is a summary of the methodology detailed within these UE produced documents. For this particular RIN, document UE PR 2302 was referenced.

Appendix C: Basis of preparation – Annual RIN 2014

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
											UE have no 'long rural' or CBD feeder classification and information is therefore not provided. Calculations are completed in accordance with AER definitions. The average distribution customer numbers used in calculations is taken from RIN 1a Table 4. Feeder classification is determined in accordance with AER definitions.
					NF	Geographical Information System AM/FM Reports	Actual		Asset data in the AM/FM reports is updated monthly from UE's GIS and presented in user friendly tables.		
					NF	Network Planning Team	Actual		The Maximum Demand is obtained from the Network Planning Team who uses actual metered data.		
					NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. These events are then filtered further for Energy not supplied (unplanned) and Energy not supplied (planned).		

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
					NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. These events are then filtered further for total number of unplanned outages and statistics. AER definitions for SAIDI, SAIFI, MAIFI and MED's are used in the calculations.		
					NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. The SAIDI for each feeder is then evaluated against the SAIDI threshold based on the 'Feeder classification' column. If the total SAIDI for a feeder exceeds the SAIDI threshold of the feeder classification, it is deemed a low reliability feeder (i.e. Yes). Otherwise, it is not a low reliability feeder (i.e. No).		
4c	**Network Performance - Reliability**	1	Planned Outages		NF	From 31 December 2013 to 31 December 2014, the data was sourced from the Distribution Management System Database.	Actual		Raw data is downloaded from the Distribution Management Database. The data is "cleansed" to remove duplications and adjusted for temporary switching arrangements. These events are then filtered further for planned outages and SAIDI and SAIFI calculated in accordance with AER definitions.		UE has produced a number of documents that contain instructions on how the data required for the RIN category is to be obtained and populated. These documents include detailed methodologies to

Appendix C: Basis of preparation – Annual RIN 2014

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Actual / Estimate	Justification (if estimated)	Methodology (Actual & Estimated)	Assumptions (Actual & Estimated)	Additional Comments
											provide both actual and estimated data. The basis of preparation against each relevant RIN category is a summary of the methodology detailed within these UE produced documents. For this particular RIN, document UE PR 2302 was referenced. UE have no 'long rural' or CBD feeder classification and information is therefore not provided. Calculations are completed in accordance with AER definitions. The average distribution customer numbers used in calculations is taken from RIN 1a Table 4.

Appendix D: United Energy Statutory Accounts

Note: See attached

United Energy Distribution Pty Ltd

ABN 70 064 651 029

Annual Financial Report
for the year ended 31 December 2014

Directors	Mr Peter Lowe *Chairman and Non-Executive Director*
	Mr David Bartholomew *Non-Executive Director*
	Mr Jason Conroy *Non-Executive Director*
	Mr Geoffrey Nicholson *Non-Executive Director*
	Ms Joanne Pearson *Alternate Director (alternate to Mr Geoffrey Nicholson)*
	Mr Nicholas Kuys *Alternate Director (alternate to Mr David Bartholomew & Mr Jason Conroy, appointed 30 August 2013)*
Secretary	Mr Robert Sarafian
Principal registered office in Australia	Level 3 6 Nexus Court Mulgrave Victoria 3170 Australia Phone: +61 3 8846 9900
Auditor	Ernst & Young Ernst & Young Building 8 Exhibition Street Melbourne 3000
Principle activity	The distribution of electricity and the construction and maintenance of electricity networks in Victoria, Australia.
Country of incorporation	Australia
Domicile	Australia
Group functional and presentation currency	Australia dollar (A$)
Legal form	Proprietary company limited by shares
Website	www.uemg.com.au

Directors' report

Your directors present their report on the consolidated entity (referred to hereafter as the Group) consisting of United Energy Distribution Pty Ltd and the entities it controlled at the end of, or during, the year ended 31 December 2014.

Directors
Mr Peter Lowe
Chairman and Non-Executive Director

Mr David Bartholomew
Non-Executive Director

Mr Jason Conroy
Non-Executive Director

Mr Geoffrey Nicholson
Non-Executive Director

Ms Joanne Pearson
Alternate Director (alternate to Mr Geoffrey Nicholson)

Mr Nicholas Kuys
Alternate Director (alternate to Mr David Bartholomew & Mr Jason Conroy, appointed 30 August 2013)

Principal activities
During the period the principal continuing activities of the Group consisted of the distribution of electricity and the construction and maintenance of its electricity network in Victoria, Australia.

No significant changes in the nature of these activities occurred during the year.

Dividends
No dividends were declared or paid during the year ended 31 December 2014 (2013: nil).

Review of operations
The review of operations covers the year from 1 January 2014 to 31 December 2014.

The profit from ordinary activities after income tax amounted to $904,000 (2013: $23,374,000).

Consolidated revenue for the period was $624,232,000 (2013: $604,385,000). Of this figure, electricity distribution revenue amounted to $499,181,000 (2013: $468,434,000). The network distributed 7,856 GWh (2013: 8,121 GWh) of electricity during the year.

As at 31 December 2014, the Group has a net current asset deficiency of $39,175,000. The main driver of the deficiency is due to derivative financial instruments. Despite this deficiency the Group expects to meet its obligations as they fall due on the basis that the Group can continue to generate positive operating cashflows and/or has sufficient appropriate debt and equity capital in place to enable operations to continue as a going concern.

Matters subsequent to the end of the financial year
No matter or circumstance has arisen since 31 December 2014 that has significantly affected, or may significantly affect:

(a) the Group's operations in future financial years, or
(b) the results of those operations in future financial years, or
(c) the Group's state of affairs in future financial years.

Likely developments and expected results of operations
The consolidated entity will continue its policy of providing safe and reliable electricity distribution services.

At the date of this report, there are no likely developments in the operations of the consolidated entity that, in the opinion of the directors, are likely to significantly impact the consolidated entity in the future.

Environmental regulation
The consolidated entity's operations are subject to significant environmental regulation under the Environmental Protection Act 1970 (Vic). The consolidated entity embraces environmental management principles using compliance with ISO 14001 for proactive planning, sustainable development and self assessment for continuous improvement. The consolidated entity did not receive any notification from the Environmental Protection Agency (EPA) for violation of the Act for the current or previous period and up to the date of signing this report in 2013.

Auditor's independence declaration
A copy of the auditor's independence declaration as required under section 307C of the *Corporations Act 2001* is set out on page 4.

Rounding of amounts
The company is of a kind referred to in Class Order 98/100, issued by the Australian Securities and Investments Commission, relating to the 'rounding off' of amounts in the directors' report. Amounts in the directors' report have been rounded off in accordance with that Class Order to the nearest thousand dollars, or in certain cases, to the nearest dollar.

Mr Peter Lowe
Director

Melbourne

{The Auditor's Independence Declaration will be provided by your Auditor.}

United Energy Distribution Pty Ltd ABN 70 064 651 029
Annual Financial Report - 31 December 2014

Contents

United Energy Distribution Pty Ltd
Consolidated income statement
For the year ended 31 December 2014

	Notes	**Consolidated entity Year ended 31 December 2014 $'000**	31 December 2013 $'000
Revenue from continuing operations			
Revenue	4	**624,232**	604,385
Expenses			
Loss on retirement of property, plant and equipment		**(2,146)**	(4,520)
Grid fees		**(109,583)**	(106,371)
Jurisdictional Scheme expenses		**(17,703)**	(19,137)
Operating fees		**(65,412)**	(76,957)
IT expenses		**(20,711)**	(21,067)
Other expenses		**(25,957)**	(31,336)
Depreciation and amortisation expense	5	**(134,650)**	(138,257)
Employee expenses		**(24,957)**	(18,077)
Consulting expenses		**(20,189)**	(12,210)
Unrealised foreign exchange gain/loss		**139**	1,543
Finance costs	5	**(204,066)**	(146,900)
Total expenses		**(625,235)**	(573,289)
Profit before income tax		**(1,003)**	31,096
Income tax expense	6	**1,907**	(7,722)
Profit for the period		**904**	23,374
Profit is attributable to:			
Owners of United Energy Distribution Pty Ltd		**904**	23,374

The above consolidated income statement should be read in conjunction with the accompanying notes.

United Energy Distribution Pty Ltd
Consolidated statement of comprehensive income
For the year ended 31 December 2014

	Notes	**Consolidated entity Year ended 31 December 2014 $'000**	31 December 2013 $'000
Profit for the period		**904**	23,374
Other comprehensive income			
Items that may reclassified to profit or loss			
Changes in the fair value of cash flow hedges	23(a)	**38,612**	(3,763)
Income tax on changes in the fair value of cash flow hedge		**(11,584)**	1,129
Other comprehensive income for the period, net of tax		**27,028**	(2,634)
Total comprehensive income for the period		**27,932**	20,740
Total comprehensive income for the period is attributable to:			
Owners of United Energy Distribution Pty Ltd		**27,932**	20,740
Total comprehensive income for the period attributable to owners of United Energy Distribution Pty Ltd arises from:			
Continuing operations		**27,932**	20,740

The above consolidated statement of comprehensive income should be read in conjunction with the accompanying notes.

	Notes	Consolidated entity **31 December 2014 $'000**	 31 December 2013 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	**22,208**	204,787
Trade and other receivables	8	**3,747**	19,147
Inventories	9	**6,361**	5,833
Derivative financial instruments	11	**7,863**	5,436
Other current assets	10	**83,459**	61,082
Total current assets		**123,638**	296,285
Non-current assets			
Receivables	12	**1,335,064**	1,320,256
Derivative financial instruments	11	**75,339**	38,535
Property, plant and equipment	13	**2,003,523**	1,875,924
Deferred tax assets	15	**40,536**	45,154
Intangible assets	14	**476,941**	485,937
Total non-current assets		**3,931,403**	3,765,806
Total assets		**4,055,041**	4,062,091
LIABILITIES			
Current liabilities			
Trade and other payables	16	**124,176**	120,222
Borrowings	17	**-**	672,782
Derivative financial instruments	11	**32,497**	28,314
Provisions	18	**6,140**	4,795
Total current liabilities		**162,813**	826,113
Non-current liabilities			
Borrowings	19	**2,338,888**	1,691,627
Derivative financial instruments	11	**40,151**	80,681
Deferred tax liabilities	20	**116,354**	94,551
Provisions	18	**2,878**	2,878
Other non-current liabilities	21	**167,300**	167,514
Total non-current liabilities		**2,665,571**	2,037,251
Total liabilities		**2,828,384**	2,863,364
Net assets		**1,226,657**	1,198,727
EQUITY			
Contributed equity		**646,459**	646,459
Other reserves	23(a)	**(18,573)**	(45,601)
Retained earnings	23(b)	**598,771**	597,869
Total equity		**1,226,657**	1,198,727

The above consolidated balance sheet should be read in conjunction with the accompanying notes.

United Energy Distribution Pty Ltd
Consolidated statement of changes in equity
For the year ended 31 December 2014

	Attributable to owners of United Energy Distribution Pty Ltd				
Consolidated entity	**Contributed equity $'000**	**Reserves $'000**	**Retained earnings $'000**	**Total $'000**	**Total equity $'000**
Balance at 1 January 2013	646,459	(42,967)	574,495	1,177,987	1,177,987
Profit for the year	-	-	23,374	23,374	23,374
Total comprehensive income for the period	**-**	**-**	**23,374**	**23,374**	**23,374**
Transactions with owners in their capacity as owners:					
Effective portion of changes in cash flow hedge, net of tax	-	(2,634)	-	(2,634)	(2,634)
Balance at 31 December 2013	**646,459**	**(45,601)**	**597,869**	**1,198,727**	**1,198,727**
Balance at 1 January 2014	646,459	(45,601)	597,869	1,198,727	1,198,727
Profit for the year	-	-	902	902	902
Total comprehensive income for the period	**-**	**-**	**902**	**902**	**902**
Transactions with owners in their capacity as owners:					
Effective portion of changes in cash flow hedge, net of tax	-	27,028	-	27,028	27,028
Balance at 31 December 2014	**646,459**	**(18,573)**	**598,771**	**1,226,657**	**1,226,657**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

	Notes	**Consolidated entity Year ended 31 December 2014 $'000**	31 December 2013 $'000
Cash flows from operating activities			
Receipts from customers (inclusive of goods and services tax)		**651,615**	648,808
Payments to suppliers and employees (inclusive of goods and services tax)		**(349,049)**	(353,828)
Interest received		**4,355**	4,784
Finance costs paid		**(195,331)**	(170,856)
Income tax refunded		**34,395**	9,076
		145,985	137,984
Net cash inflow from operating activities	28	**145,985**	137,984
Cash flows from investing activities			
Payments for property, plant and equipment	13	**(206,631)**	(239,416)
Proceeds from sale of property, plant and equipment		**1,586**	815
Payment for intangibles		**(34,976)**	(22,214)
Net cash (outflow) from investing activities		**(240,021)**	(260,815)
Cash flows from financing activities			
Net external borrowings		**(88,543)**	316,000
Net cash (outflow) inflow from financing activities		**(88,543)**	316,000
Net (decrease) increase in cash and cash equivalents		**(182,579)**	193,169
Cash and cash equivalents at the beginning of the financial year		**204,787**	11,618
Cash and cash equivalents at end of period	7	**22,208**	204,787

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

Contents of the notes to the consolidated financial statements

1 Summary of significant accounting policies

The principal accounting policies adopted in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all the periods presented, unless otherwise stated. The financial statements are for the consolidated entity consisting of United Energy Distribution Pty Ltd and its subsidiaries.

(a) Financial reporting framework

exist who are unable to command the preparation of reports tailored so as to satisfy specifically all of their information needs. Accordingly, this 'special purpose financial report' has been prepared to satisfy the directors' regulatory reporting
requirements.

The financial report has been prepared in accordance with the basis of accounting and disclosure requirements specified by all Accounting Standards and Interpretations, except the disclosure requirements of the pronouncements listed below.
Accounting Standards include Australian equivalents to International Financial Reporting Standards ('AIFRS').

AASB 7: Financial Instruments: Disclosures
AASB 112: Income Taxes
AASB 114: Segment Reporting
AASB 116: Property, Plant and Equipment
AASB 119: Employee Benefits
AASB 124: Related Party Disclosures
AASB 137: Provisions, Contingent Liabilities and Contingent Assets
AASB 138: Intangible Assets

(b) Basis of preparation

As at 31 December 2014, the Group has a net current asset deficiency of $39,175,000. The main driver of the deficiency is due to derivative financial instuments. Despite this deficiency the Group expects to meet its obligations as they fall due on the basis that the Group can continue to generate positive operating cashflows and/or has sufficient appropriate debt and equity capital in place to enable operations to continue as a going concern.

(i) Historical cost convention
These financial statements have been prepared under the historical cost convention, as modified by the revaluation of available-for-sale financial assets, financial assets and liabilities (including derivative instruments) at fair value through profit or loss, certain classes of property, plant and equipment and investment property.

(ii) Critical accounting estimates
The preparation of financial statements requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the financial statements, are disclosed in note 3.

1 Summary of significant accounting policies (continued)

(b) Basis of preparation (continued)

(ii) Critical accounting estimates (continued)
The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstance, the results of which form the basis of making the judgments. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Judgments made by management in the application of the Group's accounting policies that have significant effects on the financial statements and estimates with a significant risk of material adjustments in the next year are disclosed, where applicable, in the relevant notes to the financial statements.

Accounting policies are selected and applied in a manner which ensures that the resulting financial information satisfies the concepts of relevance and reliability, thereby ensuring that the substance of the underlying transactions or other events are reported.

(c) Principles of consolidation

(i) Subsidiaries
The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of United Energy Distribution Pty Ltd ('company' or 'parent entity') as at 31 December 2014 and the results of all subsidiaries for the period then ended. United Energy Distribution Pty Ltd and its subsidiaries together are referred to in this financial report as the Group or the consolidated entity.

Controlled entities are all entities (including special purpose entities) over which the Group has the power to govern the financial and operating policies, generally accompanying a shareholding of more than one-half of the voting rights. The existence and effect of potential voting rights that are currently exercisable or convertible are considered when assessing whether the Group controls another entity.

Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are de-consolidated from the date that control ceases.

Intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of the impairment of the asset transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

The effect of all transactions between entities in the consolidated entity are eliminated in full.

(d) Foreign currency translation

(i) Functional and presentation currency
Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates ('the functional currency'). The consolidated financial statements are presented in Australian dollars, which is United Energy Distribution Pty Ltd's functional and presentation currency.

(ii) Transactions and balances
Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss, except when they are deferred in equity as qualifying cash flow hedges and qualifying net investment hedges or are attributable to part of the net investment in a foreign operation.

1 Summary of significant accounting policies (continued)

(d) Foreign currency translation (continued)

(iii) Specific commitments: hedging
Hedging is undertaken in order to avoid or minimise possible adverse financial effects of movements in exchange rates.

Borrowings that are denominated in foreign currencies that are fully hedged have been converted to Australian currency, using rates of exchange ruling at the end of the financial year, and the related hedge asset or liability is calculated using the hedge rates.

(e) Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable. Amounts disclosed as revenue are net of returns, trade allowances, rebates and amounts collected on behalf of third parties.

Revenue is recognised for the major business activities as follows:

(i) Distribution of electricity revenue
Distribution of electricity revenue earned from the use of the distribution network is recognised when electricity and related services are provided. Accrued distribution of electricity revenue is determined having regard to the period since a customer's last billing date and the customer's previous consumption patterns. Distribution of electricity revenue includes the cost of transmission services charged by the transmission companies, which is passed on to the customers.

(ii) Customer contributions
Non-refundable contributions and in kind assets received from customers towards the cost of extending or modifying the electricity distribution network, whether on existing or new assets, are recognised as revenue and an asset once control is gained of the contribution or asset.

(iii) Interest revenue
Interest revenue is recognised to the extent that it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured. Interest income is brought to account on an accruals basis using the effective interest method.

(iv) Other revenue
Other revenue is brought to account as it is earned and is recognised when the goods and services are provided.

(f) Finance costs

Finance costs include interest and ancillary costs incurred in connection with arrangements of borrowings.

Finance costs are expensed during the period in which they are incurred. Borrowing costs incurred for the construction of any qualifying asset are not capitalised during the period of time that is required to complete and prepare the asset for its intended use or sale.

Long term borrowings are initially recognised at fair value, net of finance costs incurred. The differences between the proceeds (net of finance costs) and the redemption value is recognised in the income statement over the period of the borrowings using the effective interest rate.

1 Summary of significant accounting policies (continued)

(g) Income tax

Income tax on the profit or loss for the year comprises current and deferred tax. Income tax is recognised in the income statement except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

Current income tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the balance date, and any adjustment to tax payable in respect of previous years. Deferred tax is provided using the balance sheet liability method, providing for temporary differences between carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. The following temporary differences are not provided for: goodwill not deductible for tax purposes; the initial recognition of assets and liabilities that affect neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they will probably not reverse in the foreseeable future. The amount of deferred tax provided is based on the expected manner of realisation or settlement of the carrying amount of assets and liabilities using tax rates enacted or substantially enacted at the balance date.

A deferred tax asset is recognised only to the extent that it is probable that future tax profits will be available against which the asset can be utilised. Deferred tax assets are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

(i) Tax consolidation

United Energy Distribution Holdings Pty Ltd is the head company in a tax consolidated group ("Group") comprising it and its Australian wholly-owned subsidiaries of which United Energy Distribution Pty Ltd is a member. The implementation date for this Group was 23 July 2003.

Current tax expense/benefit, deferred tax liabilities and deferred tax assets arising from temporary differences of the members of the tax consolidated group are recognised in the separate financial statements of the members of the tax consolidated group using the "group allocation" approach by reference to the carrying amounts at the tax consolidated group level and their tax values as applicable under the tax consolidation legislation.

Any current tax liabilities (or assets) and deferred tax assets arising from unused tax losses of the subsidiary is assumed by the head entity in the tax consolidated group and are recognised as amounts payable/(receivable) to/(from) other entities in the tax consolidated group in conjunction with any tax funding agreement amounts (refer below).

The tax consolidated group has entered into a tax funding agreement that requires the wholly owned subsidiary to make contributions to the head entity for current tax assets and liabilities arising from external transactions occurring after the implementation of tax consolidation. The contribution is recorded as an intercompany receivable/payable.

Under the tax funding agreement, the contributions are calculated on a "group allocation basis" so that the contributions are equivalent to the tax balances generated by external transactions entered into by the wholly owned subsidiary. The contributions are payable as set out in the agreement and reflect the timing of the head entity's obligations to make payments for tax liabilities to the relevant tax authorities. The assets and liabilities arising under tax funding agreements are recognised as intercompany assets and liabilities with a consequential adjustment to income tax expense/revenue.

1 Summary of significant accounting policies (continued)

(h) Impairment of assets

(i) Financial assets
A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortised cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate.

An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its current fair value.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognised in profit or loss. Any cumulative loss in respect of an available-for-sale financial asset recognised previously in equity is transferred to profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognised. For financial assets measured at amortised cost and available-for-sale financial assets that are debt securities, the reversal is recognised in profit or loss. For available-for-sale financial assets that are equity securities, the reversal is recognised directly in equity.

(ii) Non-financial assets
The carrying amounts of the consolidated entity's non-financial assets, other than inventories and deferred tax assets, are reviewed bi-annually to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated.

For assets that have an indefinite useful life, the recoverable amount is estimated bi-annually. An impairment loss is recognised whenever the carrying amount of an asset or its cash generating unit exceeds its recoverable amount. Impairment losses are recognised in the income statement. Impairment losses recognised in respect of cash generating units are allocated to reduce the carrying amount of assets in the cash generating unit (group of units) on a pro rata basis.

The recoverable amount of an asset or cash generating unit is the greater of their fair value less costs to sell and value in use. In assessing value in use, the assets of the consolidated entity are assessed as one class of assets in their entirety.

The estimated future cash flows are discounted to their present value using a pre tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For an asset that does not generate largely independent cash inflows the recoverable amount is determined for the cash generating unit to which the asset belongs.

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation, if no impairment loss has been recognised.

(i) Cash and cash equivalents

For the purpose of presentation in the consolidated statement of cash flows, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts are shown within borrowings in current liabilities in the consolidated balance sheet.

1 Summary of significant accounting policies (continued)

(j) Trade receivables

Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment. Trade receivables are generally due for settlement within 30 days. They are presented as current assets unless collection is not expected for more than 12 months after the reporting date.

Collectibility of trade debtors is reviewed on an ongoing basis. Debts which are known to be uncollectible are written off. A provision is raised for any doubtful accounts. A provision for impairment of trade receivables is established when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables. The amount of the provision is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. Cash flows relating to short-term receivables are not discounted if the effect of discounting is immaterial. The amount of the provision is recognised in the income statement in other expenses.

(k) Inventories

Transformers and meters are stated at the lower of cost and net realisable value. Cost is measured at actual cost and provision is made for obsolescence where applicable.

(l) Derivatives and hedging activities

Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently remeasured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The Group designates certain derivatives as either:

- hedges of the fair value of recognised assets or liabilities or a firm commitment (fair value hedges)
- hedges of a particular risk associated with the cash flows of recognised assets and liabilities and highly probable forecast transactions (cash flow hedges), or
- hedges of a net investment in a foreign operation (net investment hedges).

The Group documents at the inception of the hedging transaction the relationship between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. The Group also documents its assessment, both at hedge inception and on an ongoing basis, of whether the derivatives that are used in hedging transactions have been and will continue to be highly effective in offsetting changes in fair values or cash flows of hedged items.

The fair values of various derivative financial instruments used for hedging purposes are disclosed in note 11. Movements in the hedging reserve in shareholder's equity are shown in note 23. The full fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than 12 months; it is classified as a current asset or liability when the remaining maturity of the hedged item is less than 12 months. Trading derivatives are classified as a current asset or liability.

(i) Fair value hedge

Changes in the fair value of derivatives that are designated and qualify as fair value hedges are recorded in profit or loss, together with any changes in the fair value of the hedged asset or liability that are attributable to the hedged risk. The gain or loss relating to the effective portion of interest rate swaps hedging fixed rate borrowings is recognised in profit or loss within finance costs, together with changes in the fair value of the hedged fixed rate borrowings attributable to interest rate risk. The gain or loss relating to the ineffective portion is recognised in profit or loss within other income or other expenses.

If the hedge no longer meets the criteria for hedge accounting, the adjustment to the carrying amount of a hedged item for which the effective interest method is used is amortised to profit or loss over the period to maturity using a recalculated effective interest rate.

1 Summary of significant accounting policies (continued)

(l) Derivatives and hedging activities (continued)

(ii) Cash flow hedge
The effective portion of changes in the fair value of derivatives that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated in reserves in equity. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss within other income or other expenses.

Amounts accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss (for instance when the forecast sale that is hedged takes place). The gain or loss relating to the effective portion of interest rate swaps hedging variable rate borrowings is recognised in profit or loss within 'finance costs'. The gain or loss relating to the effective portion of forward foreign exchange contracts hedging export sales is recognised in profit or loss within 'sales'. However, when the forecast transaction that is hedged results in the recognition of a non-financial asset (for example, inventory or fixed assets) the gains and losses previously deferred in equity are reclassified from equity and included in the initial measurement of the cost of the asset. The deferred amounts are ultimately recognised in profit or loss as cost of goods sold in the case of inventory, or as depreciation or impairment in the case of fixed assets.

When a hedging instrument expires or is sold or terminated, or when a hedge no longer meets the criteria for hedge accounting, any cumulative gain or loss existing in equity at that time remains in equity and is recognised when the forecast transaction is ultimately recognised in profit or loss. When a forecast transaction is no longer expected to occur, the cumulative gain or loss that was reported in equity is immediately reclassified to profit or loss.

(m) Property, plant and equipment

Land and buildings are shown at fair value, less subsequent depreciation for buildings. Any accumulated depreciation at the date of revaluation is eliminated against the gross carrying amount of the asset and the net amount is restated to the revalued amount of the asset. All other property, plant and equipment is stated at historical cost less depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Cost may also include transfers from equity of any gains or losses on qualifying cash flow hedges of foreign currency purchases of property, plant and equipment.

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of any component accounted for as a separate asset is derecognised when replaced. All other repairs and maintenance are charged to profit or loss during the reporting period in which they are incurred.

Land is not depreciated. Depreciation on other assets is calculated using the straight-line method to allocate their cost or revalued amounts, net of their residual values, over their estimated useful lives or, in the case of leasehold improvements and certain leased plant and equipment, the shorter lease term as follows:

- Buildings	10 - 40 years
- Plant and equipment	15 - 50 years
- Vehicles	5 - 10 years
- Office equipment	3 - 15 years
- Furniture, fixtures and fittings	1 - 12 years

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at the end of each reporting period.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount (note 1(h)).

Gains and losses on disposals are determined by comparing proceeds with carrying amount. These are included in profit or loss. When revalued assets are sold, it is Group policy to transfer any amounts included in other reserves in respect of those assets to retained earnings.

1 Summary of significant accounting policies (continued)

(n) Intangible assets

(i) Distribution licences

The consolidated entity has a licence that entitles it to distribute electricity within its region. The licence has been brought to account having regard to the expected future net cash flows derived from holding the licence. No amortisation is provided, since in the opinion of the directors, the life of the licence is of such duration, and the residual value would be such that the amortisation charge, if any, would not be material. To support the ongoing carrying value of this asset, nothing has occurred to suggest the terms and conditions of the issuance of the licence have not been complied with. The value of this licence is reviewed annually.

(ii) Software licences

When the software is not an integral part of the related hardware, it is treated as an intangible asset. All software licences are recorded at cost and amortised on a straight line basis over their useful lives, which range from 4 to 5 years.

(o) Trade and other payables

These amounts represent liabilities for goods and services provided to the Group prior to the end of financial year which are unpaid. The amounts are unsecured and are usually paid within 30 days of recognition. Trade and other payables are presented as current liabilities unless payment is not due within 12 months from the reporting date. They are recognised initially at their fair value and subsequently measured at amortised cost using the effective interest method.

(p) Customer deposit

Customer deposits are recognised as liabilities and represent either refundable deposits that are received in advance as finance on capital projects or advances from customers held as security over future electricity usage.

(q) Interest bearing liabilities

Borrowings are initially recognised at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortised cost. Any difference between the proceeds (net of transaction costs) and the redemption amount is recognised in profit or loss over the period of the borrowings using the effective interest method. Fees paid on the establishment of loan facilities are recognised as transaction costs of the loan to the extent that it is probable that some or all of the facility will be drawn down. In this case, the fee is deferred until the draw down occurs. To the extent there is no evidence that it is probable that some or all of the facility will be drawn down, the fee is capitalised as a prepayment for liquidity services and amortised over the period of the facility to which it relates.

Preference shares, which are mandatorily redeemable on a specific date, are classified as liabilities. The dividends on these preference shares are recognised in profit or loss as finance costs.

Borrowings are removed from the balance sheet when the obligation specified in the contract is discharged, cancelled or expired. The difference between the carrying amount of a financial liability that has been extinguished or transferred to another party and the consideration paid, including any non-cash assets transferred or liabilities assumed, is recognised in profit or loss as other income or finance costs.

Where the terms of a financial liability are renegotiated and the entity issues equity instruments to a creditor to extinguish all or part of the liability (debt for equity swap), a gain or loss is recognised in profit or loss, which is measured as the difference between the carrying amount of the financial liability and the fair value of the equity instruments issued.

Borrowings are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least 12 months after the reporting period.

1 Summary of significant accounting policies (continued)

(r) Provisions

Provisions for legal and other claims are recognised when the Group has a present obligation (legal or constructive) as a result of past event, it is probable that the Group will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. Provisions are not recognised for future operating losses.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the reporting date, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cashflows estimated to settle the present obligation, its carrying amount is the present value of those cashflows.

(i) Environmental provision
Provision has been made in the financial statements for environmental management costs to ensure compliance with environmental management principles using ISO 14001 and The Environment Protection Act 1970 of Victoria.

(s) Employee benefits

(i) Wages and salaries, annual leave and sick leave
Liabilities for wages and salaries, including non-monetary benefits, annual leave and accumulating sick leave expected to be settled within 12 months of the reporting date are measured at the amounts expected to be paid when the liabilities are settled. Liabilities for non-accumulating sick leave are recognised when the leave is taken and measured at the rates paid or payable.

(ii) Long service leave
The liability for long service leave expected to be settled in twelve months of the balance date is recognised in the provision for employee benefits and is measured in accordance with (i) above. The liability for long service leave is recognised in the provision for employee benefits and measured as the present value of expected future payments to be made in respect of services provided by employees up to the reporting date. Consideration is given to expected future wage and salary levels, experience of employee departures and periods of service. Expected future payments are discounted using market yields at the reporting date on national government bonds with terms to maturity and currency that match, as closely as possible, the estimated future cash outflows.

The annual leave, long service leave and any outstanding wages and salaries entitlements are grouped together as employee benefits in the accounts. These benefits are also analysed between current and non-current depend on when they are due and payable.

(t) Contributed equity

Contributed equity is recorded at consideration received. The costs of issuing securities are charged against contributedequity. The terms and conditions of various classes of equities affecting income or capital entitlements are detailed in note 22.

(u) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of associated GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense.

Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the consolidated balance sheet.

1 Summary of significant accounting policies (continued)

(u) Goods and Services Tax (GST) (continued)

Cash flows are presented on a gross basis. The GST components of cash flows arising from investing or financing activities which are recoverable from, or payable to the taxation authority, are presented as operating cash flows.

(v) Rounding of amounts

The company is of a kind referred to in Class Order 98/100, issued by the Australian Securities and Investments Commission, relating to the 'rounding off' of amounts in the financial statements. Amounts in the financial statements have been rounded off in accordance with that Class Order to the nearest thousand dollars, or in certain cases, the nearest dollar.

(w) Comparative figures

When required by Accounting standards, comparative figures have been adjusted to conform to changes in presentation for the current financial period.

2 Financial risk management

(a) Market risk

(i) Foreign exchange risk
Foreign exchange risk arises when future commercial transactions and recognised assets and liabilities are denominated in a currency that is not the entity’s functional currency.

The Group operates within Australia and is only exposed to foreign exchange risk arising from currency exposures to the US dollar on borrowings and equipment purchase.

Cross currency swaps are used to manage foreign exchange risk associated with the US dollar borrowings.

The Group’s risk management policy is to hedge 100% of all foreign exchange transactions for the life of the transaction.

2 Financial risk management (continued)

(b) Interest rate risk

As the Group has no significant interest-bearing assets, the Group's income and operating cash flows are not materially exposed to changes in market interest rates although revenues are linked to CPI. The Group does not hedge revenues but structures a portion of its interest rate hedging to take this into account.

The Group's interest-rate risk arises from long-term borrowings. Borrowings issued at variable rates expose the Group to cash flow interest-rate risk. Group policy is to fix the rates for between 80% and 100% of its borrowings within the regulatory period.

The Group manages its cash flow interest-rate risk by using floating-to-fixed interest rate swaps. Borrowings issued at fixed rates expose the Group to fair value interest-rate risk. Such interest rate swaps have the economic effect of converting borrowings from floating rates to fixed rates. Generally, the Group raises long-term borrowings at floating rates and swaps them into fixed rates that are lower than those available if the Group borrowed them at fixed rates directly.

Under the interest-rate swaps, the Group agrees with other parties to exchange, at specified intervals (mainly quarterly), the difference between fixed contract rates and floating-rate interest amounts calculated by reference to the agreed notional principal amounts.

(c) Credit risk

The Group has no significant concentrations of credit risk. The Group has policies in place to ensure that sales of products and services are made to customers with an appropriate credit history. Derivative counterparties and cash transactions are limited to high credit quality financial institutions. The Group has policies that limit the amount of credit exposure to any one financial institution.

(d) Liquidity risk

Prudent liquidity risk management implies maintaining sufficient cash and marketable securities, the availability of funding through an adequate amount of committed credit facilities and the ability to close out market positions. Due to the dynamic nature of the underlying businesses, AMPCI aims at maintaining flexibility in funding by keeping committed credit lines available.

3 Critical accounting estimates and judgements

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that may have a financial impact on the entity and that are believed to be reasonable under the circumstances.

(a) Critical accounting estimates and assumptions

The Group makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

3 Critical accounting estimates and judgements (continued)

(a) Critical accounting estimates and assumptions (continued)

(i) Impairment of assets
Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation and are tested bi-annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value-in-use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Non-financial assets other than goodwill that suffered an impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

(ii) Provisions
The Group calculates the carrying amount of provisions under AASB 137 based on a variety of available information, much of which is based on estimates of the likely outflow of economic benefits.

(iii) Income taxes
The Group applies the criteria stated in AASB 112 with regards to the calculation and recognition of deferred tax assets and liabilities. The application of the AASB 112 criteria involves the exercise of judgment surrounding the calculation of accounting and tax bases for the Group’s assets and liabilities. Furthermore, the potential reversal of temporary differences also requires the use of estimates of future profitability, availability of taxable profits/losses on both revenue and capital account and potential future changes in accounting and tax bases.

In particular, the expectation of the availability of future taxable profits against which deferred tax assets arising in respect of revenue losses is subject to estimation and judgment.

(b) Critical judgements in applying the entity's accounting policies

At balance date the Group had not made any significant judgements in applying accounting policies that it considers critical to the Group's results.

4 Revenue

	Consolidated entity Year ended	
	31 December 2014 $'000	31 December 2013 $'000
From continuing operations		
Distribution revenue	**499,181**	468,434
Other services	**121,314**	125,444
Miscellaneous revenue	**599**	4,901
Foreign exchange (loss) / gains	**(63)**	(333)
	621,031	598,446
Other revenue		
Interest - external	**3,201**	5,939
	624,232	604,385

5 Expenses

	Consolidated entity Year ended	
	31 December 2014 $'000	31 December 2013 $'000
Profit before income tax includes the following specific expenses:		
Depreciation		
Buildings	**325**	212
Plant and equipment	**90,354**	97,103
Total depreciation	**90,679**	97,315
Amortisation		
Software	**29,050**	27,959
Deferred expenditure	**14,921**	12,983
Total amortisation	**43,971**	40,942
Total depreciation and amortisation	**134,650**	138,257
Finance costs		
Related parties	**38,994**	38,887
Other corporations	**165,072**	108,013
	204,066	146,900

6 Income tax expense

(a) Income tax expense

	Consolidated entity Year ended 31 December 2014 $'000	31 December 2013 $'000
Current tax	**(1,907)**	(9,077)
Deferred tax	**14,836**	16,799
	12,929	7,722
Income tax expense is attributable to:		
Profit from continuing operations	**(1,907)**	7,722
Deferred income tax expense included in income tax expense comprises:		
(Increase) decrease in deferred tax assets (note 15)	**(6,967)**	23,026
(Decrease) increase in deferred tax liabilities (note 20)	**21,803**	(6,227)
	14,836	16,799

(ii) Tax consolidation legislation
Effective 23 July 2003, for the purposes of income taxation, United Energy Distribution Holdings Pty Ltd and its 100% Australian owned subsidiaries, of which United Energy Distribution Pty Ltd is a member, formed a tax consolidated group. Members of the Group entered into a tax sharing and tax funding arrangement in order to allocate income tax expense to the wholly-owned subsidiaries on a pro-rata basis. These arrangements have been updated to reflect UIG 1052. In addition, the agreement provides for the allocation of income tax liabilities between the entities should the head entity default on its tax payment obligations. At the balance date, the possibility of default is remote. The head entity of the tax consolidated group is United Energy Distribution Holdings Pty Ltd.

7 Current assets - Cash and cash equivalents

	Consolidated entity 31 December 2014 $'000	31 December 2013 $'000
Cash at bank and in hand	**22,162**	59,771
Other cash and cash equivalents	**46**	145,016
	22,208	204,787

(a) Terms and conditions

Cash is held at call and earns an average interest rate of 2.17% (2013: 2.67%) per annum.

8 Current assets - Trade and other receivables

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Trade receivables (a) (i)	**1,209**	15,077
Provision for impairment of receivables	**(1,410)**	(831)
	(201)	14,246
Interest receivables (a) (ii)	**3,948**	4,901
	3,747	19,147

(a) Terms and conditions

(i) Trade debtors are non-interest bearing and generally on 14 day terms.

(ii) Consolidated entity's interest receivable is on the following:
- USD leg of cross currency swaps - $3,948K

9 Current assets - Inventories

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Transformers	**3,215**	3,761
AMI meters	**3,146**	2,072
	6,361	5,833

10 Current assets - Other current assets

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Accrued revenue	**68,654**	48,012
Prepayment	**14,805**	13,070
	83,459	61,082

11 Derivative financial instruments

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Current assets		
Other hedging instruments	**7,863**	5,436
Total current derivative financial instrument assets	**7,863**	5,436
Non-current assets		
Other hedging instruments	**75,339**	38,535
Total non-current derivative financial instruments	**75,339**	38,535
Current liabilities		
Other hedging instruments	**(32,497)**	(28,314)
Total current derivative financial instrument liabilities	**(32,497)**	(28,314)
Non-current liabilities		
Other hedging instruments	**(40,151)**	(80,681)
Total non-current derivative financial instrument liabilities	**(40,151)**	(80,681)
	10,554	(65,024)

12 Non-current assets - Receivables

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Receivables from controlling entities	**1,335,064**	1,290,992
Other receivables	**-**	29,264
	1,335,064	1,320,256

12 Non-current assets - Receivables (continued)

(a) Receivables from contolling entities

A receivable of $1,267M from United Energy Distribution Holdings Pty Ltd has a maturity date of 23 July 2023. This is an interest free loan and has fair value equal to the nominal value because the borrower may repay the loan at any time.

Working capital arrangements amounting to $68M with related parties. These receivables are non-interest bearing and are generally settled on call.

13 Non-current assets - Property, plant and equipment

Consolidated entity	Freehold land $'000	Freehold buildings $'000	Plant and equipment $'000	In course of construction $'000	Total $'000
At 1 January 2013					
Cost or fair value	2,658	5,903	2,405,913	234,301	2,648,775
Accumulated depreciation	-	(3,335)	(914,075)	-	(917,410)
Net book amount	2,658	2,568	1,491,838	234,301	1,731,365
Year ended 31 December 2013					
Opening net book amount	2,658	2,568	1,491,838	234,301	1,731,365
Additions	-	30	156,036	91,457	247,523
Depreciation charge	-	(212)	(97,103)	-	(97,315)
Disposals - at cost	-	(550)	(13,680)	-	(14,230)
Disposals - accumulated depreciation	-	550	7,950	-	8,500
Transfers	-	-	137,511	(137,813)	(302)
Disposal others	-	-	383	-	383
Closing net book amount	2,658	2,386	1,682,935	187,945	1,875,924
At 31 December 2013					
Cost or fair value	2,658	5,384	2,691,269	187,945	2,887,256
Accumulated depreciation	-	(2,998)	(1,008,334)	-	(1,011,332)
Net book amount	2,658	2,386	1,682,935	187,945	1,875,924

13 Non-current assets - Property, plant and equipment (continued)

Year ended 31 December 2014					
Opening net book amount	2,658	2,386	1,682,935	187,945	1,875,924
Additions	-	636	172,446	49,576	222,658
Depreciation charge	-	(325)	(90,341)	-	(90,666)
Disposals - at cost	-	-	(11,367)	-	(11,367)
Disposals - accumulated depreciation	-	-	7,635	-	7,635
Transfers	-	2,001	77,473	(80,135)	(661)
Closing net book amount	2,658	4,698	1,838,781	157,386	2,003,523
At 31 December 2014					
Cost	2,658	8,021	2,933,817	157,386	3,101,882
Accumulated depreciation	-	(3,323)	(1,095,036)	-	(1,098,359)
Net book amount	2,658	4,698	1,838,781	157,386	2,003,523

14 Non-current assets - Intangible assets

Consolidated entity	**Software $'000**	**AMI intangibles $'000**	**Licence $'000**	**Total $'000**
At 1 January 2013				
Cost	225,333	77,347	357,200	659,880
Accumulation amortisation and impairment	(127,323)	(27,891)	-	(155,214)
Net book amount	98,010	49,456	357,200	504,666
Year ended 31 December 2013				
Opening net book amount	98,010	49,456	357,200	504,666
Additions - acquisition	9,793	12,119	-	21,912
Amortisation charge	(27,959)	(12,983)	-	(40,942)
Transfers	1,829	(1,528)	-	301
Disposals -costs	(22,675)	-	-	(22,675)
Disposals - accumulated depreciation	22,675	-	-	22,675
Closing net book amount	81,673	47,064	357,200	485,937
Cost	214,409	87,938	357,200	659,547
Accumulation amortisation and impairment	(132,736)	(40,874)	-	(173,610)
Net book amount	81,673	47,064	357,200	485,937

14 Non-current assets - Intangible assets (continued)

Consolidated entity

Year ended 31 December 2014				
Opening net book amount	81,673	47,064	357,200	485,937
Additions - acquisition	23,007	11,309	-	34,316
Amortisation charge	(29,050)	(15,259)	-	(44,309)
Transfers	2,890	(1,893)	-	997
Closing net book amount	78,520	41,221	357,200	476,941
At 31 December 2014				
Cost	240,306	97,354	357,200	694,860
Accumulated amortisation	(161,786)	(56,133)	-	(217,919)
Net book amount	78,520	41,221	357,200	476,941

15 Non-current assets - Deferred tax assets

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Doubtful debts	**424**	249
Unrealised foreign exchange	**-**	202
Derivative financial instruments	**31,815**	33,167
Accrued revenue	**-**	2,684
Accident compensation	**35**	35
Environmental	**980**	980
Intellectual property	**4,157**	3,677
Other	**3,125**	4,160
	40,536	45,154

	Consolidated entity	
Movements:		
Opening balance	**45,152**	67,051
Charged/credited:		
- to profit or loss	**6,968**	(23,026)
- directly to equity	**(11,584)**	1,129
	40,536	45,154

16 Current liabilities - Trade and other payables

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Trade payables and accruals	**78,133**	81,602
Customer deposit	**13,776**	6,135
Accrued interest	**28,390**	27,844
Other payables	**-**	(2)
Payables to controlling entity	**3,680**	3,680
Goods and services tax (GST) (receivable)/ payable	**197**	963
	124,176	120,222

(a) Terms and conditions

(i) Trade payables and accruals
Trade payables and accruals are non-interest bearing and are normally settled on 30 day terms.

(ii) Accrued interest
Accrued interest payable is non-interest bearing and is settled in accordance with the terms and conditions of the related loan.

(iii) Payables to controlling entity
Debt raising costs regarding the stapled securities, payable to UEDH. Non-interest bearing with settlement being within 12 months.

17 Current liabilities - Borrowings

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Unsecured		
Bank loans	**-**	627,782
Working capital	**-**	45,000
Total unsecured current borrowings	**-**	672,782

18 Provisions

	Consolidated entity					
	31 December 2014			31 December 2013		
	Current $'000	**Non-current $'000**	**Total $'000**	Current $'000	Non-current $'000	Total $'000
Employee benefits	**115**	**-**	**115**	115	-	115
AMI rebate provision	**389**	**-**	**389**	-	-	-
Claims costs	**500**	**-**	**500**	-	-	-
Employee related provisions	**4,746**	**-**	**4,746**	4,290	-	4,290
Environmental provision	**390**	**2,878**	**3,268**	390	2,878	3,268
	6,140	**2,878**	**9,018**	4,795	2,878	7,673

(a) Employee related provisions

A provision has been created to reflect contributions required to be paid to UE & Multinet Pty Ltd if United Energy withdraws from the current cost sharing agreement.

(b) Environmental provision

Provision has been made in the financial statements for environmental management costs to ensure compliance with environmental management principles using ISO 14001 and *The Environment Protection Act 1970 (Vic)*.

19 Non-current liabilities - Borrowings

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Unsecured		
Subordinated loans from controlling entities (a)	**263,472**	263,472
Guaranteed notes (b)	**712,844**	650,580
Bank loans (c)	**1,103,500**	520,000
Loan notes	**264,660**	264,509
Deferred borrowing costs (d)	**(5,588)**	(6,934)
Total unsecured non-current borrowings	**2,338,888**	1,691,627

(a) Subordinated loans from controlling entities

A payable to Power Partnership Pty Ltd has a maturity date of 23 July 2023 and the interest rate is fixed at 14.8% per annum.

19 Non-current liabilities - Borrowings (continued)

(b) Guaranteed notes

A$195.6M (US$200M) 5.45% fixed rate guaranteed notes maturing on 15 April 2016, were issued on 19 November 2003.

UEDH raised funds through a US Private Placement in December 2010. Fixed Interest at 5.01% (USD$365M) for seven years, maturing 15 December 2017.

(c) Bank loans

The following loan facilities are unsecured:

Asian Debt - $400M (maturity: 24 April 2018), interest BBSY plus margin 1.90%.
Senior Corporate Facility Tranche A - $120M (maturity: 11 April 2018), interest BBSY plus margin 2.55%.
Capex Facility Tranche A - $76.5m (maturity: 20 May 2017), interest BBSY plus margin 1.25%.
Revolving Syndicated Facility - $305m (maturity: 20 May 2019), interest BBSY plus margin 1.50%.
WBC Bilateral Facility - $125m (maturity: 01 May 2018), interest BBSY plus margin 1.70%.
Revolving Syndicated Facility - $77m (maturity: 20 May 2019), interest BBSY plus margin 1.30%.

(d) Loan notes

A$265 million fixed rate notes at 6.25% maturing on 11 April 2017 were issued on 11 April 2012.

20 Non-current liabilities - Deferred tax liabilities

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
The balance comprises temporary differences attributable to:		
Intangible assets	**5,269**	5,118
Property, plant and equipment	**85,416**	63,369
Derivative financial instruments	**24,961**	22,331
Other	**708**	3,733
	116,354	94,551

	Consolidated entity	
Movements:		
Opening balance	**94,551**	100,778
Charged/credited:		
- profit or loss	**21,803**	(6,227)
	116,354	94,551

21 Non-current liabilities - Other non-current liabilities

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Payables to controlling entity	**167,300**	167,514
	167,300	167,514

(a) Terms and conditions

Accrued interest amounting to $167.5M is payable to Power Partnership Pty Ltd and is settled in accordance with the terms and conditions of the loan (refer note 19 NCL borrowings).

22 Contributed equity

(a) Share capital

	31 December 2014 Shares	31 December 2013 Shares	**31 December 2014 $'000**	31 December 2013 $'000
Ordinary shares				
Ordinary shares - fully paid	**421,770,972**	421,770,972	**452,644**	452,644
	421,770,972	421,770,972	**452,644**	452,644

There were no movements in ordinary shares during the year.

(b) Ordinary shares

Ordinary shares have the right to receive dividends as declared and, in the event of winding up the Company, to participate in the proceeds from the sale of all surplus assets in proportion to the number of and amounts paid up on shares held.

Ordinary shares entitle their holder to one vote, either in person or by proxy, at a meeting of the Company.

23 Other reserves and retained earnings

(a) Other reserves

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Cash flow hedges	**(18,573)**	(45,601)
	(18,573)	(45,601)

23 Other reserves and retained earnings (continued)

(a) Other reserves (continued)

Movements:

Cash flow hedges			
Opening balance		**(45,601)**	(42,967)
Revaluation - gross	11	**38,612**	(3,763)
Deferred tax	6, 15, 20	**(11,584)**	1,129
Balance 31 December		**(18,573)**	(45,601)

Hedge reserve - cash flow hedges

The hedge reserve is used to record gains or losses on a hedging instrument in a cash flow hedge that are recognised directly in equity, as described in note 12.

(b) Retained earnings

Movements in retained earnings were as follows:

	Consolidated entity	
	31 December 2014 $'000	31 December 2013 $'000
Balance 1 January	**597,867**	574,495
Net profit for the period	**3,317**	23,374
Balance 31 December	**601,184**	597,869

24 Remuneration of auditors

During the period the following fees were paid or payable for services provided by the auditor of the parent entity, its related practices and non-related audit firms:

(a) Ernst & Young

	Consolidated entity Year ended	
	2014 $	2013 $
Audit and other assurance services		
Audit and review of financial statements	**-**	307,500
Other assurance services		
Audit of regulatory returns	**-**	110,100
Other services	**-**	116,570
	-	226,670
Total remuneration for audit and other assurance services	**-**	534,170

25 Contingencies

The Group is subject to claims and other matters in the ordinary course of business. To the extent these matters are not provided in the financial report, the matters represent contingencies at 31 December 2014.

The Group had no material contingent liabilities or assets at 31 December 2014 (2013: nil).

26 Investments in associates

Investments in associates are accounted for in the consolidated financial report using the equity method of accounting and are carried at cost by the parent entity. Information relating to the associates is set out below.

	Company's share of:	
	2014	2013
	%	%
UE & Multinet Pty Ltd (formerly Energy Retail Holdings Pty Ltd)	**50**	50

27 Investments in controlled entities

The consolidated financial statements incorporate the assets, liabilities and results of the following controlled entities in accordance with the accounting policy described in note 3:

Name of entity	**Country of incorporation**	**Class of shares**	**Equity holding**	
			2014	2013
			%	%
UEIP Pty Ltd	Australia	Ordinary	100	100
United Energy Finance Pty Ltd	Australia	Ordinary	100	100
Utilities Consulting Services Pty Ltd	Australia	Ordinary	100	100
United Energy Finance Trust	Australia	Units	100	100

28 Reconciliation of profit after income tax to net cash inflow from operating activities

	Consolidated entity Year ended	
	31 December 2014	31 December 2013
	$'000	$'000
Profit for the period	**904**	23,374
Depreciation and amortisation	**134,650**	138,259
Net (gain) loss on sale of non-current assets	**2,146**	4,520
Customer contribution in kind	**(7,503)**	(5,403)
Discount on loan	**152**	-
Change in operating assets and liabilities:		
(Increase) in trade debtors and bills of exchange	**(19,826)**	3,437
(Increase) in inventories	**(2,599)**	1,721
(Increase) decrease in deferred tax assets	**4,618**	21,897
(Increase) decrease in other operating assets	**265**	(1,698)
(Decrease) increase in trade creditors	**(3,731)**	(12,856)
(Decrease) increase in deferred tax liabilities	**27,871**	(6,227)
(Decrease) increase in other provisions	**1,346**	(5,993)
(Decrease) increase in derivative financial instruments	**7,692**	(23,047)

28 Reconciliation of profit after income tax to net cash inflow from operating activities (continued)

	Consolidated entity Year ended	
	31 December 2014 $'000	31 December 2013 $'000
Net cash inflow (outflow) from operating activities	**145,985**	137,984

In the directors' opinion:

(a) the financial statements and notes set out on pages 5 to 38 are in accordance with the *Corporations Act 2001*, including:
   (i) complying with Accounting Standards, the *Corporations Regulations 2001* and other mandatory professional reporting requirements, and
   (ii) giving a true and fair view of the consolidated entity's financial position as at 31 December 2014 and of its performance for the year ended on that date, and

(b) there are reasonable grounds to believe that the company will be able to pay its debts as and when they become due and payable.

Note 1(b) confirms that the financial statements also comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

This declaration is made in accordance with a resolution of directors.

Mr Peter Lowe
Director
Melbourne

Independent auditor's report to the members to the members of

United Energy Distribution Pty Ltd

{The Auditor's report will be provided by your Auditor.}

Appendix E: Reconciliation of Annual RIN to Statutory Accounts

This appendix addresses Section 1c of the Annual RIN.

Revenue

	Statutory Accounts	Regulatory Accounts	Difference
TOTAL	624,232	613,857	-10,375

Explanation of difference

Details	Amount
AMI Accrual	13,474
Mornington Claim	241
Interest income	-3,201
Customer Contributions	-20,951
Unrealised foreign exchange losses	62
TOTAL	**-10,375**

Operating expenditure

	Statutory Accounts	Regulatory Accounts	Difference
Operating Fee	65,412	55,028	-10,384
Operating Costs	91,674	78,862	-12,812
AMI		23,437	23,437
TOTAL	**157,086**	**157,327**	**241**

Explanation of difference

Details	Amount
Mornington claim	241

Capital expenditure

No difference between statutory and regulatory accounts.

Appendix F: Accounting policies and principles

UNITED ENERGY

1. Overview

UE is the licensed entity charged with carrying out the role of electricity distribution in accordance with all legal and regulatory requirements. The AER has made three final decisions that are relevant for the purposes of the Annual Financial RIN. These being:

- 2011 to 2015 Distribution determination
- 2011 to 2015 Public lighting determination
- 2012 to 2015 AMI Final Decision

These decisions provide the benchmarks against which actual expenditure is measured against, opening regulatory asset bases and depreciation allowances for the 2014 calendar year.

The information contained in the documents submitted to the AER was prepared is in line with United Energy's approved Cost Allocation Methodology.

The financial information has been reconciled with the relevant regulatory accounting statements and statutory accounts, and the principles underpinning the calculation of figures are in line with statutory accounting policies.

The remaining sections of this appendix provide details of United Energy's approach as follows:

- Section 2 – Cost allocation approach
- Section 3 – Cost Allocation Methodology
- Section 4 – Capitalisation Policy

UNITED ENERGY

2. Cost allocation approach

The following table provides details of United Energy's cost allocation. All costs have been directly allocated.

Table 1: Operating expenditure – Allocation approach

	Direct Allocation							Indirect Allocation							Overall opex TOTAL
	SCS	AMI	ACS	Public Lighting	Negotiated Services	Non-Regulated	TOTAL	SCS	AMI	ACS	Public Lighting	Negotiated Services	Non-Regulated	TOTAL	
Network Operating Costs	19,614	0	0	0	74	0	**19,688**	0	0	0	0	0	0	0	**19,688**
GSL payments	1,124	0	0	0	0	0	**1,124**	0	0	0	0	0	0	0	**1,124**
AMI	-5	22,947	0	0	0	495	**23,437**	0	0	0	0	0	0	0	**23,437**
Customer Service	8,453	299	3,539	0	50	253	**12,593**	0	0	0	0	0	0	0	**12,593**
Business Services	1,490	0	0	0	0	0	**1,490**	0	0	0	0	0	0	0	**1,490**
CEO	1,163	0	0	0	0	0	**1,163**	0	0	0	0	0	0	0	**1,163**
Commercial	5,125	0	0	0	0	0	**5,125**	0	0	0	0	0	0	0	**5,125**
Corporate Affairs	1,149	0	0	0	0	0	**1,149**	0	0	0	0	0	0	0	**1,149**
Facilities	3,254	0	0	0	0	0	**3,254**	0	0	0	0	0	0	0	**3,254**
Finance	10,928	127	200	0	77	115	**11,448**	0	0	0	0	0	0	0	**11,448**
HR	159	0	0	0	0	0	**159**	0	0	0	0	0	0	0	**159**
Internal Audit	937	0	0	0	0	0	**937**	0	0	0	0	0	0	0	**937**
Project 7-11	-673	0	0	0	0	0	**-673**	0	0	0	0	0	0	0	**-673**

Appendix F: Accounting policies and principles

	Direct Allocation							Indirect Allocation							Overall opex TOTAL
	SCS	AMI	ACS	Public Lighting	Negotiated Services	Non-Regulated	TOTAL	SCS	AMI	ACS	Public Lighting	Negotiated Services	Non-Regulated	TOTAL	
Regulatory	3,146	100	0	0	0	0	**3,246**	0	0	0	0	0	0	0	**3,246**
Customer Innovation	1,184	0	0	0	0	0	**1,184**	0	0	0	0	0	0	0	**1,184**
IT	16,973	0	0	0	0	0	**16,973**	0	0	0	0	0	0	0	**16,973**
TOTAL	**74,022**	**227**	**200**	**0**	**77**	**115**	**102,298**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**102,298**

3. Cost Allocation Methodology

See attached document.

4. Capitalisation Policy

See attached document.

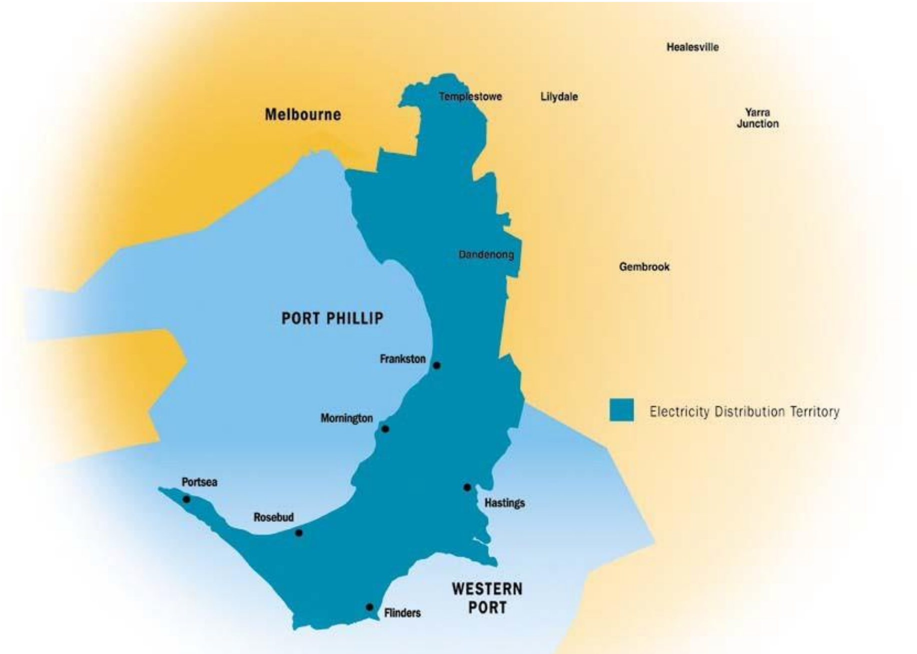
Cost Allocation Method

1 January 2016

Table of Contents

1 Introduction

United Energy Distribution (UE) is one of five electricity distribution network service providers operating under licence within the State of Victoria, with assets totaling approximately $3.0 billion. UE's network provides services to some 660,000 end-use customers in Melbourne's southern and eastern suburbs, with its area of operation confined to geographically defined boundaries set out in the Distribution Licence. A map is provided below:



UE is ultimately owned 66 per cent by Diversified Utility and Energy Trust (DUET) and 34 per cent by SGSP (Australia) Assets Pty Ltd (SGSPAA). Refer to section 5 for more details.

2 Version history and date of issue

Under clause 11.17.5 of the National Electricity Rules (Rules), UE submitted to the Australian Energy Regulator (AER) for approval a Cost Allocation Method (CAM) as part of its regulatory proposal for the 2011 to 2015 regulatory control period. That CAM (version 1.0) was approved by the AER on 18 June 2010 and commenced with effect from 1 January 2011.

Clause 6.15.4 (f) of the Rules permits UE with the AER's approval, to amend its CAM from time to time.

UE has chosen to submit an amended CAM to the AER for approval prior to its submission of its regulatory proposal for the 2016 to 2020 regulatory control period. The CAM has been amended principally to reflect changes to UE's distribution services classification for the 2016 to 2020 regulatory control period.

This CAM is version 2.0.

The date of issue is the date of approval.

The date of commencement is 1 January 2016.

On approval, UE will post this CAM on UE's website

(www.unitedenergy.com.au)[1].

[1] See clause 6.15.4(h) of the Rules

3 Nature, scope and purpose of the document

This document sets out the CAM to be adopted by UE for the purposes of allocating costs to distribution services in accordance with the requirements of the Rules, and for reporting historic and forecast cost information to the AER, for periods beginning on or after 1 January 2016[2].

Compliance with the conditions for approval of an amended CAM

This CAM meets the conditions for approval by the AER of an amended CAM, of clause 4.2(c) of the Cost Allocation Guidelines for Victorian electricity distribution network service providers dated June 2008 (CAG).

The descriptions provided later in this Section 3 demonstrate that the content and structure of UE's CAM together have an overriding objective of effectively promoting the Cost Allocation Principles set out in clause 6.15.2 of the Rules.

Clause 2.2.2 of the CAG requires the CAM to attribute and allocate costs based on the substance of underlying transactions and events. Sections 6 and 8 of this document set out a number of anticipated changes to the distribution service and accounting classifications on which the current CAM (v1.0) is based. Accordingly, a revision to the CAM is necessary to ensure that the forms of both UE's cost allocations and the CAM, properly reflect the changed substance of certain underlying transactions in order to not present a risk of material misstatement of costs directly attributed or allocated to UE's distribution services.

The differences between this CAM v2.0 and its predecessor CAM v1.0, reflect changes in classifications that are anticipated to come into effect on or after 1 January 2016. Table 3-1 below and Sections 6, 7 and 8 transparently detail the impact of the amendments. The allocators of shared cost are unchanged in the amended CAM. Because the changed transactions and events and their corresponding influences on allocated cost are not applicable to earlier periods, the amended CAM does not jeopardise the comparability of resultant financial information with earlier information provided by UE to the AER. Also because the changes are principally ones of presentation and categorisation not quantification, the amendments to the CAM are not quantifiable.

Consistency with Cost Allocation Principles

As required by clause 6.15.4(b) of the Rules and clause 3.1(b) of the CAG, this CAM gives effect to and is consistent with the CAG.

This CAM meets the requirements for UE's cost allocation principles and polices, set out in chapter 2 of the CAG, as follows:

- Clause 2.2.1(a) – Section 7 of the CAM contains detailed principles and policies to attribute costs directly to, or allocate costs between, different categories of distribution services to enable the AER to replicate reported outcomes and for the DNSP to demonstrate it is meeting the requirements of the CAG;
- Clause 2.2.1(b)(1) – Section 8 of the CAM contains two tables, titled Capital Activities and Maintenance Activities, that describe the nature and characteristics of each directly attributed cost item and the distribution service to which they are attributed;
- Clause 2.2.1(b)(2) – Section 8 of the CAM also lists shared costs and details how they are allocated to distribution services. The nature of the allocator and the reasons for its selection is described, as are the bases of and sources of information for the

[2] See clauses 1.4(b) and 5.1(b) of the CAG

calculation of the percentage allocators that is expected to change during the regulatory control period;

- Clauses 2.2.1(b)(1)(2) - Section 10 of the CAM describes how and where UE maintains records to enable the bases of attribution to be independently audited or otherwise verified;
- Clause 2.2.2 – Sections 7 and 8 of the CAM describe how costs are attributed or allocated based on the substance of the underlying transaction or event;
- Clause 2.2.3 – Sections 7 and 8 of the CAM also describe how attributions and allocations are determined by reference to distribution services;
- Clause 2.2.4 - Sections 7 and 8 of the CAM describe how the allocators meet the CAG's criteria for non-causal allocators;
- Clause 2.2.5 – Section 7 and the tables in Section 8 of the CAM describe how all cost categories are *either* directly attributed *or* allocated;
- Clause 2.2.6 – the CAM is consistent with the objectives of Rule 6.17 and distribution ring fencing objectives including *Electricity Industry Guideline No. 17: Electricity Ring-fencing Issue 1*, developed by the Essential Services Commission;
- Clause 2.2.7 – costs will not be re-allocated during the course of a regulatory control period;
- Clause 2.2.8 – the CAM has regard to previous cost allocations in accordance with the ESC distribution pricing determination and allows effective comparison of historical and forecast cost allocation between the period to which the ESC distribution pricing determination is applied and later regulatory control periods. This CAM applies historically consistent principles and polices to evolving market and regulatory circumstances.

Consistency with Cost Allocation Principles

Having met the requirements of the CAG, it follows that the CAM is consistent with the Cost Allocation Principles required by clause 6.15.2 of the Rules. For completeness, however, UE describes how the CAM meets those principles as follows:

- Clause 6.15.2 (1) – this CAM contains sufficient detailed principles and policies to allocate costs between different categories of distribution services to enable the AER to replicate reported outcomes;
- Clause 6.15.2 (2) – costs have been allocated according to the substance of a transaction or event rather than its legal form;
- Clause 6.15.2 (3) – costs have either been directly attributed to the services or costs have been allocated using an appropriate allocator;
- Clause 6.15.2 (4) – cost allocations are clearly described in the CAM including reasons for using specific allocators;
- Clause 6.15.2 (5) – costs are not allocated more than once;
- Clause 6.15.2 (6) – the principles, policies and approach used to allocate costs are consistent with the Distribution Ring-Fencing Guidelines; and
- Clause 6.15.2 (7) – costs allocated to a particular service will not be re- allocated to another service during the course of a regulatory control period.

Table 3-1: Comparison of historic cost allocation methods in CAM v1.0 and this CAM v2.0

Distribution service	CAM v1.0 method	This CAM v2.0 method
Standard Control	Costs are directly allocated in accordance with the description provided in CAM v1.0. Shared costs are allocated based on weighted average revenue.	Costs are directly allocated in accordance with the description provided in this CAM. Shared costs are allocated based on weighted average revenue.
Alternative Control	Costs are directly allocated in accordance with the description provided in CAM v1.0. Shared costs are allocated based on weighted average revenue.	Costs are directly allocated in accordance with the description provided in this CAM. Shared costs are allocated based on weighted average revenue.
Negotiated	Costs are directly allocated in accordance with the description provided in CAM v1.0. Shared costs are allocated based on weighted average revenue.	Costs are directly allocated in accordance with the description provided in this CAM. Shared costs are allocated based on weighted average revenue.
AMI Order In Council	Costs are directly allocated in accordance with the description provided in CAM v1.0 and the Cost Recovery Order In Council (CROIC). All costs charged to the CROIC are directly attributed.	Not applicable. The recovery of the costs of Advanced Metering Infrastructure services under the CROIC will cease on 31 December 2015, when the CROIC expires.
Non regulated	Not applicable	Costs are directly allocated in accordance with the description provided in this CAM. Shared costs are allocated based on weighted average revenue.

Note: This CAM provides sufficient disclosure of the bases of allocation to allow the AER or an independent party, to make an effective comparison of historical and forecast cost allocations under CAM v1 approved by the AER and the later regulatory control periods subject to this CAM.

4 Accountabilities for the CAM

UE is committed to implementing this CAM.

UE's Board of Directors (Board) is responsible for ensuring the overall performance and governance of UE and its subsidiaries.

In order to assist the Board in effectively discharging its powers and duties, it has delegated responsibility for the day-to-day operation and management of UE to the Chief Executive Officer (CEO), and the senior management team. The Board retains the ultimate legal responsibility for the exercise of powers delegated to senior management. The CEO and senior management are required to report to the Board on the exercise of these powers on an ongoing basis.

Specific responsibilities delegated to the CEO, Chief Financial Officer (CFO), General Manager Commercial and Company Secretary, General Manager Electricity Network, General Manager Regulation, General Manager Service Delivery, General Manager Asset Management, General Manager Customer & Technology and other senior management, are summarised in Section 5 of this CAM.

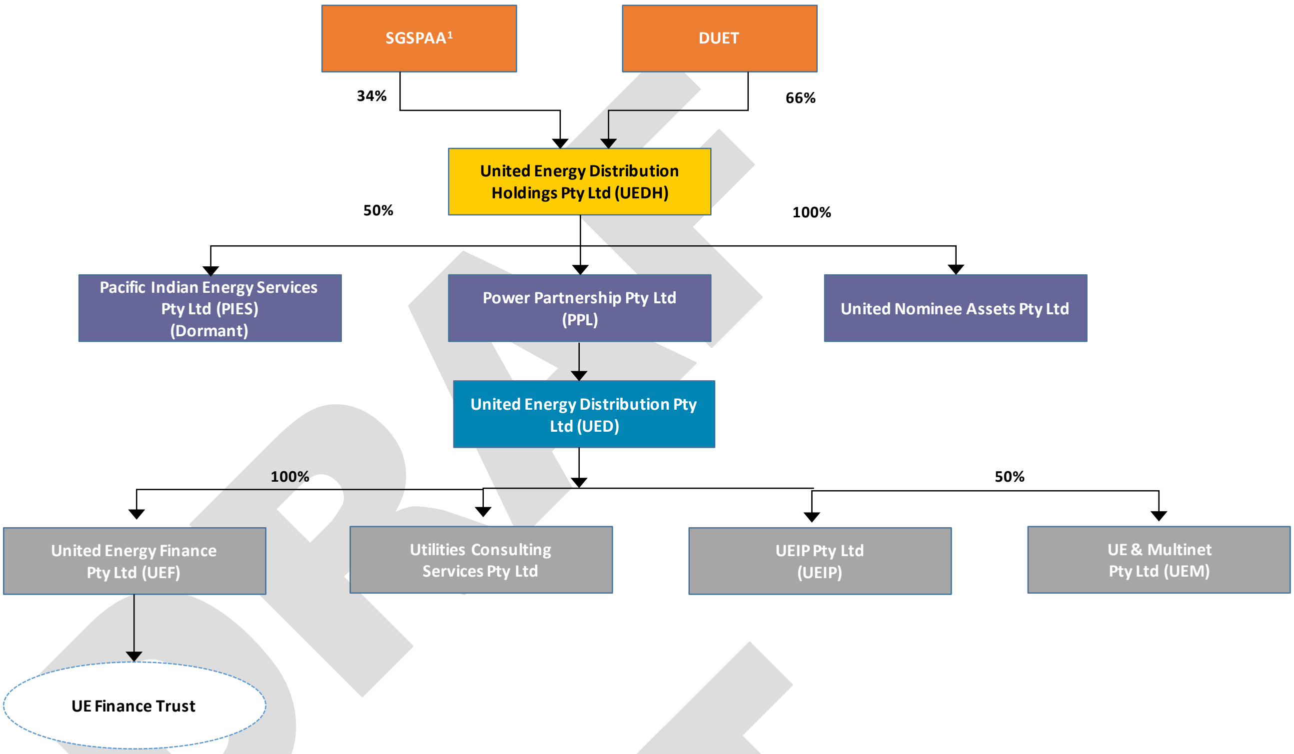
Responsibility for updating, maintaining and applying this CAM is with the CFO. The CFO is also responsible for internally monitoring and reporting on the application of this CAM.

In meeting these responsibilities, the CFO is accountable to the Board, as outlined above.

5 Description of UE's corporate and operational structures

Corporate structure

United Energy Distribution Holdings Pty Limited (UEDH) is 66 per cent owned by the DUET Group (DUET), with the remaining 34 per cent owned by SGSP (Australia) Assets Pty Ltd (SGSPAA).



1 SPIAA changed its name to SGSP (Australia) Assets Pty Limited (SGSPAA) on 3 January 2014

The UE Group has a strong shareholder base. DUET is a large Australian infrastructure specialist fund and SGSPAA is a joint venture between the Singapore-based Singapore Power Limited (SP) and the Chinese-backed State Grid Corporation of China (SG). Over the years, the shareholders have provided resourcing, technical and financial support to the business, as has been required.

DUET is listed on the Australian Securities Exchange (ASX) under the ticker code (DUE.ASX) with a market capitalisation of approximately $3.2billion as at 30 June 2014. DUET was listed on the ASX on 13 August 2004.

SGSPAA is 60 per cent owned by State Grid International Development Australia Investment Company Limited, a wholly owned subsidiary of State Grid Corporation of China (rated Aa3 (stable) by Moody's) via State Grid International Development Limited. The remaining 40 per cent is owned by Singapore Power International Pty Ltd, a wholly owned subsidiary of Singapore Power Limited (rated AA (stable) by Standard & Poors.

Organisational and operational structure

UE is a stand-alone distributor and does not retail electricity, nor provide construction or maintenance services to any other business.

UE is governed by a Chairman and a Board of Directors drawn from its major shareholders.

The roles and responsibilities of each member of UE's senior management team are described below:

- CEO – Company management, strategic planning, business structure, stakeholder relations, board management
- CFO – Statutory and management reporting, financial planning, annual budgets, taxation, treasury, accounts payable, accounts receivable, payroll, regulatory accounting, accounting policies
- General Manager Customer & Technology – Strategic IT management and planning, IT contractor management, desktop management, help desk, customer & market services
- General Manager Commercial (Company Secretary and Legal Counsel) – Company secretarial services, legal services, easements, contract management
- General Manager Electricity Network and General Manager Service Delivery - Distribution asset planning, control room operations, asset management, maintenance planning, engineering, capital construction, field maintenance activities, contractor management
- General Manager Regulation - Regulatory compliance, pricing submissions, regulatory policy, performance reporting

UE has service agreements with the following third parties -

- ZNX/Tenix - Operating and maintenance service agreements (OMSAs) for the construction, maintenance and operation of its distribution network. ZNX is fully owned by SPIAA.
- Skilltech – Manual scheduled meter reading, special meter reads, on-site de-energisation and re-energisations
- Aegis – Customer and market services
- Accenture – Major IT system applications support e.g. SAP
- CGI – IT infrastructure and Service Desk Support

UE also receives management services from DUET, a shareholder.

Related party transactions are disclosed in UE's audited statutory and regulatory financial statements in accordance with statutory and regulatory accounting disclosure requirements.

6 Categories of distribution services

Distribution services provided by UE are classified as either:

- a direct control service;
- a negotiated distribution service;
- an advanced metering infrastructure (AMI) service recoverable under Victoria's Cost Recovery Order in Council (CROIC); or
- a non-regulated service.

Direct control services are further divided into:

- standard control services; and
- alternative control services.

These categories of service are explained further below.

1. Direct control services - Standard control services

Services provided as standard control services are recovered via Distribution Use of System tariffs and make up the bulk of services provided by UE. These services are ultimately provided to all end-use customers connected to UE's electricity distribution network. Services include the maintenance and operation of UE's distribution system including vegetation management, fault restoration, asset inspection, planned maintenance, reactive maintenance, emergency management, and the 24 hour control room. Capital expenditure is incurred to provide standard control services including ensuring capacity requirements are met, replacement capital, asset refurbishment, new connections services and network growth.

UE proposes to classify elective under-grounding and rearrangement of network assets at a customer's request as standard control services, with effect from 1 January 2016. These services have been classified as alternative control services in the regulatory control period ending 31 December 2015.

2. Direct control services - Alternative control services

Alternative control services are recovered via specific prices to those customers that have requested the service. Alternative control services are not recovered via Distribution Use of System tariffs. These services include: the energisation and de-energisation of existing connections, temporary supplies, service truck visits routine connections, elective undergrounding (proposed to be treated as standard services from 1 January 2016 as per above paragraph) and low voltage covers.

Type 5 and type 6 metering services are excluded from the service classification framework of the National Electricity Rules until 31 December 2016 when the Victorian derogation from the Rules expires (or earlier if national arrangements for metering competition for small customers are developed and adopted in Victoria before that time).

UE proposes that all metering services that it provides in its capacity as the "default Metering Coordinator" for new customers in its distribution area who cannot obtain a competitive market offer, will be provided as alternative control services.

For the period 1 January to 2016 to the end of the Victorian derogation, and in accordance with the AER's preliminary positions on a replacement Framework and Approach for Victoria's distribution businesses for the regulatory control period commencing 1 January 2016 ("the AER's preliminary view"), UE proposes to classify type 5 and type 6 metering installation services as alternative control services. These services will be open to competition after the end of the derogation.

3. Negotiated services

Services provided as negotiated services are recovered via specific prices to those customers that have requested the service. Negotiated services are not recovered via Distribution Use of System tariffs. Negotiated services include relocation and alteration of public lighting assets and new public lighting. In response to the AER's preliminary view, UE proposes with effect from 1 January 2016, to reclassify the operation, maintenance and replacement of its existing public lighting assets as two separate negotiated services, namely:

- Operation, maintenance and repair; and
- the replacement of existing public lighting assets.

These services have been classified as alternative control services in the regulatory control period ending 31 December 2015.

4. AMI services – Cost Recovery Order in Council (CROIC)

Advanced Metering Infrastructure (type 5 and type 6 metering) services are recovered under a specific Victorian Order in Council (AMI CROIC). The activities for which costs are recovered pursuant to the AMI CROIC are set out in schedule 2 section 2.1 of that document. This arrangement expires on 31 December 2015.

5. Non regulated services - AMI services

With effect from the end of the Victorian derogation, the provision of type 5 and type 6 meters in UE's distribution area will be open to competition. UE proposes that the provision of these services for new sites will be unregulated.

UE currently does not anticipate providing any other non-regulated distribution services.

The AER's final classification of services

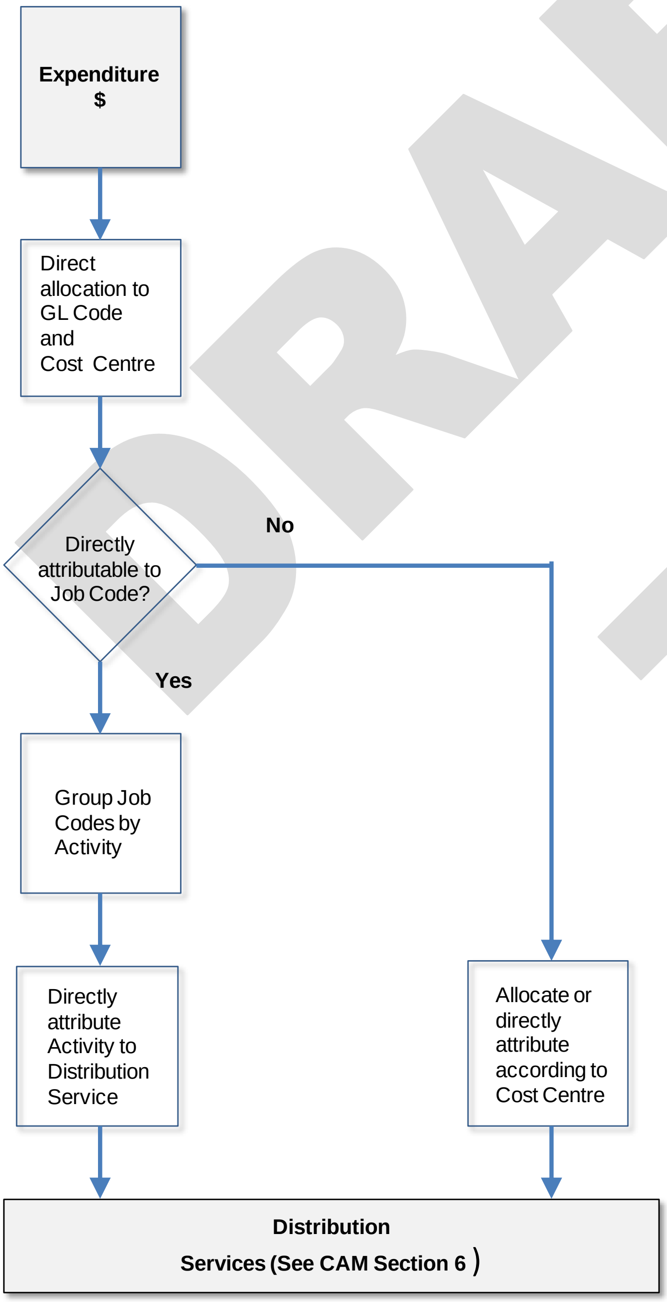
The changes in service classification described above are consistent with UE's response to the AER's preliminary views. UE will amend this section of the CAM in accordance with clause 4.2(a) of the CAG in order to apply the AER's final classification of services.

7 Detailed principles and policies for cost attribution

Overview

UE utilises SAP as its financial management and works management system. UE's SAP system is structured to comply with statutory reporting requirements and with this CAM. It is also able to provide a database of information for management reporting purposes.

The cost attribution process is summarised in the following diagram. This process is the same as that described in the AER approved CAM v1.0. The following explanations also refer to Section 8 which provides more detail of cost codes and bases of allocation



In summary:

- each cost incurred (capital and non-capital) is coded and directly attributed to both a general ledger account cost code that describes the nature of the cost input, and a cost centre code to allow management responsibility to be assigned to each cost;
- typically, a cost centre reflects a line of internal service or management responsibility such as finance, network management, control room or regulatory costs;
- some costs are also directly attributed to a job ledger code that allows the purpose of those costs to be identified for more detailed reporting of the costs of capital and operating and maintenance activities;
- job ledger codes are normally used to collect directly attributable costs. Therefore these costs are not normally relevant to shared costs. Typically, shared costs that are not assigned to a job code are for corporate services, or are in the nature of overheads. Those cost centre costs which are not attributed to job codes are attributed to distribution services based on the allocation rules provided in Section 8 under the heading “Allocations of shared costs”;
- each job ledger code is assigned (directly attributed) to an activity code. Activity codes summarise multiple job ledger codes. This allows UE to group the costs of individual jobs by like activities; and
- activity costs are either directly attributed or allocated to distribution services according to the rules in Table 8-1 and Table 8-2 in Section 8, titled “Capital activities” and “Maintenance activities.”

Consistent with clause 3.2.(a)(6) of the CAG, the process described above and the further information set out at Section 8, apply to all expenditure regardless of the party with whom the expenditure is incurred and therefore includes related party expenditure.

General ledger account codes

The broad grouping of general ledger account codes is as follows:

- Labour;
- Materials;
- External services;
- Contracts;
- Direct overheads;
- Transport & logistics; and
- Miscellaneous.

Attribution of Service Providers Costs

OMSA Service Providers (ZNX/Tenix)

OMSA labour

The OMSA labour cost, comprise actual costs of Service Providers (SPs) direct employees, at the actual employee’s on-costed labour hourly rate by the actual hours worked on UE jobs as per their completed timesheets. All OMSA labour is costed to individual UE job codes.

OMSA materials & Inventory Carrying Cost

Materials comprise strategic spares and materials supplied for capital construction and maintenance activities.

Materials supplied for capital construction and maintenance activities are directly attributed to job codes at cost plus a surcharge to recover the cost of managing the logistics function. This includes the costs of:

- purchasing;
- warehousing;
- premises; and
- delivery

OMSA Sub-contractors

Subcontractor costs are incurred at agreed on-costed hourly rates by actual hours worked on UE jobs, passed through to UE at the invoiced amount and costed to individual job codes.

OMSA other services

The costs of other services provided under the OMSAs are directly attributed to a job code.

Other Main Operational Service Providers

Skilltech

Skilltech services encompass manual scheduled meter reading, special meter reads, on-site de-energisation and re-energisation. Skilltech charges are based on agreed service rates by quantity delivered, which are directly costed to CROIC and ACS respective cost centres based on actual services.

Aegis

Aegis provides customer management services including call centre, faults management, billing, service desk, connections, meter data management, route management etc.

Aegis charges are based on contracted employee rates by number of units (hours) delivered, which are directly costed to SCS, CROIC, ACS respective cost centres based on percentage allocations based on volumes profile of services provided.

Other Third Party Costs

The costs of goods and services provided by other parties (such as audit, professional services, IT service providers) are directly attributed to a cost centre and if relevant, attributed to a job code based on the causal basis.

Principles additional to Cost Allocation Principles and the CAG

Consistent with the AER approved CAM v1.0 UE applies the following additional principles:

- an item is material if its omission, misstatement or non-disclosure has the potential to prejudice the understanding of the financial position of UE's distribution services, gained by an assessment of financial information relating to UE; and
- UE applies a fully distributed approach to cost allocation, that allocates or directly costs the total costs to distribution services, which reconcile to UE's total input costs. UE does not apply an avoided cost allocation methodology.

8 Directly attributed and allocated costs

The table below explains which distribution services the activity codes will be directly attributed to.

Each activity in Table 8-1 and Table 8-2 is wholly and exclusively associated with a single distribution service in any single period. Where AMI activities in Table 8-1 and Table 8-2 refer to more than one service, this is because the regulatory service classification is expected to change on 1 January 2017, as explained in Section 6.

Table 8-1: Directly Attributed Capital Activities

Activity	Service
Reinforcement	Standard control
New customer connection	Standard control
Reliability & quality maintained	Standard control
Environmental, safety & legal	Standard control
SCADA /Network control	Standard control
Non network general - IT	Standard control
Non network general - other	Standard control
Accumulation Meters (AMI)	Alternative control
Manually read interval meters	Alternative control or Non-regulated for non default Metering Coordinator activities (See Section 6)
Remotely read interval meters & transformers	Alternative control or Non-regulated for non default Metering Coordinator activities (See Section 6)
AMI communication	Alternative control or Non-regulated for non default Metering Coordinator activities (See Section 6)
Metering data services (IT)	Alternative control or

Activity	Service
	Non-regulated for non default Metering Coordinator activities (See Section 6)
Metering data services (other)	Alternative control or Non-regulated for non default Metering Coordinator activities (See Section 6)
Public lighting - energy efficient	Negotiated
Public lighting - non energy efficient	Negotiated
Other - fee based services	Alternative control
Other - quoted services	Alternative control
Elective undergrounding and rearrangement of network assets at customers' requests	Standard control

Table 8-2: Maintenance Activities

Activity	Service
Routine	Standard control
Condition based – Standard Control Services	Standard control
Condition based – Alternative Control Services	Alternative control
Emergency	Standard control
SCADA/Network Control	Standard control
Other – Standard Control Services	Standard control
AMI	Alternative control or Non-regulated for non default Metering Coordinator activities (See Section 6)
Public Lighting	Negotiated

Activity	Service
Alternative control – other	Alternative control
Negotiated Services	Negotiated

Allocations of shared costs

Certain cost centres record shared costs that are not job-costed. These cost centres which generally relate to corporate or support activities, are listed below.

- Regulation
- Legal
- Finance
- IT
- CEO
- Customer & Market Services
- Internal Audit
- Corporate Affairs
- HR
- Administration

These cost centre costs are allocated to individual services based on the weighted average service revenue.

It should be noted that to the extent that costs are directly allocated to distribution services, these costs are excluded from the above allocations. For example, expenditure for the delivery of AMI services – Cost Recovery Order in Council (CROIC) is accounted for by specific invoices and by directly attributed employees and the use of time allocations. This allows expenditure on these services to be directly attributed and hence is excluded from the above allocations.

This method of allocation:

- is consistent with that used in UE's CAM v1.0 that has been approved by the AER;
- is based on a basis of allocation which is well accepted and provides a strong correlation with the levels of resources and services that the shared costs represent and the likely relative utilisation of those resources and services by the different distribution services to which costs are allocated;
- applies to costs for which causal allocators cannot be established with undue cost and effort. This is because these costs are predominantly "fixed" costs for corporate services which are necessarily incurred to enable the delivery of services as a whole and are not caused by variations in levels of specific services;
- applies to costs which in total amounted to less than 14% of total operating and capital expenditure (excluding finance charges, depreciation and amortisation) in calendar year 2013; and
- resulted in the following percentage allocations of operating cost in the calendar year 2013.

Table 8-3: Calendar year 2013 shared cost allocations

Standard Control Services	Alternative Control Services	Negotiated Services	Non -Regulated Services	Total
96%	4%	0%	0%	100%

The numeric quantity or percentage of each allocator will change from time to time throughout the regulatory control period, because the quanta of the cost drivers on which the allocators are based, are expected to change in the normal course of events.

The information from which the percentage of each allocator will be calculated, will be sourced from UE’s accounting records (see Section 10).

9 Compliance monitoring

The Chief Financial Officer is responsible for monitoring UE's compliance with the CAM and the CAG. UE has an Audit and Risk Committee that monitors compliance, including compliance with the CAM.

The Chief Finance Officer's accountabilities for these responsibilities are described in Section 5.

Independent auditors will provide the assurance that the AER may require in connection with this CAM in relation to its application to Regulatory Information Notices, regulatory financial statements and any Regulatory Proposal, for example.

The cost allocation methodologies described in this CAM will be provided to all related parties – specifically DUET, UEDH and ZNX. Major contractors will also be provided a copy of the approved CAM, noting that the prices paid by UE for individual services will be based on the contractor cost structures and allocations. Contractors and related parties will be required to comply with this CAM to the extent that the law requires them to comply.

Contractors and related parties will provide sufficient detail to enable UE to cost services directly to specific job ledgers in accordance with this CAM.

This CAM complies with the existing ESCV ring fencing guidelines. This CAM will be amended (if required) when the AER replaces the existing ring-fencing guidelines.

All queries regarding this CAM can be directed to:

Andrew Schille

General Manager Regulation – United Energy aschille@ue.com.au

(03) 8846 9860

10 Records Maintenance

In order to:

- demonstrate the attribution of costs to, or allocation of costs between, different categories of distribution services in accordance with this CAM to the AER under clause 5.2 of the CAG; and
- allow attributions or allocation to be audited or otherwise verified by a third party, including the AER, as required

UE will maintain records of attributions and allocations as follows:

- all financial records will be kept in UE's financial systems (SAP);
- UE's statutory financial statements and associated accounting records will form the basis of all reporting requirements;
- all records will be kept for at least seven years; and
- all records will be available to independent auditors and the AER.

Also, any changes to this CAM will be:

- supported by documentation and signed off by UE management prior to being submitted for AER approval; and
- subject to prior approval by the AER.

11 Date of effect

The date of effect for this CAM is 1 January 2016.

Fixed Asset Policy

UNITED ENERGY

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Environment

United Energy asks that you consider the environment before printing this document.

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This document is controlled within the United Energy Policies and Procedures System.

	Proposed By:	Approved By:
Name:	S. Edwards	D. Strang
Title:	Fixed Asset Accountant	Chief Financial Officer
Signature:	SEdwards	
Date:	30 April 2014	5/5/2014
Document Number:	FAM-022-POL	
Policy effective date:	30 April 2014	
Next review date:	30 April 2017	

Contents

1 Purpose

The purpose of the Fixed Asset Policy paper is to establish principles by which United Energy accounts for items of Property, Plant & Equipment and selected Intangible assets in its General Ledger to ensure fixed asset information is accurately reflected in generating financial and management reports.

2 Executive Summary

This policy provides an overview of the capitalisation principles for United Energy. This policy has considered accounting, tax, regulatory and business considerations in assessing whether an asset should be capitalised.

This policy sets out high level procedures which will enable the fixed asset registers to accurately record, update, extract and report on fixed asset information in the general ledger for financial and management reporting, tax, legal and regulatory.

3 Definitions

For purposes of this policy, unless otherwise stated, the following definitions shall apply:

AASB	Australian Accounting Standards Board
Accumulated Depreciation	The total depreciation taken for an asset since it was placed in service. Also known as life-to-date depreciation and depreciation reserve
Amortisation	Amortisation is the systematic allocation of the cost of an intangible asset over its useful life
AER	Australian Energy Regulator
Asset	A resource controlled by an entity as a result of past transactions and from which future economic benefits are expected to flow to the entity. The common understanding of an asset is that it is an item (tangible or intangible) that is considered to have an enduring value
Asset Type	Either tangible, intangible or in kind
Board	The Board of United Energy Distribution Holding Pty Ltd and all of its subsidiaries, known as UE Group (UE)
Books	Shows the financial information regarding the expenditure, depreciation and treatment of the asset within the Fixed Asset module.
Capex	Expenditure incurred on capitalised assets
Capitalised Assets	Assets recorded on a fixed asset register that depreciate or amortise where applicable and have a useful life of more than one year

Capital Project	A project to build or purchase one or more depreciable or amortisable fixed assets
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIRB	Capital Investment Review Board
Depreciate	To spread the cost of an asset over its useful life. Depreciation expense is charged for the asset each period. The total depreciation taken for an asset is stored in the accumulated depreciation account
Expenditure	This represents costs incurred by United Energy in the operation of the business
Expensed	Expenditure incurred is included as operational expenditure attributing to the statement of income position for the period (i.e. profit and loss). It is also referred to as 'opex' expenditure.
Fixed Asset	An asset owned by the business recorded on the SAP Fixed Asset Register
Future economic benefit	Is synonymous with the notion of service potential. The future economic benefit embodied in an asset is the potential to contribute, directly or indirectly for a period greater than one year, to the flow of cash and cash equivalents to United Energy
Intangible Asset	An intangible asset is an identifiable asset without physical substance
MG	Multinet Group Holding Pty Ltd and all its subsidiaries
Opex expenditure	Refer 'Expensed' definition
IS	Information Systems
IT	Information Technology
ITEF	Information Technology Executive Forum

OMSA	Operational and Management Service Agreement. An agreement between UE and their Service Providers covering multiple issues.
SAP	Software used by UE to record and manage it business processes including the general ledger
Period	The time period of 12 months
Procurement policy	This is the policy that provides guidelines and controls for purchasing in UE & MG
PP&E	Property, plant and equipment are tangible items that: (a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and (b) are expected to be used during more than one period
PM Module	Plant Maintenance Module of SAP. This module contains operational information on selected network assets.
Service potential	The total future service capacity of an asset. It is normally determined by reference to the operating capacity and economic life of an asset.
Tangible Asset	Tangible assets are items of PP&E that: (a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and (b) are expected to be used during more than one period
UE	United Energy Distribution Holdings Pty Ltd and all of its subsidiaries
Useful life	The period over which an asset is expected to be available for use by an entity
WBS	Work Breakdown Structure is a SAP term used to identify expenses and capital purchases
WIP	Work In Progress represents capitalised expenditure on assets that are either not completed, not installed, not available or not ready for use

4 Scope

The policy is intended to set out guiding principles United Energy should apply when evaluating whether expenditure should be capitalised or expensed. The policy identifies types of assets and covers high level classifications of assets and sets out the significant events that may occur in a fixed asset register during the life of an asset.

The policy does not represent a full set of instructions for capitalising an asset but rather a set of guidelines for assessment. Disclosures are not detailed in this policy document.

The policy does not cover intangible assets that are not recorded in the SAP Fixed Asset module such as goodwill, licences etc.

This policy does not address:

- Impairment as outlined in AASB136 *Impairment of Asset*. This is addressed in policy COR-057-POL
- The justification and approval of expenditure as this is covered in other policies, primarily the procurement policy, PRO-004-POL
- Insurance of assets as this is covered in insurance policy UE-MGH CI 001
- Leased Assets as outlined in AASB 117 *Leases*
- Customer Contributions
- Inventories as outlined in AASB 102 *Inventories*
- *Non Current Assets held for sale and Discontinued Operations AASB 5*

5 Policy

5.1 Types of Fixed Assets

An asset is a resource controlled by an entity as a result of past transactions and from which future economic benefits are expected to flow to the entity[1]. The common understanding of an asset is that it is an item (tangible or intangible) that is considered to have an enduring value. **To be recognised as an asset it has to have a useful life of more than one year and a measurable value.**

Fixed assets on the SAP fixed asset register are categorised as either tangible or intangible assets.

5.1.1 Tangible Fixed Assets:

Where a fixed asset is categorised as tangible, it is classified on the balance sheet as part of Property, Plant & Equipment and subject to the Australian Accounting Standards Board Standard 116 *Property, Plant and Equipment* (AASB 116) requirements.

Property, plant and equipment are tangible items that:

a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and
b) are expected to be used during more than one period.[2]

A tangible asset is a physical asset i.e. it can be physically seen and touched. Examples include land, buildings, network assets, plant, equipment, motor vehicles, office furniture etc.

5.1.2 Intangible Fixed Assets:

Where a fixed asset is categorised as intangible, it is classified on the balance sheet as part of Intangible Assets and subject to the Australian Accounting Standards Board Standard 138 *Intangible Assets* (AASB 138) requirements.

An intangible asset is an identifiable asset without physical substance.[3]

An example of an intangible asset on the fixed asset register is software. There can be other intangible assets such as goodwill and licences however these are outside the scope of this policy.

Refer to section 5.6 of this policy for more detail.

[1] AASB 138, paragraph 8

[2] AASB 116, paragraph 6

[3] Based on the definition in AASB 138, paragraph 8

5.1.3 In Kind Assets:

An in-kind asset is an asset or a portion of an asset that is gifted to UE by a customer. The asset arises where a customer elects to build an asset instead of UE building the asset. Ownership of the asset to UE is handed over on completion. The customer's contribution towards the asset is called an 'in-kind' contribution.

The value of United Energy's network assets is increased by the estimate of the value of the 'in-kind' portion of the asset and offset with the recognition of revenue for 'in-kind contributions'. This is similar to a donation with the distinguishing factor being the customer is required to gift the assets to the distribution company according to the current regulatory regime. An in-kind asset is also a type of tangible asset.

5.2 What's the difference between "expensed" and "capitalised"?

Expensed This means that the expenditure incurred is included as operational expenditure attributing to the statement of income position for the period (i.e. profit and loss). It is also referred to as 'opex' expenditure.

Capitalised This means that the expenditure is recognised as an asset in the balance sheet and is depreciated or amortised over the life of the asset which must be greater than one year. It is also referred to as 'capex' expenditure.

5.3 Identifying Expenditure to be Capitalised

United Energy has no dollar amount threshold for expenditure to be considered of a capex or opex nature. A common misconception is that the business has a capital threshold of $300, $500 or $1,000 below which all expenditure is considered to be opex in nature. This is incorrect. All expenditure must be considered against the statements contained in this policy for a decision on whether the expenditure is classified as capex or opex.

Decisions to either capitalise or expense expenditure incurred in relation to the acquisition or construction of assets is largely a matter of professional judgement. This view is reiterated in the accounting standards, which offer guidance to help professionals make these decisions but provide few examples of costs that must be treated as either capital or expense.

If after reading this policy, further guidance is required, contact the Fixed Asset Accountant.

<u>Recognition Criteria:</u>

There are different criteria for recognising tangible and intangible assets.

<u>Tangible:</u>
The cost of an item of property, plant and equipment shall be recognised as an asset if, and only if,
a) It is probable that the future economic benefits associated with the item will flow to the entity; and
b) The cost of the item can be measured reliably[4].

[4] AASB 116, paragraph 7

Intangible:

The recognition of an item as an intangible asset requires an entity to demonstrate that the item meets:

(a) The definition of an intangible asset
  - *i. Identifiable i.e. it is separable or arises from contractual or other legal rights*
  - *ii. The entity has control over the asset*
  - *iii. Future economic benefits must flow from the asset e.g. revenue from the sale of goods or services, cost savings or other benefits resulting from the use of the asset by the entity and*

(b) The cost of the item can be measured reliably[5].

For the elimination of doubt, probable future economic benefits means the asset is expected to be used during more than one period, i.e. greater than one year.

It is worth noting that expenditure is capitalised until an item of property, plant and equipment is in the location and condition necessary for it to be capable of operating in the manner intended by management.[6] This will need to be assessed on an asset by asset basis as management intentions may change on completion of an asset. Refer to section 5.6.2.1 for an example.

This means allowable expenditure can be accumulated as capital up to the time the asset is installed and ready for use, after which, certain expenditure must then be expensed.

Allowable Expenditure for Capitalisation under the Accounting Standards i.e. Capex:

AASB 116 para 11	Items of property and equipment may be acquired for safety and environment reasons. Such acquisitions although possibly not directly increasing the future economic benefits of any existing item of PP&E may be necessary for an entity to obtain a future economic benefit from its other assets. For instance, the expenditure of upgrading plant and equipment to meet more stringent environmental regulations could be capitalised on the basis that the business could not operate the assets and derive an income without first meeting the regulations and incurring the expenditure.
AASB 116 para 13	Partial replacement of an asset can be capitalised where this contributes to future economic benefits of the asset in that they either: • Extend the useful life of an asset • Improve its output • Reduce the operating cost of the asset. The carrying amount of the parts that are replaced needs to be identified and retired. Repairs and maintenance costs are excluded from being capitalised, refer to 'Disallowable Expenditure for Capitalisation under Accounting Standards' in this policy.
AASB 116 para 14	Costs incurred in performing regular major inspections for faults regardless of whether parts of the existing assets are replaced. Any remaining carrying amount of the cost of previous inspection must first be derecognised.
AASB 116 para 16 (a)	The purchase price of an item of PP&E, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.
AASB 116 para 16(b)	Any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

5 AASB 138, paragraph 11 to 24

6 AASB 116, paragraph 20

AASB 116 para 16(c)	The initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either: • when the item is acquired; or • as a consequence of having used the item during a particular period. Note: These costs may arise under a legal or constructive obligation per AASB 137 *Provisions, Contingent Liabilities and Contingent Assets*, paragraph 14 (a).
AASB 116 para 17(a)	Costs of employee benefits (as defined in AASB 119 *Employee Benefits*) arising directly from the construction or acquisition of the item of property, plant and equipment.
AASB 116 para 17(b)	Costs of site preparation.
AASB 116 para 17(c)	Initial delivery and handling costs.
AASB 116 para 17(d)	Installation and assembly costs.
AASB 116 para 17(e)	Cost of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment).
AASB 116 para 17 (f)	Professional fees. Note training is not included as part of professional fees.
AASB 116 para 49	Depreciation of pre-existing assets employed in the production of a new asset (i.e. depreciation expense directly attributable to equipment used in the construction of network asset).
AASB 116 para 22	The cost of a self-constructed asset is determined using the same principles as for an acquired asset. This means a self-constructed asset's cost includes direct material, direct labour, any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management and an appropriate proportion of any directly attributable production overheads.
AASB 123 (12)	Interest (or borrowing costs) associated with funds borrowed expressly for the purpose of obtaining a qualifying assets. A qualifying asset is defined in AASB 123 para 5 as 'An asset that necessarily takes a substantial period of time to get ready for its intended use or sale'.
UIG 1031 para 7	GST that is not recoverable from the tax authorities.

In addition to the above expenditure may be capitalised where it has been incurred to remove an asset and replace it with another asset and this expenditure is incidental, difficult to separate from the overall expenditure and also incurred to install the replacement asset, E.g. if a pole is being replaced, the labour cost incurred to remove the old pole before the replacement pole can be installed may be capitalised. If expenditure is incurred to remove an existing asset without installing a new asset then this expenditure must be expensed as it has no future economic benefit.

All expenditure to be capitalised is subject to the "*measurement at recognition*" criteria as per AASB 116 paragraph 15 & AASB 138 paragraphs 18 to 24 which requires all capitalised expenditure to be measured at its cost.

Disallowable Expenditure for Capitalisation under the Accounting Standards

AASB 116 para 12	The costs of day-to-day servicing of the asset. This may include labour and consumables and the cost of small parts. The purpose of these expenditures is often described as 'repairs and maintenance'. Expenditure that does not increase the level of economic benefits that flow from the use of an asset in future periods must be treated as expense when incurred.
AASB 116 para 19(a)	Costs of opening a new facility.
AASB 116 para 19(b)	Costs of introducing a new product or service (including costs of advertising and promotional activities).
AASB 116 para 19(c)	Costs of conducting business in a new location or with a new class of customer.

AASB 116 para 19(c), AASB 138 para 15 and AASB 138 para 67(c)	Costs of staff training. An entity may have a team of skilled staff and may be able to identify incremental staff skills leading to future economic benefits from training. The entity may also expect that the staff will continue to make their skills available to the entity. However, an entity usually has insufficient control over the expected future economic benefits arising from a team of skilled staff and from training for these items to meet the definition of an intangible asset.
AASB 116 para 19(d)	Administration and other general overhead costs.
AASB 116 para 20(c)	Costs of relocating or reorganising part or all of an entity's operations. This means the relocation costs of moving an existing physical asset from one location to another cannot be capitalised.
AASB 116 para 20	Costs are excluded from capital once the asset is in the location and condition necessary to be capable of operating in the manner intended by management.
AASB 116 para 21	Incidental income or expense generated by the asset prior to it being capable of being used for its intended purposes.
AASB 116 para 22	The cost of abnormal amounts of wasted material, labour or other resources included in self-constructing an asset.
UIG 1031 para 6	GST that is recoverable from the tax authorities.
AASB 116 para 48	Depreciation expense, unless it is included in the carrying amount of another asset as per AASB 116 para 49.
AASB 138 para 97	Amortisation of intangible assets unless AASB 138 or another accounting standard permits or requires it to be included in the carrying amount of an asset.

5.4 Capital Expenditure Financial and Procurement Controls

Capital expenditure has various types of categories as outlined in the sections above. This section outlines the framework of documents that establish the procurement and financial controls over the capital expenditure within the UE business for each category of capital.

Some non-network projects are also governed by individual steering committees.

5.4.1 Capital Expenditure Procurement Controls

There are a number of documents that create a procurement capital expenditure control framework. Each document contains specific controls within the capital expenditure process. The documents (other than this policy) include:

- Procurement Policy – Provides Guidelines and controls for all expenditure procurement
- Procurement Manual – Provides procedural approach for purchasing
- Delegation of Authority Policy – Establishes purchasing authority
- Accounts Payable Policy – Provides overview of controls over payments for all expenditure

5.4.2 Capital Expenditure Financial Controls

There are a number of documents that establish the financial controls for capital expenditure. Each document contains specific controls within the capital expenditure process. The documents (other than this policy) include:

- Investment Management Procedure – Controls capital allocation in SAP
- Annual Budgeting Policy – Controls the total allowed expenditure for the financial year
- Forecasting Policy – Provides controls over expected capital expenditure for the forecast period to compare against the approved budget
- CIRB Charter – Review of capital expenditure especially capital expenditure greater than $1m and any capital expenditure that may impact UE's risk profile (this is discussed further below)
- IT Project Financial Management Process

5.4.3 CIRB Sub Categories and OMSA Capital Expenditure Controls

There are additional controls within the CIRB charter which has a summary of the UE capital expenditure controls. This sets out the procedure for authorisation which is dependent on the category of capital expenditure. The categories of expenditure subject to the CIRB Charter are as follows:

Capex Category	Definition
Standing Capex	This relates to expenditure as detailed in the OMSA where there are prescribed rates with corresponding thresholds. This expenditure is incorporated into the annual capital expenditure budget. This is approved prior to the start of the financial year by the General Manager Electricity Networks and General Manager Service Delivery.
Individual Capex Projects	This relates to capital expenditure on individual projects and is governed via a tiered process: • Small - less than $20k • Medium - between $20k and $100k • Large - greater than $100k # Refer to the CIRB Charter for approvers of each tier.
Customer Initiated Capital (CIC)	This relates to capital expenditure initiated by customers and is governed by a tiered process: • Small - less than $20k • Medium - between $20k and $100k • Large - greater than $100k # Refer to the CIRB Charter for approvers of each tier.
Non-Network Distribution	This relates to any capital expenditure not directly related to the network. For example building a new fence at Burwood depot, service provider fleet purchases etc.

5.4.4 Non CIRB Direct Capital Expenditure Controls

This category of capital expenditure is governed by the budget that is allocated each financial year.

Capex Category	Definition
Non-Network Other	This relates to work on non-network assets paid directly by UE. It includes: • In house fleet purchases, accommodation fit out and • Miscellaneous non-network capital expenditure.

5.4.5 IT Executive Forum Capital Expenditure Controls

This category of IT capital expenditure is governed by the budget that is allocated each financial year. The following controls apply:

Capex Category	Definition
IT Executive Forum	All projects over $500k have a business case and projects below this have a decision paper written and approved. • Capital expenditure below $250k is approved by the Head of Information Technology • The General Manager Customer & Technology approves to up $500k • The General Manager Customer & Technology also approves amounts up

	to $1m, however if expenditure is between $500k and $1m, it is presented to the IT Executive Forum (ITEF) for noting • The ITEF approves expenditure above $1m. The ITEF is the IT equivalent of the CIRB and consists primarily of executive membership.

5.5 Capital Work in Progress

At any time, United Energy is involved in the construction of capital projects. Expenditure incurred in relation to these projects is recorded in one and/or two Work in Progress (WIP) general ledger accounts, tangible and intangible WIP. The expenditure is recorded against capital projects in SAP (via the use of a WBS), until the asset(s) under the project are in the location and condition necessary for them to be capable of operating in the manner intended by management i.e. physically complete.

As tangible assets are required to be classified in the balance sheet as part of PP&E and intangible asset are required to be classified in the balance sheet as an intangible, it is necessary for all capital projects to be established in SAP with separate WBS projects for their tangible and intangible components. This requirement is most commonly required for IS projects where hardware is purchased and software is either purchased and/or developed in-house. It is therefore necessary to also assign the correct tangible or intangible WBS element to all expenditure under the project.

A project is considered complete when the asset(s) are in the location and condition necessary for them to be capable of operating in the manner intended by management. When a project is complete, the value of capital accumulated in WIP must be transferred to final, depreciating or amortising assets in a timely manner.

There may be projects where there is a difference between physical completion and financial completion of a project.

Physical completion means the asset(s) are in the location and condition necessary for them to be capable of operating in the manner intended by management. For intangible projects, this means the software has gone live and is in production i.e. the 'go-live' date.

Financial completion means the project is physically complete and also all expected expenditure incurred on the project has been charged to the project.

There can be significant time differences on major and even minor projects between physical and financial completeness. It is not uncommon for differences of nine to 12 months.

Projects must be cleared from WIP:

(a) When the project is first considered to be physically complete
(b) Then each month thereafter when further expenditure has been incurred on the physically complete project.

When the last costs have been incurred on the project, the final transfer from WIP should be processed and the capital project closed.

It is the responsibility of IT, service providers and other departments within UE to review WIP. The Management Accountant of each area must provide the Fixed Asset Accountant evidence of the review on a three monthly basis via email, completed within four weeks of each quarter end. The UE WIP KPI should be referenced to form the basis of the review.

The Fixed Asset Accountant is responsible for reporting non-compliance with this policy to their manager.

5.6 Intangible Expenditure

Intangible project expenditure can be capitalised where it meets the definition and recognition criteria for a tangible asset under AASB 116 *Property, Plant and Equipment* or for an intangible asset under AASB 138 *Intangible Assets*. Information Technology hardware is a tangible asset, falling under AASB 116 while software and deferred expenditure is considered an intangible asset, falling under AASB 138.

The ability to capitalise intangible expenditure under AASB 138 is a two step process.[7]

The first step is for the expenditure to meet the identifiability criterion[8].

(a) [the item] is separable, i.e. is capable of being separated or divided from the entity and sold, transferred, licensed, rented or exchanged, either individually or together with a related contract, identifiable asset or liability, regardless of whether the entity intends to do so; or
(b) [the item] arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

The second step is for the expenditure to meet the recognition criteria[9]:

(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and
(b) the *cost* of the asset can be measured reliably.

5.6.1 Internally Generated

Internally generated intangible assets must be classified into either a research phase or a development phase.

(a) *Research* is original and planned investigation undertaken with the prospect of gaining new scientific or technical knowledge and understanding.[10] In the research phase of an internal project, an entity cannot demonstrate that an intangible asset exists that will generate probable future economic benefits so the expenditure is expensed when it is incurred.[11] Examples of research activities are[12]:

   i. activities aimed at obtaining new knowledge
   ii. the search for, evaluation and final selection of, applications of research findings or other knowledge

[7] AASB 138, paragraph 18

[8] AASB 138, paragraph 12(a) & 12(b)

[9] AASB 138, paragraph 21 (a) & 21(b)

[10] AASB 138, paragraph 8

[11] AASB 138, paragraphs 54 & 55

[12] AASB 138, paragraph 56

iii. the search for alternatives for materials, devices, products, processes, systems or services; and
iv. the formulation, design, evaluation and final selection of possible alternatives for new or improved materials, devices, products, processes, systems or services.

An example of the research phase would be activities completed prior to the development of a business case.

(b) *Development* is the application of research findings or other knowledge to a plan or design for the production of new or substantially improved materials, devices, products, processes, systems or services before the start of commercial production or use.[13] In the development phase of an internal project, an entity can, in some instances, identify an intangible asset and demonstrate that the asset will generate probable future economic benefits. This is because the development phase of a project is further advanced than the research phase.[14] Examples of development activities are:[15]
   i. the design, construction and testing of pre-production or pre-use prototypes and models
   ii. the design of tools, jigs, moulds and dies involving new technology
   iii. the design, construction and operation of a pilot plant that is not of a scale economically feasible for commercial production; and
   iv. the design, construction and testing of a chosen alternative for new or improved materials, devices, products, processes, systems or services.

Expenditure relating to the development phase may be capitalised if the entity can demonstrate **all** of the following:[16]

(a) the technical feasibility of completing the intangible asset so that it will be available for use or sale
(b) its intention to complete the intangible asset and use or sell it
(c) its ability to use or sell the intangible asset
(d) how the intangible asset will generate probable future economic benefits. Among other things, the entity can demonstrate the existence of a market for the output of the intangible asset or the intangible asset itself or, if it is to be used internally, the usefulness of the intangible asset
(e) the availability of adequate technical, financial and other resources to complete the development and to use or sell the intangible asset; and
(f) its ability to measure reliably the expenditure attributable to the intangible asset during its development.

5.6.2 Information Services Expenditure Classification

The following are examples of Information Services expenditure reflecting scenarios where the expenditure may be either capitalised or expensed.

- Hardware maintenance support incurred at the same time as the initial capitalisation of the

[13] AASB 138, paragraph 8

[14] AASB 138, paragraph 58

[15] AASB 138, paragraph 59

[16] AASB 138, paragraph 57

hardware. This support is typically for a period between 12 months and three years. United Energy capitalise the expenditure of this support against the asset as it is deemed to be necessarily incurred in bringing the asset into use.

- Hardware maintenance support incurred subsequent to the initial capitalisation of the hardware. This is typically support for a 12 month period. United Energy do not capitalise this expenditure. There are no future economic benefits to United Energy beyond a 12 month period so the expenditure cannot be considered to be capital in nature. Such expenditure may be initially classified in the balance sheet as a prepayment and recognised as an expense in the profit and loss over the 12 months of the maintenance period.

- Software maintenance support incurred at the same time as the initial purchase of the software. This support is typically for a period of 12 months. United Energy capitalise the expenditure of this support against the asset as it is deemed to be necessarily incurred in bringing the asset into use.

- Software maintenance support incurred subsequent to the initial capitalisation of the software. This is treated the same as hardware maintenance support incurred subsequent to the initial capitalisation of the hardware.

- Software licence fees. If the licence is for a 12 month period United Energy do not capitalise this expenditure. If the licence is for a period beyond 12 months it may be capitalised and amortised over the shorter of the period of the license or United Energy's useful life for software.

5.6.2.1 Exception

The exception to the above is where expenditure that would otherwise not be allowed to be capitalised is necessarily incurred in bringing the asset into the condition necessary for use. Such expenditure ceases to be capitalised when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management.

This means that expenditure on items such as 12 month hardware and software maintenance may be capitalised up to the 'go-live' date of the project as part of the overall software asset(s) capitalised for the project. After the 'go-live' date any annual software maintenance cannot be capitalised and must be treated as outlined above.

5.7 Overhead Allocation

Expenditure can only be capitalised to a project where the underlying asset is clearly identifiable. This means that any overhead expenditure may only be capitalised if it can be directly attributable to an underlying asset or a group of underlying assets. As a result of this, all capitalised overhead must be allocated to the individual capital project(s) to which it relates as opposed to accumulating all overhead into one capital project. If the overhead expenditure cannot be allocated to an appropriate individual project(s), the overhead expenditure must be expensed when incurred.

As an example the Capital Project Estimator labour time may be included as part of capitalised overhead attributable to a group of projects in any given month.

In some instances it may be deemed that a portion of an employee's labour cost may be directly attributable to a project(s). In these circumstances the capital portion of the project related expenditure may be capitalised to a group of projects in any given month.

5.8 Allocation of Assets between Entities

One physical asset can only be owned by one company. In some cases the physical asset may only be a part, but the part must be a recognisable separate component. This means that with the exception of the below, there can be no percentage allocation of an individual tangible asset between United Energy and Multinet Gas or any other entity.

If a percentage allocation is required, the value for each individual tangible asset must still be 100% allocated to one entity but the apportionment can be achieved by assigning individual assets between the two entities. For example if two vehicles were purchased, with a 50% allocation to United Energy and a 50% allocation to Multinet Gas, United Energy should be charged with the value of one vehicle and Multinet Gas charged with the value of the other vehicle. This means United Energy would own 100% of one vehicle rather than owning 50% of two vehicles.

Where the development of software is unique and for the sole benefit of only one business, no issue arises with regard to financial allocation of capital expenditure. Where the development of software is for the benefit of multiple business, each business will receive an asset on the basis of either their financial contribution to the total project expenditure or based on their intended use of the software e.g. user based. The basis for the allocation should be detailed in the business case.

5.8.1 Exception

Shared assets are allowed where there is an agreement covering separation[17]. E.g. assets subject to the Joint Business Agreement Term Sheet. Such assets include IT Services, IT Assets, IT Projects and accommodation fit-out capital expenditure.

5.9 Spares

United Energy keep two types of spares, Major Spares which are capitalised and Routine Spares which are expensed.

"Spare parts and servicing equipment are usually carried as inventory and recognised in profit or loss as consumed. However, major spare parts and stand-by equipment qualify as property, plant and equipment when an entity expects to use them during more than one period. Similarly, if the spare parts and servicing equipment can be used only in connection with an item of property, plant and equipment, they are accounted for as property, plant and equipment."[18]

The business units are responsible for maintaining adequate inventory control for all spares.

5.9.1 Major Spares

Major Spares are held to enable timely restoration of failed equipment that requires long procurement lead times. These are also sometimes referred to as strategic or critical spares. Examples include transformers, switchgear and HV circuit breakers. Major spare parts are carried at cost and are usually located at depots and zone substations. They:

[17] As per email from David Strang 24 December 2012 at 11:47am

[18] AASB116, paragraph 8

- have a low turnover
- typically have a serial number for unique identification and tracking in SAP
- are not a consumable i.e. are capitalised
- typically have a long lead delivery time or construction timeframe
- may never be used over the life of the plant
- are often held due to the adverse impact on the business if the spare part was unavailable.

Major spares are to be accounted for as part of property, plant and equipment. The major spares should be held in the asset register against the appropriate asset class for the spare. Major spares will not be held in an asset class of their own. E.g. transformer spares will be held against the transformer fixed asset class.

5.9.2 Routine Spares

Routine materials and supplies (consumables) - typically have a high turnover rate and are required at regular intervals. Typically these may be o-rings, gaskets, contacts, etc. These supplies are ordered by the Service Provider based on the inventory Min/Max trigger levels.

Due to the nature of routine materials and supplies these are classified for accounting purposes as inventory and expensed when consumed.

5.10 Depreciation

Depreciation is the systematic allocation of the cost of a tangible asset over its useful life.

Land is not depreciated as it is assumed to last indefinitely.

Buildings, machinery, equipment, furniture, fixtures, computers, cars, and trucks are examples of assets that will **last for more than one year**, but will not last indefinitely. During each accounting period a portion of the cost of these assets is being used up. The portion being used up is reported as depreciation expense on the income statement. In effect depreciation is the transfer of a portion of the asset's cost from the balance sheet to the income statement during each year of the asset's life.

A fundamental accounting concept is the matching principle. This principle requires a business to match expenses with related income in order to report a company's profitability during a specified time interval. For tangible assets this is done by depreciation.

This principle requires that the asset's cost be allocated to depreciation expense over the life of the asset. In effect the cost of the asset is divided up with some of the cost being reported on each of the income statements issued during the life of the asset. By assigning a portion of the asset's cost to various income statements, the business is matching a portion of the asset's cost with each period in which the asset is used.

5.11 Amortisation

Amortisation is the systematic allocation of the cost of an intangible asset over its useful life. In all other respects the explanation for amortisation is the same as the explanation for depreciation.

5.12 Depreciation / Amortisation Start & Finish

Depreciation and amortisation of an asset should commence when an asset is available for use, that is, when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. [19] Taking this date into account, **United Energy commences depreciation from the first day of the next month.**

Depreciation for major spares will commence from the first day of the next month that the spare is available for use. Although the major spare may not be in the location and condition necessary (installed) for use (or may never be used) the spare should be depreciated over time due to the risk of obsolesce or technology change, reflecting general deterioration which means there is a decline in future economic benefit.

Depreciation and amortisation does not cease when an asset becomes idle or removed from active use, unless the asset is fully depreciated.

Depreciation and amortisation ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is retired, subject to materiality.[20]

The amount of depreciation or amortisation charged against an asset in the month of disposal is based on the asset value date used on the asset retirement:

Asset value date used	Amount of depreciation or amortisation charge in the month of disposal
Between the 1st and the 15th day of the month	None
From the 16th day to the end of the month	A full month

5.13 Method of Depreciation and Amortisation

For tangible assets a variety of depreciation methods can be used to allocate the depreciable amount of an asset on a systematic basis over its useful life. These methods include the straight-line method, the diminishing balance method and the units of production method. [21]

For intangible assets the amortisation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. If that pattern cannot be determined reliably, the straight-line method shall be used.[22]

United Energy always uses a straight line method of depreciation and amortisation for accounting purposes.

Where an asset's useful life is changed during the life of the asset, depreciation or amortisation is

[19] AASB 116, paragraph 55

[20] AASB 116, paragraph 55 & AASB 138 paragraph 97

[21] AASB 116, paragraph 62

[22] AASB 138, paragraph 97

then allocated using a straight line method based on the remaining life of the asset.

5.14 Useful Life

Useful life is the period over which an asset is expected to be available for use by an entity[23].

The estimation of the useful life of the asset is a matter of ***judgement*** based on the experience of the entity with similar assets.[24] The useful life should be determined taking into account the following factors:

Physical life	This requires an estimate of the period of time the asset is expected to be used. It is usually an outer limit of an asset's effective life.
Engineering information	An analysis of engineering information and manufacturer's specification. The life of a new asset may differ from that achieved in the past due to advances in technology, different materials, intensity of use and the level of repairs and maintenance.
Industry norm	The useful life used by other similar business for the same asset obtained via sources such as the internet, regulatory information or Australian Taxation Office useful lives
Intensity of use	The intensity of use can have a direct impact on the asset's effective life.
Repairs and maintenance	The effective life of an asset may end when it is no longer economic to maintain it, even though it may be possible to do so.
Renewals	The estimate of when the asset will be wholly or substantially physically replaced.
Lease periods	Assets such as fixtures and fittings in leased premises should be depreciated over the shorter of their estimated useful life or the lease term.
Obsolescence	Can occur due to a number of factors including technical, regulatory or environmental

Normally the useful life adopted by an asset is the default useful life assigned against the fixed asset class the asset is held against in the fixed asset module of SAP.

The reason for the actual useful life adopted as the default useful life on an asset class must be documented and approved by the Fixed Asset Accountant's manager.

The useful life may differ from the default life for individual assets if, after taking into account the factors above, it is more appropriate to adopt a different useful life. Where a different useful life is adopted the reason for the useful life should be documented in the long text description field against the asset on the fixed asset register. The Fixed Asset Accountant is responsible for making such decisions. If the individual asset's life varies from the asset class default and the acquisition cost is:

- below $200k no further authorisation is required for the use of the different useful life
- above $200k the Fixed Asset Accountant should recommend the different useful life and is required to obtain authorisation from the Fixed Asset Accountant's manager.

[23] AASB 116, paragraph 6

[24] AASB116, paragraph 57

In some cases it is appropriate to adopt a remaining life to an asset. For example IT disk drives fit within an enterprise storage box/frame. Upon purchase of a frame, the life assigned to the drives held within the frame should be the same as the life of the frame. If additional disk drives, held within the same frame, are added at a later date, the life to assign to the additional drive should be that of the remaining life of the frame. Where a remaining life is adopted no authorisation for the adoption of the remaining life is required.

Some assets are subject to continuous improvement such as SAP software enhancements. Where this occurs, such improvements may adopt a useful life from the time of the improvement implementation recorded in the fixed asset register in calendar year annual blocks, rather than adopting a remaining life from the initial implementation.

Land and Work In Progress assets are not depreciated or amortised.

5.15 Retirement

Retiring an asset means removing it from United Energy's balance sheet i.e. derecognising the asset. This occurs upon disposal or when no future economic benefits are expected from its use or disposal.

Where an asset is no longer contributing future economic benefit to the business, the asset must be retired from the fixed asset register. This may be at a different time from the physical disposal of the asset for tangible assets. E.g. a motor vehicle will no longer be in use when it has been sent to auction but there may be a delay of weeks before the auction occurs, the proceeds from the auction are received and therefore before the retirement can be processed.

The most common type of retirement is the scrapping of a network asset (e.g. a pole) where no proceeds are received from its disposal. Other examples where an asset retirement is required include where assets are lost, stolen, damaged, sold, traded-in or removed from service with no intention to be reinstalled or written off as a result of an asset register review (refer Annex C).

Where an asset is removed from service and is cannibalised for spare parts, the asset is unlikely to contribute any material future economic benefit and so the asset should be retired.

Assets are not retired from the fixed asset register when their accounting written down value becomes zero. An asset that is fully depreciated and continues to be used in the business will be reported on the balance sheet at its cost along with its accumulated depreciation. No entry is required until the asset is disposed of through retirement, sale, etc.

The exception to this is for certain aged assets that are difficult to keep adequate inventory control over for accounting purposes. These are usually various low value assets grouped on the asset register under one asset number for each calendar year e.g. Miscellaneous tools and equipment. For these assets no details are kept on the fixed asset register so it will be unknown when each individual asset making up the original value is physically disposed. An annual review of the fixed asset register to identify these fully written down assets should occur and these assets retired from the fixed asset register (refer Annex C).

5.15.1 Sale

For an asset to be sold there must be proceeds. Where an asset can be sold, the amount of the proceeds requested from the purchaser of the asset should be determined taking into consideration the market value of the asset. The asking price must be inclusive of GST.

The accounting written down value is not the amount at which the asset should be sold. An asset can only be sold at the price that a buyer is prepared to pay for it. This may or may not be close to the accounting written down value.

All assets must be sold in an "as is condition" with no warranty/no guarantee/no support/buyer beware status.

In the absence of a readily available market value or the goods are not sold at arm's length then the sale must document the reasoning for the disposal price.

All sales must have a tax invoice or a recipient created tax invoice which states details of the asset. The Fixed Asset Accountant must be notified of the sale and provided with a copy of the tax invoice or the recipient created tax invoice.

Any expenses incurred in disposing of the asset should be deducted from the proceeds for the purposes of calculating the profit or loss on disposal of the asset.

Computers must have all licensed software and business information deleted before being sold or disposed. In the case of computers sold, the original operational software is to be re-installed on the machine. All trade marks or logos must be removed before handover of the asset to the buyer.

5.15.2 Other Proceeds

The Fixed Asset Accountant must be notified of the receipt of any proceeds for any retirement.

5.15.2.1 Scrap Proceeds

Under the Operational and Management Service Agreement (OMSA), any net proceeds received as a result of the disposal of United Energy assets belongs to United Energy. Net proceeds means the gross proceeds received less any costs incurred in disposing of the asset.

If the cost of disposal is greater than the gross proceeds, United Energy pay the Service Provider the difference. The difference is accounted for as opex expenditure.

Refer to the procurement policy to appoint an approved seller for scrap material.

Generally there are two types of proceeds received:

(a) Proceeds for the scrap metal value of many former miscellaneous network assets, accumulated into a skip for disposal. Once the skip is full, proceeds are received for the value of the scrap metal contained in the skip. As these proceeds are not for individually identifiable assets, the net proceeds will be accounted for as miscellaneous revenue.

(b) Proceeds for the scrap associated with the disposal of larger individually identifiable assets e.g. transformers in zone substations which contain metals and oil. In such cases the net proceeds received will be accounted for as proceeds received on the disposal of fixed assets.

All net proceeds are not to be accounted for as an offset against capital expenditure.

The AMI meter contracts allow scrap value to be kept by the contractors installing the AMI meters.

5.15.2.2 Public Lighting Proceeds

Existing public lighting is being retrofitted with sustainable public lighting by some councils. In such cases the AER annually review the distributors compensation allowed for the early retirement of the existing public lights. The compensation allowed by the AER is the proceeds on the retirement of the fixed asset.

5.15.3 Trade in

The Fixed Asset Accountant must be notified and provided with all support documentation when any asset(s) is traded in.

Any value attributed to an asset on trade in will constitute proceeds on disposal. An accounting journal will need to be processed which increases the value of the new asset.

The asset being traded in will be retired from the fixed asset register with the trade in value creating a profit or loss dependant on the written down value.

All trade in transactions must have a tax invoice or a recipient created tax invoice which states details of the asset. The asking price must be inclusive of GST.

5.16 Authorisation of the retirement of an asset

Assets held in the fixed asset registers are retired by a number of different ways.

Refer Annex A which sets out the various processes applicable to retirement of the different classes of assets.

5.17 Fixed Assets Registers

United Energy operates three fixed assets registers. These are:

a) Accounting
b) Federal Tax
c) Regulatory

The accounting and tax fixed asset registers are held in SAP.

5.17.1 Accounting Fixed Asset Register

Expenditure is capitalised in order to achieve agreed business outcomes. Assets lives are to be determined with regard to the expected effective life of the assets refer section 5.14 *Useful Life*. All assets are depreciated on a straight line basis.

5.17.2 Tax Fixed Asset Register

All items are to be capitalised on the same basis as accounting with the following exceptions:

a) All items in United Energy will be depreciated using the diminishing value method of depreciation where allowed. For new assets this is 200% of the depreciation rate based on the effective life.
b) Where legislation prescribes an effective life or a set depreciation method.
c) Any items replacing an existing asset will be claimed as a repair to the extent that it is not an

improvement or functionally different to the asset being replaced. These assets must be expended and transferred from work-in-progress within the financial year otherwise they will be capitalised as additions to the tax fixed asset register.

d) The value of the In kind contribution for assets is initially added to the tax fixed asset register but is reversed out twice yearly in December and June. This means the value of in-kind assets are not added to the tax fixed asset register.
e) Certain assets may need to be allocated to certain classes for depreciation for example low value assets or assets which form part of a project pool relating to a specific project.
f) If it is not clear how an asset should be depreciated for tax purposes this asset should be referred to the Tax Manager.

5.17.3 Regulatory Fixed Asset Register

All assets capitalised for accounting should be capitalised to the regulatory fixed assets register on a straight line basis except for the following:

a) In kind assets are not capitalised
b) Customer contributions reduce the value of the assets added
c) The value removed from the regulatory fixed asset register for asset retirements is only the value of proceeds received from the sale of assets.

The regulatory fixed asset register is not held in SAP. The information captured for accounting purposes on additions and disposals is used to complete the Excel spread sheets used to determine the regulatory fixed asset values.

6 Related policies/standards/legislation

The following policies, guidelines and manuals relate to the Fixed Asset Policy and can be read where they are specifically referred to within the Policy:

Reference	Document Name
AASB 5	Australian Accounting Standards Board Non-Current Assets Held for Sale and Discontinued Operation
AASB 102	Australian Accounting Standards Board Inventories
AASB 116	Australian Accounting Standards Board Property Plant and Equipment
AASB 117	Australian Accounting Standards Board Leases
AASB 119	Australian Accounting Standards Board Employee Benefits
AASB 123	Australian Accounting Standards Board Borrowing Costs
AASB 136	Australian Accounting Standards Board Impairment of Assets
AASB 137	Australian Accounting Standards Board Provisions Contingent Liabilities and Contingent Assets
AASB 138	Australian Accounting Standards Board Intangible Assets
AASB 1031	Australian Accounting Standards Board Materiality
ACC-002-POL	Account Reconciliations
ACC-004-POL	Posting Journals
ACC-005-POL	Materiality
ACC-006-POL	Reporting Close Policy
ACC-007-POL	Review of Financial Statements
ACC-008-POL	Consolidation Process
ACC-009-POL	Intra-Group transactions
ACC-010-POL	Identification and Recording Provisions and Accruals
ACC-072-PRO	Small Capex Procedure
ACC-073-PRO	Investment Management Procedure
APA-001-POL	Accounts Payable Policy
AUD-019-POL	Auditor Independence Policy
BUD-013-POL	Annual Budgeting Policy
COR-059-POL	Corporate Model Naming & Storing Procedure
DOA-003-POL	Delegation of Authority Policy
FOR-012-POL	Forecasting Policy
FAM-023-POL	MG Fixed Asset Policy
FAM-041-POL	Sustainable Public Lighting Reporting and Accounting

Reference	Document Name
FAM-042-PRO	Access Rights (Easements)
UE-MGH CI 001	Insurance Policy
INV-007-POL	Inventory Policy
PRO-004-POL	Procurement Policy
PRO-004-MAN	Procurement Manual
SOD-002-POL	Segregation of Duties Policy
UIG 1031	Urgent Issues Group Interpretation
	IT Project Financial Management Process

7 Implementation and Compliance

a) This policy will be implemented by Finance.

b) Any non-compliance under this policy must be reported to the Head of Financial Accounting & Controls.

c) There are a number of fixed asset controls in place to ensure the integrity of the fixed asset register. Refer Annex B.

d) There are a number of controls which effectively monitor the fixed asset register on a monthly, half yearly, annual basis and other periodic basis. Refer Annex C.

e) UE has the right to, at its absolute discretion, alter or modify this policy.

8 Document history

Version	Date	Amended By	Description of Changes
1	16-May-12		Original approved policy
2	30-Apr-14	Sue Edwards/Peter Ajani	Included procurement section Altered quarterly WIP review requirements Altered example of research phase Altered allocation of assets between entities Inserted useful life treatment for assets that are continuously improved Updated related policies/standards table Annex A– Inserted new section for ZABL retirements & minor changes to other sections

Annex A: Retirement Authorisation Process

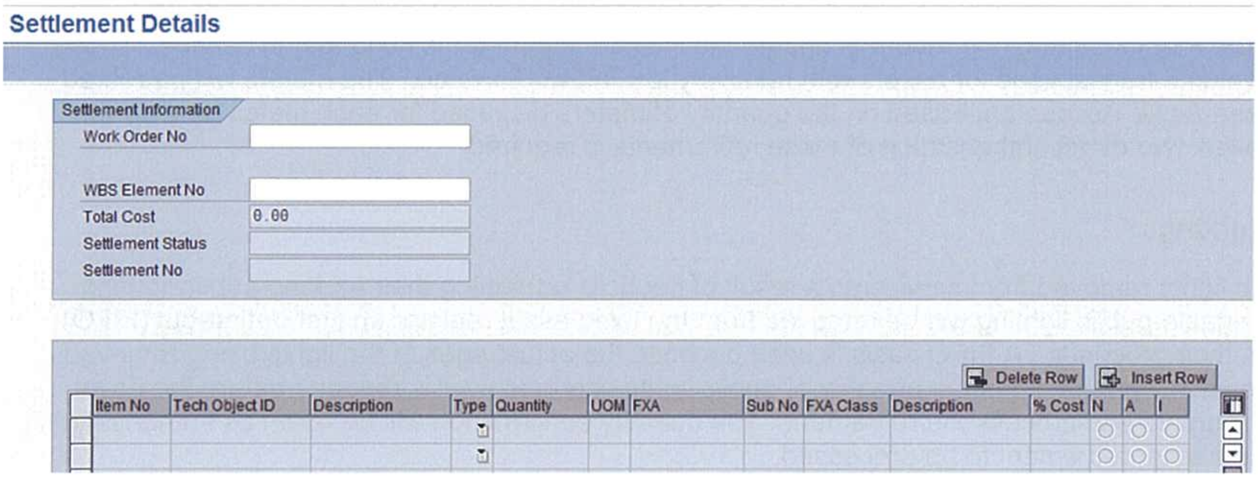
All retirements are subject to the DOA 003-POL Delegated Financial Authority Policy.

The following set outs the various retirement processes depending on the type or class of the asset.

Selected Network Assets retired using the SAP Settlement processes (ZUSDM001)

Most assets retired are network assets. The retirement of these assets is generally processed in SAP via the use of the ZUSDM001 *Settlement Details* program used by Service Providers to settle capital jobs from work-in-progress to final, depreciating assets.

In the 'Tech Object ID' field the SAP Plant Maintenance equipment record(s) is input representing the network asset worked on under the capital job. Against each row an action of N (new), A (abolish) or I (improve) is required. A fixed asset retirement will be triggered when an action of 'A' is input and the ZUSDM013 *Fixed Asset Write Offs from Settlement Screen Abolishments* program is run by the Fixed Asset Accountant.



The program has been written to contain a warning if the accounting written down value of the asset being abolished is greater than $50k.

The retirements processed via the ZUSDM013 program are reviewed for reasonableness by the Fixed Asset Accountant each month. Any material write off or assets retired that were recently capitalised and have a write off value greater than $1k are queried. Any incorrect retirements identified will be reversed by the Fixed Asset Accountant.

No direct authorisation of these ZUSDM013 retirements is required.

Selected Network Assets retired using the SAP Abolishment processes (ZABL)

In addition to the above, there are instances of network assets being retired that are not processed as part of the SAP settlement process. An example is distribution transformers. These may be removed from the network due to an upgrade. The removed transformer is sent to Stores to be reviewed to determine if it can be reused. It is therefore the personnel working in Stores that makes the abolishment decision so the personnel responsible for the upgrade works never finds out the status of the removed transformer to input into the ZUSDM001 screen.

SAP transaction ZABL *Fixed Assets Write Offs from Settlement Screen Abolishments* is used in UE SAP to process a financial write off, with the input of just the plant maintenance equipment number or functional location.

No direct authorisation of these ZABL retirements is required.

Meters

Network meters are not retired via the ZUSDM001 program.

In the Asset Owner Finance meeting held on 21st December 2009 the decision was made that all non AMI meters would not be retired when they are removed from service. This was because they are being depreciated to a maximum of the date the meter installation program is expected to be complete so for ease of administration and because the remaining life is very short, no retirements would be processed. These fixed assets will be removed from the fixed asset register when the program is complete.

Details of AMI meter retirements is sourced from the SAP Plant Maintenance module where the meter records are held. The meters have already been removed from service for various reasons when the status of the Plant Maintenance record is updated to indicate the meter is no longer in service. These are high volume transactions for assets with relatively low individual value. The meters will be retired by the Fixed Asset Accountant based on the quantity of meters disposed for each meter type, by the year installed. No direct authorisation of these retirements is required.

Public Lighting

The public lights removed from service as a result of councils retrofitting their existing public lighting with sustainable public lighting will be removed from the fixed asset register on first-in-first-out (FIFO) basis with their proceeds. A FIFO basis is used because the actual ages of the lights being removed are unknown. Confirmation of the quantity of public lights changed over is required before the Fixed Asset Accountant can process the retirement. The quantity confirmation will be taken as authorisation for the fixed asset retirement to be processed.

Retirements Arising From Fixed Asset Reviews

Retirement of fixed assets identified from reviews of the fixed asset register, refer Annex C, are required to be authorised by the Fixed Asset Accountant's manager. A list of the assets recommended for write off containing both the accounting and federal tax original acquisition cost and current written down values must be included in the detail provided by the Fixed Asset Accountant.

Motor vehicles

The Fleet and Inventory Officer is responsible for authorising all motor vehicle related disposals except where controlled by a service provider.

The Service Providers follow a historical process where the annual budget process identifies vehicles which may be nominated by them to be disposed. This budget is approved by United Energy. Once the annual budget is approved, this is the authorisation for the Service Provider to dispose of a United Energy vehicle. The net proceeds from the sale of the vehicle belong to United Energy.

Information Technology

Information Technology (IT) hardware asset disposals would normally be identified by United Energy's 3rd party service provider. They would normally make a recommendation to United Energy for the replacement or disposal of an item.

The authorisation for the retirement of an IT hardware asset is required from the Service Delivery Manager who will make a business decision on whether to proceed with the replacement or disposal.

Where the decision is made for an item to be replaced or disposed, it is the responsibility of the Service Delivery Manager to ensure:

a) All data has been erased from the hardware prior to disposal

b) The Configuration Management Database (CMDB) has been updated; and

c) The Fixed Asset Accountant has been notified of the disposal and supplied with sufficient information to ensure the item(s) disposed can be identified on the Fixed Asset Register and also informed of any proceeds attributable to the disposal.

The Fixed Asset Accountant is responsible for ensuring the assets are removed from the Fixed Asset Register after receiving written confirmation of the disposal from the Service Delivery Manager.

Other Assets

Any other asset not listed above requires the approval of the Fixed Asset Accountant's manager in order to be retired from the fixed asset register.

Annex B: Fixed Asset Controls

In SAP all network assets are capitalised to the SAP accounting fixed assets register. For Operational activities selected network assets are reflected in the plant maintenance equipment records. The SAP Plant Maintenance (PM) module contains hundreds of thousands of records for many, but not all, network assets. Each record in this module usually represents one physical network asset.

Controls for Allocation of Asset Class – Linked to PM Module

The PM module links into the fixed asset register to ensure that when the assets are recorded from an operation perspective the information flows into the fixed asset register with predefined business rules determining the correct allocation to asset classes and financial settlement.

To ensure capital is posted to the correct asset class a SAP program*'347 Validate In Service Equipment'*, was implemented. Under this 347 enhancement, table *ZUSDMTT004 – FXA Class Mapping Table – Equipment* has been established to provide some business rules to ensure a valid fixed asset number, plant maintenance category, plant maintenance class and plant maintenance object type these are assigned to all 'In Service' and 'Out of Service' plant maintenance equipment.

Below are the columns in the table with a sample of three rows:

Eq. Cat	Description	Object Type	Description	Equipment Class	Asset Class	Description	FXA Class 1 to 1 R/ship (Ind)	Inh Sup Obj	Active
S	Switchgear	SWITCH_DST	Switch Distribution	SWITCH	30142	Network Switchgear	X		X
T	Transformers	DIST_TRANS	Distrib. Transformer	TRANSFORMER_DIST	30141	Network SubsTransf	X		X
Z	Domestic (Zsub)	COOLING	Cooling	COOLING_SYSTEM	32000	Network Buildings	X		X

Controls for Allocation of Asset Class – Not in PM Module

Where an asset is not part of the PM module most assets are created manually by the Fixed Asset Accountant based on information obtained from relevant personnel. The asset numbers created are manually input on the settlement rule on the capital project and capital is transferred from work-in-progress to the final, deprecating asset(s) created. No additional check is completed on these assets as it is considered that the Fixed Asset Accountant will correctly exercise their professional judgement to ensure the assets are capitalised to the correct fixed asset class.

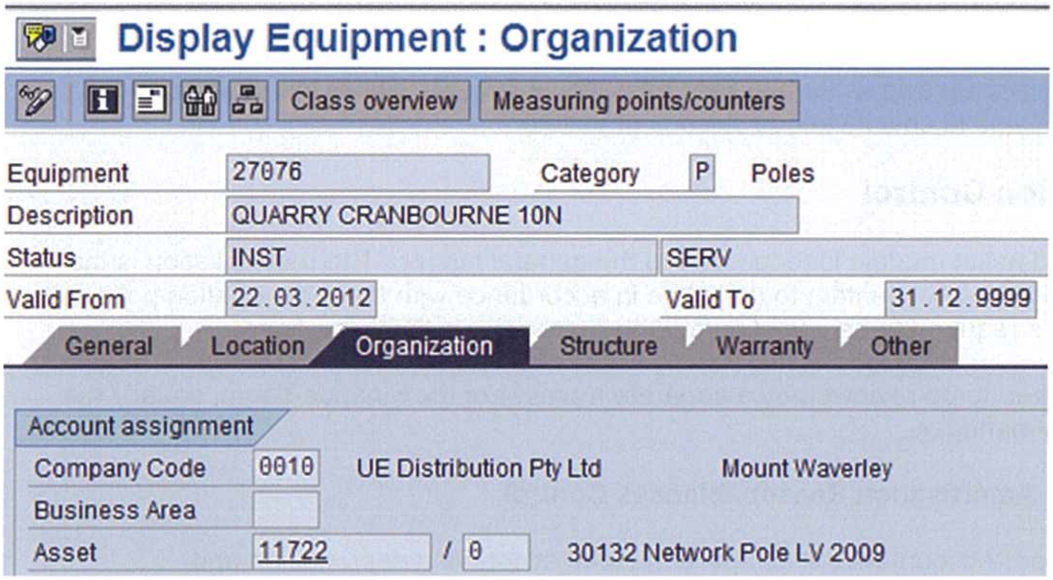
Stocktake

United Energy does not undertake periodical physical stocktakes of their tangible assets. For most of United Energy's tangible fixed assets this is impractical and would be extremely time consuming to complete. The risk of a material misstatement in the assets is low due to the nature of the assets being generally immobile and having very long lives.

An alternative to completing a physical stocktake and still obtaining some confirmation of the accuracy of the fixed asset records is to periodically reconcile the fixed asset records to sub systems that may exist for the different types of fixed assets.

The SAP Plant Maintenance (PM) module is used to link selected physical assets and the financial value for the assets.

Each record in the PM module usually represents one physical network asset. Each PM record has one field called the 'Asset' field which contains the fixed asset number which corresponds to the fixed asset register of SAP where the value of the asset is held.



Rolling reconciliations between these two modules should be completed on a cycle of five years or in accordance with the Fixed Asset Plant Maintenance Reconciliation plan.

Annex C: Monitoring Controls

The following activities are completed periodically that is monthly, half year and yearly to ensure the accuracy of the fixed asset registers. This process identifies errors and anomalies in a timely manner designed to ensure reporting packs, half yearly and annual accounts reflect accurate fixed asset information. There are additional reviews for half year and annual reviews. There are other reviews undertaken at varying intervals to check various classes of assets.

Monthly Reconciliation Control

Each month the SAP fixed asset module is reconciled to the general ledger. The reconciliation is the responsibility of the Fixed Asset Accountant to complete in accordance with the reconciliation policy. Any material variances are required to be investigated and resolved in a timely manner.

The reconciliation is required to be reviewed by a separate member of the Finance Team, usually the Fixed Asset Accountant's manager.

Monthly Depreciation & Amortisation Reasonableness Control

Each month the Fixed Asset Accountant will compare the total accounting depreciation and amortisation charged to the profit or loss against the prior months' charge. An increase or decrease in the charge per month in excess of 5% will require further investigation and the explanation documented in the Excel file used to complete this control.

Such variances are usually caused by significant additions, disposals, significant assets finishing their useful life or a change in the useful life of an asset or class of assets.

Half Yearly Depreciation & Amortisation Monitoring Control

At six monthly intervals a review of all assets on the fixed asset register is completed to ensure all assets that should be being depreciated are actually being depreciated in the accounting fixed asset module. The review is the responsibility of the Fixed Asset Accountant to complete.

These assets are identified by running SAP report ZFAL – *Fixed Asset List* for all assets and downloading the report into Excel. The download is reviewed and the following assets are removed from the list in the order below:

- All land and work-in-progress assets
- All assets with a written down value of zero
- All assets with a depreciation charge in the current year
- All assets with a depreciation start date of the next month from the date of the review

The remaining assets are assets with an accounting written down value greater than zero but have no depreciation charge in the current year when depreciation should be being charged.

A problem that exists within the fixed asset register is that new capital expenditure is allocated to very old existing assets. Typically this occurs against **underground cable** assets and **poles.** It can also occur on assets which have a depreciation charge of less than $1 per year.

1. Underground cable

The capitalisation of new capital to old assets is occurring mainly as a result of the replacement of terminations of high voltage underground cable, required only on paper cable. There is a special procedure that makes the termination of high voltage underground cable safe. The last five meters of the cable is filled with oil and over time this drains away making the cable unsafe. Where this occurs the last five meters of cable needs to be replaced, often at both ends.

A review is undertaken to specifically identify such assets. Once identified the assets are transferred from the non-depreciating asset to the current yearly grouped asset in the same asset class.

2. Poles

The capitalisation of new capital to old assets is occurring mainly as a result of the replacement of pole top structures on the poles. A pole top structure would normally only be replaced where the pole is assessed to have a minimum of a 15 year remaining life.

A review is undertaken to identify these assets. Once identified the assets life is amended so the new capital will depreciate over the next 15 years, being the minimum remaining life.

Annual Monitoring Control

Review of useful life and method

On an annual basis, at the end of each annual reporting period, the Fixed Asset Accountant will reassess the depreciation method, useful life and residual values assigned to the fixed assets.

Typically this review is completed by the Fixed Asset Accountant emailing the appropriate personnel to confirm the current useful lives and written down value of the assets and receiving a written reply on their opinion of the reasonableness of the life and written down values.

Review of fully depreciated assets

Certain aged assets are not monitored due to the volume and value of the asset. These are usually various low value assets grouped on the asset register under one asset number for each calendar year e.g. miscellaneous tools and equipment. For these assets minimal details are kept on the fixed asset register and there is no record of when the assets are physically disposed.

To address this issue, an annual review is undertaken by the Fixed Asset Accountant for these assets to identify fully written down assets. Once identified, these assets are reviewed and where appropriate these assets are retired from the fixed asset register, in accordance with section 5.15 and section 5.16.

Other Annual Reviews

Motor Vehicles

Motor vehicle asset are by their nature very mobile and have a regular change over cycle. A reconciliation of the records on the fixed asset register to Service Provider records and United Energy's records should be completed on an annual basis.

Fixture and Fitting in Leased Premises

Fixture and fittings in leased premises should contain the date of the end of the lease term in the 'Last Inventory On' field on the fixed asset module of SAP. Some leases are written with options for lease extensions. The date recorded in the 'Last Inventory On' field should be the date of the next option. The fixed asset register records for these assets should be reviewed on no less than an annual basis.

Other Periodic Reviews

Three year Reviews

The following types of assets are a valuable asset to United Energy but are quite immaterial compared to the total value of all of United Energy's tangible fixed assets:

- Office equipment
- Mobile Telephones
- Laptops and Desktops
- Printers
- Office Furniture

These assets should be reviewed at least once every three years. Unless an individual physical asset has a written down value greater than $50k, no stocktake of these items is required. For items with a written down value greater than $50k, confirmation that they are still in use in the business should be obtained by the Fixed Asset Accountant from relevant personnel.

Information Technology hardware assets should be reviewed at least once every three years by sending a list of the relevant fixed assets on the Fixed Asset Register to appropriate personnel and requesting their confirmation that the assets are still in use.

Five Year Reviews

Building assets should be reviewed at least once every five years.

Reconciliations between Plant Maintenance Module and the Fixed Asset Register should be completed on a cycle of five years or in accordance with the Fixed Asset Plant Maintenance Reconciliation plan.

Ten Years Reviews

Land assets should be reconciled to the latest United Energy's land tax assessment notice at least once every 10 years.

Appendix G: Explanation of material differences

1. Revenue and expenditure

This section addresses Sections 1.4 to 1.5 of Schedule 1 of the Annual RIN.

Table 1: Revenue

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
Standard Control	371.9	365.0	6.9	2%	*Not applicable*

Table 2: Energy sales

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
Energy Volume	7,696	7,842	(146)	-2%	*Not applicable*

Table 3: Operating and maintenance

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
Standard Control	121.9	122.5	(0.6)	-1%	*Not applicable*

Table 4: Capital expenditure

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
Standard Control	210.3	175.9	34.4	20%	*Refer to Table 5 below*

Table 5: Capital expenditure – Reasons for material difference

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
Reinforcement	35.9	35.7	0.2	1%	Not applicable
New customer connection	46.7	53.2	-6.4	-12%	Less customer connections compared to forecast.
Reliability & quality maintained	32.9	23.3	9.7	42%	Overspend for year was driven by increasing replacement of assets at their end of life; as can be seen in the network

Appendix G: Explanation of material differences

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
					performance data with assets failure the leading cause of outages in 2014
Environmental, safety & legal	67.0	44.1	22.9	52%	Catch up for underspend in previous years. Total variance for CY 2011-14 is 1.6% over the allowance.
SCADA/Network control	(0.1)	-	-0.1		Immaterial
Non network general - IT	23.7	17.5	6.2	36%	Delay in the Contents Management System and GIS upgrade projects offset by timing of expenditure on DMS upgrade, Electricity Metering System upgrade and System Rationalisation project.
Non network general - other	4.0	2.2	1.8	82%	Overspend was mainly driven by property projects, in particular the Network Control Centre, with a lesser amount attributable to trucks, offset with tools which was underspent.
Metering - Non AMI	-	-			Not applicable
Standard Control - Total Additions	**210.3**	**175.9**	**34.4**	**20%**	

2. Performance targets

This section addresses Sections 1.6 to 1.7 of Schedule 1 of the Annual RIN.

Table 6: Urban feeder parameters – SAIDI, SAIFI, MAIFI

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
SAIDI	72.550	55.085	17.465	32%	Due to an increase in asset failures and weather conditions.
SAIFI	0.949	0.899	0.050	6%	Not applicable
MAIFI	0.839	1.074	-0.235	-22%	Due to an increase in asset failures and weather conditions.

Table 7: Rural short feeder parameters – SAIDI, SAIFI, MAIFI

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
SAIDI	150.937	99.151	51.786	52%	Due to an increase in asset failures and weather conditions.
SAIFI	1.700	1.742	-0.042	-2%	Not applicable
MAIFI	2.919	2.122	0.797	38%	Due to an increase in asset failures and weather conditions.

Table 8: Customer service parameter – Telephone answering

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
Telephone answering	61.21	62.83	-1.62	-3%	Not applicable

Appendix H: Demand Management Incentive Scheme Report 2014

Note: See attached

Attachments outlined on page 17of the Demand Management Incentive Scheme Report 2014 can be provided on request.

Demand Management Incentive Scheme Report - 2014

DMIS Report

This report details outcomes of projects supported by the Demand Management Incentive Scheme.

TABLE OF CONTENTS

1 Introduction

During the 2014 calendar year, United Energy (UE) undertook three projects under the Demand Management Incentive Scheme (DMIS). These were:

- District Energy Services Scheme (DESS) Project;
- Virtual Power Plant (VPP) Project; and
- Summer Saver (Demand Response) Trial.

This report and its attachments deliver the annual reporting requirements of the DMIS for work undertaken on these projects during 2014 and documents the outcomes and learnings of each project. Further details of each project are presented below.

1.1 District Energy Services Scheme (DESS) Project

In August 2011, UE was delighted to formalise a Memorandum of Understanding (MoU) with Manningham City Council to work with the Council in providing support for jointly planned initiatives within the Doncaster Hill Smart Energy Zone[1]. Over the time, the MoU has allowed UE to provide its expertise in electricity distribution to assist the Council to explore and facilitate projects which promote sustainable energy development and demand management opportunities within the precinct. UE is supportive of and is actively engaged with the Council in its District Energy Services Scheme (DESS) project, predominantly through in-kind labour support, but also in cash support through the Demand Management Incentive Scheme Allowance (DMIA) in instances when external consulting resources were required for the development of the project. The MoU expired in 2014 and as such UE and Council have renewed the MoU for another five year term.

While the aim of the DESS project is to ultimately establish a working, commercially feasible DESS in the Doncaster Hill Smart Energy Zone to potentially defer network augmentation, the DMIA has been an essential funding source to enable the Council and UE to do the upfront work necessary to prove the concept and announce the preferred provider. Working with two qualified expert service providers to explore and establish the foundations for a suitable commercially viable model within the existing regulatory framework, has been a valuable step in the process. If proven successful, this model could form the benchmark for opportunities to develop similar schemes elsewhere around Australia.

UE has some emerging constraints within the Doncaster electricity distribution network and the convergence of these constraints with the implementation of a DESS project within the Doncaster Hill area could allow the non-network solution to defer planned network augmentations by reducing peak demand. Key to the success of achieving this objective was the development of a commercial model with two expert DESS companies identified through the Expression of Interest (EOI) and Request for Quotation (RFQ) process conducted during 2012. UE and Council shortlisted two providers, namely COFELY Australia and MSEZ Consortium from the process and both organisations have since developed comprehensive proposals that were reviewed by an independent third party AECOM during 2013.

Following the detailed review, on 13th August 2013 Council announced COFELY Australia (a subsidiary of the multinational utility company GDF SUEZ) as the preferred provider for a DESS for the Doncaster Hill Principal Activities Area. The announcement follows two years of work by Council and UE, investigating the possibility of bringing 21st century energy services to Doncaster Hill. It is unlikely that this project would have achieved this major milestone without the support of the DMIA and the close cooperation of all involved.

With COFELY Australia as the preferred provider for a DESS for Doncaster Hill, a program plan has been developed during 2014 to plan for the design and construction of the scheme. Already an MoU has been

[1] http://www.doncasterhill.com/donhilloverviewsustainability/smart-energy-zone

signed between Council and COFELY Australia to activate the first stage of the scheme being the optimisation of the Council's tri-generation plant.

Refer to Appendix 1 for further details on this project.

1.2 Virtual Power Plant (VPP) Project

In September 2013 UE submitted a request to the AER to seek indicative up-front approval to use part of the 2011-2015 allocation of Demand Management Incentive Scheme (DMIS) funding (part A) to support the development of UE's Virtual Power Plant (VPP) 50kW Residential Pilot Project.

With the price of solar photovoltaic (PV) falling dramatically and the price of battery storage forecast to decrease sharply in future years, UE was eager to explore the use of PV and battery storage technology for addressing immediate capacity shortfalls and deferring traditional network augmentation solutions on the UE network. By utilising the energy stored in batteries, VPP technology can be used by UE to shave peak load and defer augmentation projects in regions of the network where the future peak demand growth is uncertain or where peak demand is forecast to decline (potentially leading to under-utilised network assets). VPP can also be used to add capacity in regions of the network where the cost of adding capacity through traditional solutions is higher than average.

The aim of the project is to validate or otherwise, the use of a VPP to manage embedded generation and storage in a residential setting for the provision of efficient and prudent non-network augmentation.

The VPP integrates the operation of both supply and demand-side assets to meet customer demand for energy services in both the short and long-term. To match short-interval load fluctuations, the VPP is intended to make extensive and sophisticated use of information technology, advanced metering, automated control capabilities, and electricity storage. The VPP concept also treats long-term load reduction achieved through energy efficiency investments, distributed generation, and verified demand response on an equal footing with supply expansion. Thus, this approach extends the boundary of utility capacity investments through the meter, with its expanding communication and control capabilities, all the way to customer-side equipment.

In 2014 there was significant work completed as part of the stage 1 pilot. UE has now successfully installed a total of thirteen VPP units on their network. This installation was completed in July 2014, and significant testing, refinement and learnings have been established through the operations of these units.

The VPP project costs are predominantly made up of one-off setup costs, including the procurement and installation of equipment, risk assessments and equipment certification and testing. Additional contingency costs have also been allocated to allow for all the hardware to be removed at the end of the pilot and the premises returned to pre-trial condition should it be required.

Ongoing operations and lessons learned across each of the phases will be used going forward on the continuing VPP demand management projects.

Refer to Appendix 2 for further details on this project.

1.3 Summer Saver (Demand Response) Trial

Demand response seeks to incentivise the end customer to reduce their demand on a small number of peak demand days through a variety of mechanisms. These mechanisms include voluntary load reduction, utility load control, supply capacity limiting and dynamic peak pricing. Sustained reliable demand response from residential and commercial/industrial customers has been proven to be effective and efficient at managing peak demand and deferring network augmentation.

The Summer Saver Trial[2] is an investigation of how effective and efficient customer demand response is as a non-network alternative at addressing demand at peak times. The trial investigates demand management options. The outcomes of this trial will enable UE to develop a demand management model that describes the best combination of mechanisms that will result in the biggest peak demand reduction at specific locations based on customer demographics and load profiles.

UE launched the trial in February 2014 targeting 6,500 customers on four Bulleen zone substation feeders. Customers were offered $25 if they reduced their load during the UE nominated three hour event period. UE anticipated calling on average four events per summer with the customer having the opportunity to earn $100 for the summer if they participated in all events.

UE expanded the trial this summer to include 4,000 more customers in areas of the network that are likely to experience an interruption. Also, trial introduced new demand management options to existing trial members: direct load control of pool pumps and supply capacity limiting.

The majority of the costs incurred by the trial so far have been in marketing and raising awareness of the trial. Other costs include participation incentives and technology.

Refer to Appendix 3 for further details on this project.

2 Regulatory Requirement and Compliance

The AER, in its Demand Management Incentive Scheme applied to UE for the 2011-2015 regulatory period, sets certain criteria and reporting requirements for expenditure from the DMIA. These are detailed below along with a description of how UE complies with each of these requirements for each project.

2.1 DESS Project

"1. Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation."

One of the objectives of the District Energy Service Scheme is to defer the proposed network augmentation of establishing Templestowe Zone Substation (or Doncaster 4th transformer), currently detailed in UE's 2014 Distribution Annual Planning Report[3]. Solutions provided by COFELY Australia in its commercial feasibility report included opportunities to shift or reduce demand as an alternative to network augmentation.

"2. Demand management projects or programs may be:

(a) broad-based demand management projects or programs—which aim to reduce demand for standard control services across a DNSP's network, rather than at a specific point on the network. These may be projects targeted at particular network users, such as residential or commercial customers, and may include energy efficiency programs and/or

(b) peak demand management projects or programs—which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint."

The DESS aims to address specific network constraints by reducing demand on the network at the location and time of the constraint. UE's Doncaster Zone Substation supplies much of this developing area around Doncaster Hill. According to UE's Distribution Annual Planning Report 2014, Doncaster Zone Substation is

[2] http://uemg.com.au/customers/your-electricity/summer-saver-trial.aspx

[3] http://uemg.com.au/about-us/regulatory-framework/electricity-regulation/network-planning-reports.aspx

fully developed with three 20/27MVA 66/22kV transformers and supplies the areas of Doncaster, Doncaster East, Box Hill North and Templestowe including the Box Hill Central, Doncaster Hill and The Pines precincts. The maximum summer demand of the substation is already above its (N-1) rating, and the maximum demand is expected to continue to increase by at least 1MW per annum for the foreseeable future. With major commercial and high density residential developments occurring in the Doncaster Hill area, there is a need by 2020 to build a new 66/22kV 20/33MVA zone substation in Templestowe to offload the Doncaster zone substation (or to augment Doncaster Zone Substation with a 4th transformer) thereby providing additional capacity for the Doncaster Hill area. The report identifies that the DESS should help to defer the need for network augmentation beyond this time.

"3. Demand management projects or programs may be innovative, designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts."

The COFELY Australia commercial feasibility report identifies commercially viable demand management opportunities within the precinct which can be developed within the existing regulatory and planning frameworks.

"4. Recoverable projects and programs may be tariff or non-tariff based."

The DESS project is non-tariff based.

"5. Costs recovered under the DMIS:

(a) must not be recoverable under any other jurisdictional incentive scheme

(b) must not be recoverable under any other Commonwealth or State/Territory Government scheme and

(c) must not be included in forecast capital or operating expenditure approved in the distribution determination for the regulatory control period under which the DMIS applies, or under any other incentive scheme in that determination."

Costs recovered under the DMIS for the DESS project are costs incurred by UE in procuring expert consulting services. These costs have not been recovered from any other scheme. The costs do not include labour for UE and Council employees' time toward this project. This cost is absorbed by each organisation and is regarded as in-kind contribution towards the project.

"6. Expenditure under the DMIA can be in the nature of capital or operating expenditure. The AER considers that capex payments made under the DMIA could be treated as capital contributions under clause 6.21.1 of the NER and therefore not rolled into the regulatory asset base (RAB) at the start of the next regulatory control period. However the AER's decision in that regard will only be made as part of the next distribution determination."

All costs incurred by UE under the DMIS for the DESS project are classified as operating expenditure.

2.2 VPP Project

"1. Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non-network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation."

The VPP project attempts to combine the capabilities of solar PV generation and battery storage to flatten out the demand profile by charging the battery during the middle of the day when solar PV generation is at its maximum and discharging the battery during the early evening when residential demand is at its maximum. Aggregating VPP units will provide a system that can be dispatched to manage network capacity constraints.

"2. Demand management projects or programs may be:

(a) broad-based demand management projects or programs—which aim to reduce demand for standard control services across a DNSP's network, rather than at a specific point on the network. These may be projects targeted at particular network users, such as residential or commercial customers, and may include energy efficiency programs and/or

(b) peak demand management projects or programs—which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint."

The VPP aims to address specific network constraints by reducing demand on the network at the location and time of the constraint. If the VPP concept is proven, it is intended to locate such units in areas where there are identified network constraints. In the first instance, this is likely to be in areas where there are significant distribution transformer constraints by clustering the VPP units in localised areas. Ultimately the goal is to alleviate constraints higher up in the network such as at the distribution feeder or zone substation level.

"3. Demand management projects or programs may be innovative, designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts."

The VPP offers a new solution for a constrained network area, particularly where load growth is low, uncertain or is expected to plateau in future. The ability to provide incremental amounts of capacity through combining renewable generation and storage to meet the demand as it materialises could be economic against a more traditional network solution that provides significant step increases in capacity at higher cost. The VPP is intended to test this concept.

"4. Recoverable projects and programs may be tariff or non-tariff based."

The VPP project is non-tariff based.

"5. Costs recovered under the DMIS:

(a) must not be recoverable under any other jurisdictional incentive scheme

(b) must not be recoverable under any other Commonwealth or State/Territory Government scheme and

(c) must not be included in forecast capital or operating expenditure approved in the distribution determination for the regulatory control period under which the DMIS applies, or under any other incentive scheme in that determination."

Costs recovered under the DMIS for the VPP project are costs incurred by UE in procuring expert consulting services, equipment and installation services for the trial. These costs have not been recovered from any other scheme. The costs do not include labour for UE employees' time toward this project. This cost is absorbed by the organisation and is regarded as in-kind contribution towards the project.

"6. Expenditure under the DMIA can be in the nature of capital or operating expenditure. The AER considers that capex payments made under the DMIA could be treated as capital contributions under clause 6.21.1 of the NER and therefore not rolled into the regulatory asset base (RAB) at the start of the next regulatory control period. However the AER's decision in that regard will only be made as part of the next distribution determination."

All costs incurred by UE under the DMIS for the VPP project are classified as operating expenditure.

2.3 Summer Saver Trial

"1. Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non-

network alternatives, or the management of demand in some other way, rather than increasing supply through network augmentation."

The Summer Saver Trial seeks to incentivise customers to reduce their load during peak times. Customers are rewarded $25 per event for reducing their load during the UE nominated three hour event period.

Due to the late launch only 31 customers participated in the pilot, however reductions in customer load was still observed from this sample. The first event day occurred on Friday 7th February, that reached a top temperature of 37°C and saw, on average, a 30% reduction on energy consumption during the event period against their previous behaviour on a like day. The second event day, on Tuesday 11th March, was forecast to be 34+° but only reached 30°C yet an average reduction of 45% was observed compared to a like day.

It is expected that with larger numbers recruited this summer, a bigger load reduction will be seen.

"2. Demand management projects or programs may be:

(a) broad-based demand management projects or programs—which aim to reduce demand for standard control services across a DNSP's network, rather than at a specific point on the network. These may be projects targeted at particular network users, such as residential or commercial customers, and may include energy efficiency programs and/or

(b) peak demand management projects or programs—which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint."

The Summer Saver Trial seeks to address specific network constraints and is therefore targeted at customers directly impacted by those constraints. The trial targets approximately 6,500 customers on four Bulleen feeders that were close to capacity as well as about 4,000 customers in areas of the network which are likely to suffer an interruption this summer. Through the trial, UE wishes to understand if sufficient numbers of customers participate in the trial and reduce sufficient load to prevent an interruption.

"3. Demand management projects or programs may be innovative, designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts."

Demand management as a concept is not new however trialling it in a metropolitan area in Melbourne certainly is. Other DNSPs in Australia and internationally have found success with demand management in regional areas where communities display more social capital. Since UE's network is predominantly metropolitan, demand management such as demonstrated by this trial is a crucial option to be explored.

"4. Recoverable projects and programs may be tariff or non-tariff based."

The Summer Saver Trial is non-tariff based.

"5. Costs recovered under the DMIS:

(a) must not be recoverable under any other jurisdictional incentive scheme

(b) must not be recoverable under any other Commonwealth or State/Territory Government scheme and

(c) must not be included in forecast capital or operating expenditure approved in the distribution determination for the regulatory control period under which the DMIS applies, or under any other incentive scheme in that determination."

Costs recovered under the DMIS for the Summer Saver project are costs incurred by UE in marketing the trial, participation incentives and procuring technology. These costs have not been recovered from any other scheme. The costs do not include labour for UE employees' time toward this project. This cost is absorbed by the organisation and is regarded as in-kind contribution towards the project.

"6. Expenditure under the DMIA can be in the nature of capital or operating expenditure. The AER considers that capex payments made under the DMIA could be treated as capital contributions under clause 6.21.1 of the NER and therefore not rolled into the regulatory asset base (RAB) at the start of the next regulatory control period. However the AER's decision in that regard will only be made as part of the next distribution determination."

All costs incurred by UE under the DMIS for the Summer Saver Trial are classified as operating expenditure.

2.4 DMIS Reporting

The information contained in this report and its attachment appendices is suitable for public publication.

The AER requires that a DNSP's annual report must include the following for each project.

2.4.1 DESS Project

1. The total amount of the DMIA spent in the previous regulatory year, and how this amount has been calculated.

UE had $12,975 excl. GST of expenses during 2014 calendar year on activities associated with the DMIA for the DESS project comprising of:

- $12,975 excl. GST for costs associated with engaging Roberts Consulting for the DESS Stages 2 and 3 program plan. Roberts Consulting was involved in the program planning for Stage 1 of the project.

2. An explanation of each demand management project or program for which approval is sought, demonstrating compliance against the DMIA criteria in section 3.1.3 with reference to:

(a) the nature and scope of each demand management project or program

The DESS project involves formulating a suitable model for establishing a commercially viable DESS in the Doncaster Hill Smart Energy Zone area. Council and UE did not want to be prescriptive of the type of technology or solution to be implemented for the Doncaster Hill DESS, rather to have a commercially viable solution that could be established within the existing regulatory framework and meet Council's objective of reduced greenhouse gas emissions and UE's objective for network augmentation deferral through non-network solutions. The project design is such that much of the technical detail has relied largely on the specific technical and commercial expertise of the entities that were invited to respond to the RFQ and subsequently the two entities that provided the detailed study reports. The preferred provider announced by Council in 2013 offered a model that maximises the objectives of Council and UE including the ability to defer network augmentation.

(b) the aims and expectations of each demand management project or program

The Doncaster Hill Strategy was adopted by the Council in 2002 and outlined the Council's vision for a vibrant, high density and sustainable growth area for Manningham and was enacted in the Doncaster Hill Planning scheme. It is important to clarify that the Council sees its role in delivering the DESS project as being an "active facilitator" with the aim of identifying a solution that achieves the commercial objectives of developers and the planning and environmental aspirations of the Manningham community.

UE envisages a similar facilitation role for development of private and local energy grid infrastructure. However larger scale network planning has identified augmentation requirements which are likely to be able to be deferred from the range of energy management options identified by the project.

(c) the process by which each project or program was selected, including the business case for the project and consideration of any alternatives

The quest to identify a commercially feasible district based solution to address the energy needs of Doncaster Hill commenced through an Expression of Interest (EOI) process. The EOI closed on 23rd November 2011 and a number of responses were received including responses from:

- AG Coombs;
- Cogent / Origin Energy;
- Dalkia;
- GDF Suez (COFELY Australia); and

- Total Energy Solutions / Aurora Energy / Transfield Services (MSEZ consortium).

A project steering committee was established comprising of Council and UE representatives to assess the submissions. Through a formalised selection process, two respondents were invited to undertake a more detailed feasibility study through a Request for Quotation (RFQ) process, these being:

- GDF Suez (COFELY Australia); and
- Total Energy Solutions / Aurora Energy / Transfield Services (MSEZ consortium).

A DMIA budget allocation was used to contribute toward the feasibility work and this was shared equally between the two successful RFQ respondents. In responding to the EOI all respondents were made aware that there would be some requirement to invest their own resources on a venture basis to complement the DMIA funding stream. Therefore the DMIA funding did not cover the full costs incurred by the two successful providers.

In 2013, Council and UE engaged AECOM to undertake a verification review of the two study reports provided by the two study providers. The study reports were assessed on their ability to maximise the strategic objectives for the project. Based on the results of the verification review, Council announced publically on 13th August 2013 the preferred provider of the DESS for Doncaster Hill, being COFELY Australia.

During 2014, UE and Council engaged Roberts Consulting to develop a program plan for Stages 2 and 3 of the project. These stages involve securing anchor clients for the DESS, and facilitating the design and construction for the DESS.

(d) how each project or program was/is to be implemented

The DESS project is being implemented in a number of stages.

The initial stage was the establishment of a MoU between UE and Council. This was competed in August 2011 with an official signing ceremony at Council's August meeting, with speeches by UE and Council CEOs. The MoU expired in 2014 and was subsequently extended for another five years. For a copy of the renewed MoU, refer to Appendix 1.

In November 2011, Council in consultation with UE issued an EOI to the market to request suitably qualified district energy service providers to register their interest for undertaking a study to identify a technically and commercially viable model for a DESS solution specific for Doncaster Hill.

The next stage was the securing of funding through the DMIA with the UE application sent to the AER in January 2012, with an associated letter of support from Council. In March 2012, the AER responded to UE, endorsing the application.

In April 2012, Council in consultation with UE, issued an RFQ to the two shortlisted providers from the EOI process (COFELY Australia and MSEZ Consortium) to request offers for services to develop a DESS study to identify a technically and commercially viable model for a DESS solution specific for Doncaster Hill.

In July 2012 with the high quality of both proposals submitted, Council and UE decided to engage both service providers to independently undertake the commercial feasibility study, to maximise the opportunity for at least one proposed solution to be commercially viable. A developers' breakfast information session was held in July 2012 which was open by invitation to all building developers in Doncaster Hill, an important stakeholder group needed to be consulted for project viability. This session provided the opportunity for the two service providers to introduce themselves and start the consultation and negotiation process necessary to develop a commercially viable solution.

In August 2012, Roberts Evaluation consulting firm was engaged to establish the planning and evaluation framework for this project with a workshop held and a Project Monitoring and Evaluation plan developed. This plan is a living document and will be updated quarterly throughout the course of the project.

In October 2012, the two service providers presented their findings of their draft reports to Council and UE. Reports were finalised thereafter. The COFELY Australia DESS study report and the MSEZ DESS study report were included in the 2012 DMIS Report. Both reports proposed commercially viable solutions that go some way to providing network augmentation deferral.

UE in consultation with Council (and with the endorsement of the two service providers), engaged AECOM to undertake an independent verification of the two study reports. This work was completed in April 2013 with a verification report prepared for each of the two study providers.

Also in 2013 UE began to negotiate terms and conditions for a future network support agreement with the providers that will be used for developing network support services for a non-network solution to defer the planned network augmentation. The study reports together with the developed draft agreements will be assessed as non-network solutions for the Doncaster/Templestowe Supply Area Regulatory Investment Test for Distribution (RIT-D) process expected during 2016.

In August 2013, Council publically announced its preferred provider for the precinct being COFELY Australia with a media release.

In 2014 Council and COFELY Australia signed an MoU to commence the optimisation of Council's tri-generation system, an important starting point for the DESS. Further Council and UE engaged Roberts Consulting to develop the program plan for Stages 2 and 3 of the DESS which involve securing anchor clients for the scheme and the detailed design and construction of the scheme.

(e) the implementation costs of the project or program and

In 2014, costs used from the DMIA were allocated to prepare a program plan for Stages 2 and 3 of the DESS.

(f) any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions.

To date, two commercial feasibility studies have been completed and a preferred provider for the DESS announced by Council. A program plan for the establishment of the DESS has also been completed.

3. The costs of each demand management project or program:

(a) are not recoverable under any other jurisdictional incentive scheme,

(b) are not recoverable under any other state or Commonwealth government scheme, and

(c) are not included in the forecast capital or operating expenditure approved in the AER's distribution determination for the regulatory control period under which the DMIS applies, or under any other incentive scheme in that determination.

- Expenditure under the demand management incentive scheme is not eligible for recovery under any other jurisdictional incentive scheme
- Expenditure under the demand management incentive scheme is not eligible for recovery under any other state or Commonwealth government scheme
- Expenditure under the demand management incentive scheme has not been approved in the AER's distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

4. An overview of developments in relation to projects or programs completed in previous years of the regulatory control period, and of any results to date.

Not applicable.

2.4.2 VPP Project

1. The total amount of the DMIA spent in the previous regulatory year, and how this amount has been calculated.

UE had $850,672 excl. GST of expenses during the 2014 calendar year on activities associated with the DMIA for the VPP project. The costs were associated with engaging external consultants for the one-off planning of the VPP project and procurement, installation and testing of the associated equipment for the trial. These costs can be categorised as follows:

- $293,482 excl. GST for the pre-implementation study including work on predictive, economic and business modelling before commencing the pilot program.
- $580,358 excl. GST for the supply, installation and operation of VPP Units. This cost includes procurement costs (such as legal fees for development of the contract and engaging external consultants for the planning of the VPP project), installation costs (including completing factory acceptance testing of equipment before installation, the install of the equipment and audit of the installation by a licenced electrical inspector for compliance to standards) and ongoing operational expenses associated with the pilot (such as sim cards to enable remote control and continuous live monitoring of the systems by UE);
- $49,000 excl. GST for risk assessment of VPP systems, installations and operations;
- $138,400 excl GST for laboratory testing of VPP units under various climatic conditions that are likely to be experienced on the UE network;
- *of which* $210,568 excl GST of expenses incurred in early 2014 that were reported in the 2013 DMIS report have been deducted from the total reported this year.

Further costs associated with the VPP pilot project are likely to be incurred by UE in the 2015 calendar year. The costs incurred in the Stage 1 pilot are currently being used to assess the financial feasibility of implementing future VPP projects at scale.

2. An explanation of each demand management project or program for which approval is sought, demonstrating compliance against the DMIA criteria in section 3.1.3 with reference to:

(a) the nature and scope of each demand management project or program

A VPP can be defined as a cluster of grid-connected distributed generation and storage plants that are monitored and controlled by an operator for energy trading and grid benefits. When combined, the cluster can then be treated as a single power plant. For UE's VPP project we intend to use solar PV and battery storage technologies which when combined can act to reduce peak electricity demand.

(b) the aims and expectations of each demand management project or program

The aim of stage 1 of the project is to test the VPP concept and its ability to control peak demand through the dispatch of battery storage optimised against solar PV generation.

Traditional network solutions usually result in sunk capital; the resulting augmented asset cannot be easily recovered and used elsewhere if future demand falls. This project's aim is to validate or otherwise, the use of a VPP to manage embedded generation and storage in a residential setting for the provision of efficient and prudent network augmentation. The solution will be validated if it:

- Effectively avoids/defers CAPEX/OPEX requirements in a prudent and efficient manner.
- Is the most economic outcome when actual costs and benefits are known.
- Is a technically appropriate solution with appropriate mitigation of any risks.

The objectives of this project are to validate VPP as a suitable approach for managing augmentation on the UE distribution network with no adverse impacts to network reliability and safety. The VPP project aims are:

- To test the current state of the technology and its ability to scale.
- To identify the risks.
- To test and assess the level of control that can be achieved with commercially available devices currently on the market.
- To develop an understanding of the economics of the solution and validate the solution is a viable load management tool by exploring and then testing the business model(s), taking the generation, retail and distribution aspects into consideration.
- To explore and test the contractual and commercial agreements with 3rd parties and Residential Hosts (customers).

(c) the process by which each project or program was selected, including the business case for the project and consideration of any alternatives

This project proposes VPP as a solution to address peak demand issues in low voltage feeders when augmentation costs using traditional solutions are high. It is anticipated that in the future, distributed generation and storage will have application for the entire network as costs continue to fall.

(d) how each project or program was/is to be implemented

The overall VPP project has been broken into three key stages to ensure that appropriate governance over costs, risks and benefits and associated gating and review are applied at each stage, with each stage being subject to independent approval. Stage 1 (present stage) consists of a VPP system comprising between eight and fourteen installations at residential sites totalling 50kW. The installation sites will be limited to UE employees and VPP project team members' premises within the UE distribution area to manage identified risks. Stage 1 will be operated over a period of 12 to 15 months to test the economics and commercial models and understand the technology's capabilities, limitations and suitability for larger scale deployment. This stage will provide a full year of energy flow data through seasonal variations.

(e) the implementation costs of the project or program and

In September 2013 UE submitted a request to the AER to seek indicative up-front approval to use part of the 2011-2014 allocation of Demand Management Incentive Scheme (DMIS) funding (part A) to support the development of UE's Virtual Power Plant (VPP) 50kW Residential Pilot Project. This was endorsed by the AER on the 2nd October 2013. The overall VPP project stage 1 is estimated to cost $1.75M.

(f) any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions.

Given the early stages of the project, to date no peak demand reductions have been achieved.

3. The costs of each demand management project or program:

(a) are not recoverable under any other jurisdictional incentive scheme,

(b) are not recoverable under any other state or Commonwealth government scheme, and

(c) are not included in the forecast capital or operating expenditure approved in the AER's distribution determination for the regulatory control period under which the DMIS applies, or under any other incentive scheme in that determination.

- Expenditure under the demand management incentive scheme is not eligible for recovery under any other jurisdictional incentive scheme

- Expenditure under the demand management incentive scheme is not eligible for recovery under any other state or Commonwealth government scheme
- Expenditure under the demand management incentive scheme has not been approved in the AER's distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

4. An overview of developments in relation to projects or programs completed in previous years of the regulatory control period, and of any results to date.

Not applicable.

2.4.3 Summer Saver Project

1. The total amount of the DMIA spent in the previous regulatory year, and how this amount has been calculated.

UE had $51,470 excl. GST of expenses during the 2014 calendar year on activities associated with the DMIA for the Summer Saver Trial comprising of the following:

- $51,470 excl. GST for costs associated with marketing the summer saver trial, paying participation incentives and conducting market research.

2. An explanation of each demand management project or program for which approval is sought, demonstrating compliance against the DMIA criteria in section 3.1.3 with reference to:

(a) the nature and scope of each demand management project or program

This Summer Saver Trial is an investigation of how effective and efficient customer demand response is as a non-network alternative at addressing demand at peak times.

Different mechanisms of demand response can be utilised to motivate and/or incentivise customers to change their energy usage behaviour and reduce load during peak times. These include:

- Voluntary Demand Side Participation (DSP): incentivises customers to reduce/shift their load during peak times with a single-rate reward paid to those who reduce usage by any amount.
    - Rebate per kW reduced: motivates a greater reduction in load during peak times as the rebate is dependent on how much load is reduced – the more load reduced the greater the rebate.
- Direct Load Control: gives the utility more certainty in managing load by allowing the utility to manage appliances (RCAC and/or pool pump) during peak times to a known and predictable maximum.
- Critical Peak Pricing: electricity is priced significantly more during peak times to induce customers to reduce load and save money on their bill.
- Supply Capacity Limiting: sets a limit on the customers supply during peak times. This mechanism targets high users by enforcing a reasonable limit on their supply during peak times. Signing up to this option is voluntary and it is envisioned that such customers are genuinely keen to save energy and be more comparable to their neighbours.

(b) the aims and expectations of each demand management project or program

The key objectives of this trial are to investigate and assess the benefit provided to the network through:

- demand management tools:
    - investigate the take-up and impact of the three demand management mechanisms on customer load at peak times

  - incentivise customers to reduce their load during peak times via one or more demand management tool

- Informing and empowering the consumer:

  - provide consumers with the tools and information they need to take an active role in managing their consumption and to reduce energy costs and environmental impact

To this end, the trial intends to:

- investigate the take up of the different demand management mechanisms and their
- attractiveness/value to the customers managing/reducing their load
- attractiveness/value to UE in managing peak load
- investigate the value of the different demand management mechanisms compared with network solutions
- identify risks with the technology in installation and operation
- develop UE knowledge and capability in leveraging AMI benefits
- develop relationships with UE customers
- explore and test contractual and commercial agreements with 3rd parties (retailers, contractors, suppliers)

The outcomes of this trial will enable UE to develop a demand management model that describes the best combination of mechanisms that will result in the biggest peak demand reduction at specific locations based on customer demographics and load profiles.

This model will then be incorporated into business-as-usual activities to manage peak demand.

(c) the process by which each project or program was selected, including the business case for the project and consideration of any alternatives

Approximately 85% of UE's network services residential customers. This trial investigates various demand management options that can be employed by residential customers. The results of this trial will help UE define which demand management mechanisms have the biggest customer take-up and participation and yield the biggest load reductions at a given incentive value.

(d) how each project or program was/is to be implemented

UE undertakes analysis to identify trial areas that are likely to experience an interruption and could benefit from load reduction through demand management. Customers in these areas are sent letters informing them of the trial with a call for action to register via the UE website.

UE accepts registrations from customers within the trial area who have either a mobile phone or email account to receive UE event alerts.

UE sends SMS and/or email alerts to customers:

- 48 hours notification of an event day
- 24 hour notice of the event period
- And a reminder on the morning of the event day.

Following the event, UE analyses customer smart meter data to verify load reduction during the three hour event period. Successful customers are informed via email that they will be rewarded. Rewards are processed and sent within two weeks following an event.

UE undertakes further analysis of customer data to evaluate individual customer and total load reduction achieved for the event.

(e) the implementation costs of the project or program and

In 2014 the DMIA costs were spent on marketing activities that included:

- Letters mailed to customers
- Flyers dropped in letter boxes
- Advertisements in local newspapers.

Funds were also spent on market research of customers within the trial area to understand the best channels to inform customers of the trial and motivations for signing up (or not) to the trial. Research was conducted on trial members to learn about their experience on the trial and find ways of improving the trial.

(f) any identifiable benefits that have arisen from the project or program, including any off peak or peak demand reductions.

UE called two event days last summer.

The first event day occurred on Friday 7th February that reached a top temperature of 37°C and saw on average 30% reduction on energy consumption during the event period against the customer's previous behaviour on a like day.

The second event day, on Tuesday 11th March, was forecast to be 34+° but only reached 30°C yet an average reduction of 45% was observed compared to a like day.

3. The costs of each demand management project or program:

(a) are not recoverable under any other jurisdictional incentive scheme,

(b) are not recoverable under any other state or Commonwealth government scheme, and

(c) are not included in the forecast capital or operating expenditure approved in the AER's distribution determination for the regulatory control period under which the DMIS applies, or under any other incentive scheme in that determination.

- Expenditure under the demand management incentive scheme is not eligible for recovery under any other jurisdictional incentive scheme
- Expenditure under the demand management incentive scheme is not eligible for recovery under any other state or Commonwealth government scheme
- Expenditure under the demand management incentive scheme has not been approved in the AER's distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

4. An overview of developments in relation to projects or programs completed in previous years of the regulatory control period, and of any results to date.

Not applicable..

3 Attachments

3.1 Appendix 1 - DESS Project

3.1.1 Cofely Newsletter

3.1.2 United Energy / Manningham City Council MoU (5 year extension)

3.1.3 Program Plan for Stages 2 and 3

3.2 Appendix 2 – VPP Pilot Project Stage 1

3.2.1 VPP 2014 Report

3.3 Appendix 3 - Summer Saver Project

3.3.1 Customer Letter

3.3.2 Customer Registration

3.3.3 Frequently Asked Questions

3.3.4 Promotional Flyer

3.3.5 Terms and Conditions

3.3.6 UE Website Content

Appendix I: Statutory Declaration

Note: See attached

STATUTORY DECLARATION

Evidence (Miscellaneous Provisions) Act 1958, VIC

I, Hugh Gleeson, of Level 3, 6 Nexus Court, Mulgrave

In the State of Victoria

do solemnly and sincerely declare that:-

1. I am an officer, for the purposes of the *National Electricity (Victoria) Law* **(NEL)**, of United Energy Distribution Pty Ltd (ACN 064 651 029) **(United Energy)**, a regulated network service provider for the purposes of section 28D of the NEL. I am authorised by *United Energy* to make this statutory declaration as part of the response of *United Energy* to the Regulatory Information Notice dated 18 December 2013 **(Notice)**, as amended by the AER on 6 August 2014 served on *United Energy* by the Australian Energy Regulator **(AER)**.

2. The response of *United Energy* regarding the information required to be provided and to be prepared and maintained as specified by Notice, with the exception of the information specified to be audited under Appendix E to this Notice, is to the best of my information, knowledge and belief, and except where expressly stated otherwise:

   a) in accordance with the requirements of the Notice; and

   b) true and accurate.

3. Where it is not possible to provide the information required by the Notice *United Energy* has provided an estimate, or an explanation of its inability to provide the required information. Where the information provided is an estimate, *United Energy* has used its best endeavours to generate the most appropriate estimate, and has provided the AER with the basis for this estimate and reasons why it is the most appropriate estimate.

I acknowledge that this declaration is true and correct, and I make it with the understanding and belief that a person who makes a false declaration is liable to the penalties of perjury.

Declared at MULGRAVE

this 27th day of April 2015

....
Signature of person making this declaration
[to be signed in front of an authorised witness]

AUDREY WALDEGRAVE
6 Nexus Park Mulgrave Victoria 3170
An Australian Legal Practitioner
within the meaning of the
Legal Profession Act 2004 (VIC)

Before me,

....
Signature of Authorised Witness

The authorised witness must print or stamp his or her name, address and title under section 107A of the *Evidence (Miscellaneous Provisions) Act 1958* (as of 1 January 2010), (previously *Evidence Act 1958*), (eg. Justice of the Peace, Pharmacist, Police Officer, Court Registrar, Bank Manager, Medical Practitioner, Dentist)

Appendix J: Audit reports

Note: See attached

[To be provided following Board Meeting 28th April]

Ernst & Young
8 Exhibition Street
Melbourne VIC 3000 Australia
GPO Box 67 Melbourne VIC 3001

Tel: +61 3 9288 8000
Fax: +61 3 8650 7777
ey.com/au

Independent auditor's report to the directors of United Energy Distribution Pty Ltd

We have audited the Financial Information within tables 1a, 2, 3a, 3b, 5, 6a, 6b, 8a, 8b, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28 and 29 in the data template entitled "United Energy Annual RIN 2014 – Financial" (the "Financial Information") attached, which has been prepared in accordance with United Energy Distribution Pty Ltd's Basis of Preparation (the "Basis of Preparation") in response to the Annual Regulatory Information Notice ("the Notice") issued by the Australian Energy Regulator on 6 August 2014, for the regulatory year ended 31 December 2014. In accordance with the requirements of the Notice, information presented in the Financial Information before this date range has not been subject to audit.

In addition, we have audited the compliance of the Basis of Preparation as it relates to the Financial Information, with the requirements of the Notice and the Principles and Requirements in Appendix E of the Notice, for the regulatory year ending 31 December 2014.

The Australian Energy Regulator requires the Financial Information and the accompanying Basis of Preparation for the performance of a function conferred on it under Division 4 of Part 3 of the *National Electricity (Victoria) Law*, namely conducting various benchmarking exercises as outlined in the Regulatory Information Notice issued to United Energy Distribution Pty Ltd on 6 August 2014.

Management's Responsibility for the Data Template and Basis of Preparation

Management is responsible for the preparation and fair presentation of the Financial Information in accordance with the requirements of the Notice and United Energy Distribution Pty Ltd's Basis of Preparation, and for such internal controls as management determines are necessary to enable the preparation of the Financial Information that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the Financial Information based on our audit. We conducted our audit in accordance with Australian Auditing Standards. Those standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance about whether the Financial Information is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Financial Information. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the Financial Information, whether due to fraud or error. In making those risk assessments, we consider internal controls relevant to the entity's preparation of the Financial Information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal controls.

Our responsibility is also to express a conclusion on compliance, in all material respects, of the Basis of Preparation with the requirements of the Notice that relates to the Financial Information. Our audit has been conducted in accordance with applicable Standards on Assurance Engagements (ASAE 3100 Compliance Engagements). Our procedures have been undertaken to form a conclusion as to whether the Basis of Preparation has complied, in all material respects, with the Notice.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Independence

In conducting our audit we have complied with the independence requirements of the Australian professional accounting bodies.

Opinion

In our opinion, the Financial Information of United Energy Distribution Pty Ltd for the year ended 31 December 2014 has been prepared, in all material respects, in accordance with the requirements of the Notice and United Energy Distribution Pty Ltd's Basis of Preparation. In addition, the Basis of Preparation as it relates to Financial Information has complied, in all material respects, with the requirements of the Notice and the Principles and Requirements in Appendix E of the Notice.

Basis of Accounting

Without modifying our opinion, we draw attention to the Basis of Preparation which describes the general approach to collecting and preparing information. The Financial Information is prepared to assist United Energy Distribution Pty Ltd to meet the requirements of UED Regulatory Information Notice issued by the Australian Energy Regulator. As a result, the Financial Information may not be suitable for another purpose. Our report is intended solely for United Energy Distribution Pty Ltd and the Australian Energy Regulator and should not be distributed to any other parties.

Ernst & Young

Ernst & Young
Melbourne
28 April 2015

Ernst & Young
8 Exhibition Street
Melbourne VIC 3000 Australia
GPO Box 67 Melbourne VIC 3001

Tel: +61 3 9288 8000
Fax: +61 3 8650 7777
ey.com/au

Independent auditor's Report to the members of United Energy Distribution Pty Ltd

We have audited the Non-Financial Information within tables 1a, 1b, 1c, 1e, and 1f in the data template entitled "United Energy Annual RIN 2014 – Non-Financial" (the "Non-Financial Information") attached, which has been prepared in accordance with United Energy Distribution Pty Ltd's Basis of Preparation (the "Basis of Preparation") in response to the Annual Regulatory Information Notice ("the Notice") issued by the Australian Energy Regulator on 6 August 2014, for the regulatory year ended 31 December 2014. In accordance with the requirements of the Notice, information presented in the Non-Financial Information before this date range has not been subject to audit.

In addition, we have audited the compliance of the Basis of Preparation as it relates to Non-Financial Information, with the requirements of the Notice and the Principles and Requirements in Appendix E of the Notice, for the regulatory year ending 31 December 2014.

The Australian Energy Regulator requires the Non-Financial Information and the accompanying Basis of Preparation for the performance of a function conferred on it under Division 4 of Part 3 of the *National Electricity (Victoria) Law*, namely conducting various benchmarking exercises as outlined in the Regulatory Information Notice issued to United Energy Distribution Pty Ltd on 6 August 2014.

Management's Responsibility for the Data Template and Basis of Preparation

Management is responsible for the preparation and fair presentation of the Non-Financial Information in accordance with the requirements of the Notice and United Energy Distribution Pty Ltd's Basis of Preparation, and for such internal controls as management determines are necessary to enable the preparation of the Non-Financial Information that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the Non-Financial Information based on our audit. We conducted our audit in accordance with Australian Auditing Standards. Those standards require that we comply with relevant ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Non-Financial Information is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Non-Financial Information. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the Non-Financial Information, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the entity's preparation of the Non-Financial Information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal controls.

Our responsibility is also to express a conclusion on compliance, in all material respects, of the Basis of Preparation with the requirements of the Notice that relates to Actual Financial Information. Our audit has been conducted in accordance with applicable Standards on Assurance Engagements (ASAE 3100 Compliance Engagements). Our procedures have been undertaken to form a conclusion as to whether the Basis of Preparation has complied, in all material respects, with the Notice.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Independence

In conducting our audit we have met the independence requirements of the Australian professional accounting bodies.

Opinion

In our opinion, the Non-Financial Information of United Energy Distribution Pty Ltd for the year ended 31 December 2014 presents fairly, in all material respects, in accordance with the requirements of the Notice and United Energy Distribution Pty Ltd's Basis of Preparation. In addition, the Basis of Preparation as it relates to Non-Financial Information has complied, in all material respects, with the requirements of the Notice and the Principles and Requirements in Appendix E of the Notice.

Basis of Accounting and Restriction on Distribution

Without modifying our opinion, we draw attention to the Basis of Preparation, which describes the general approach to collecting and preparing information. The Non-Financial Information is prepared to assist United Energy Distribution Pty Ltd to meet the requirements of the Notice. As a result, the Non-Financial Information may not be suitable for another purpose. Our report is intended solely for United Energy Distribution Pty Ltd and the Australian Energy Regulator and should not be distributed to any other parties.

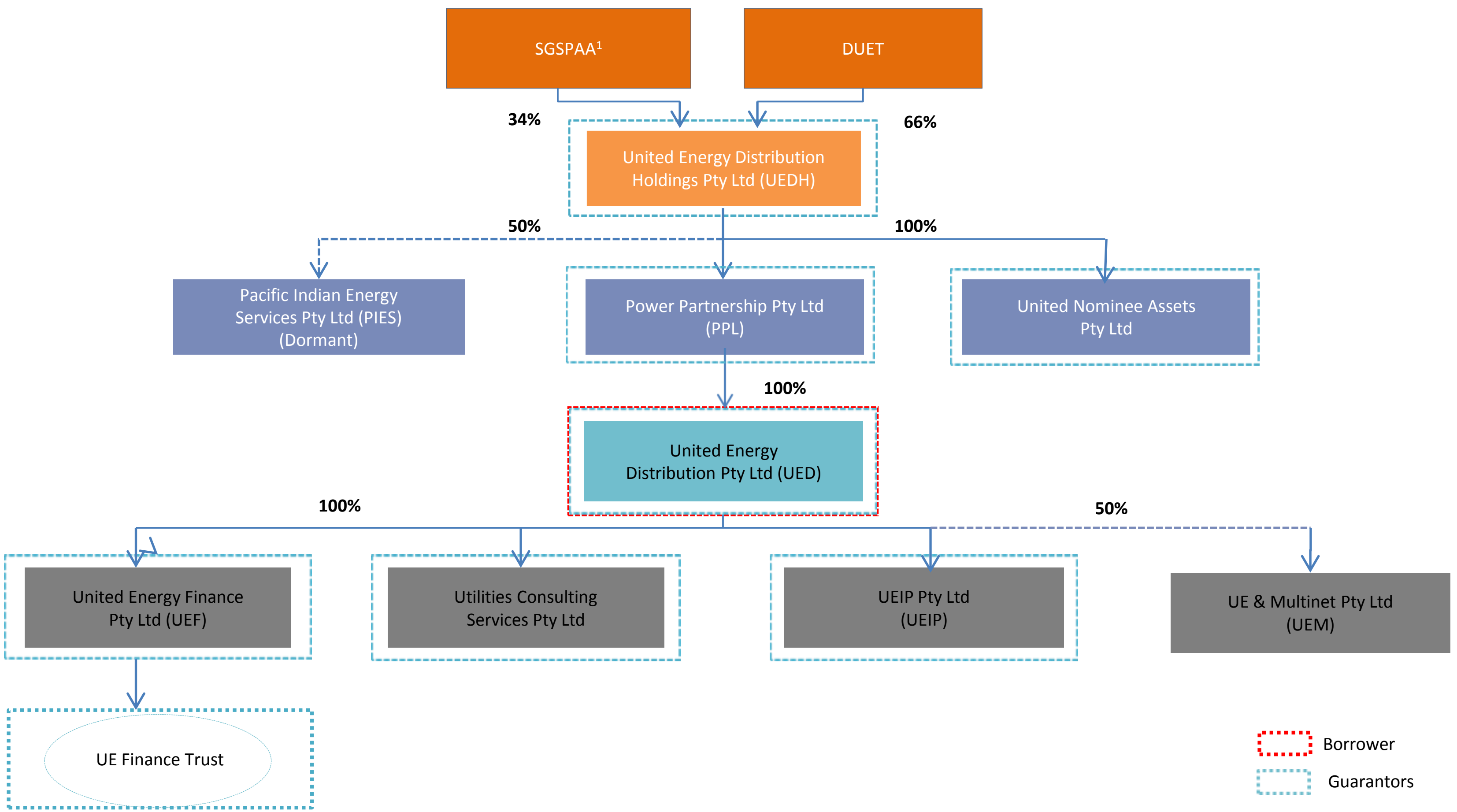
Ernst & Young

Ernst & Young
Melbourne
28 April 2015

Appendix K: Charts

Note: See attached

United Energy Corporate Structure



1 SPIAA changed its name to SGSP (Australia) Assets Pty Limited on 3rd January 2014

Organisation Structure

18 March 2015

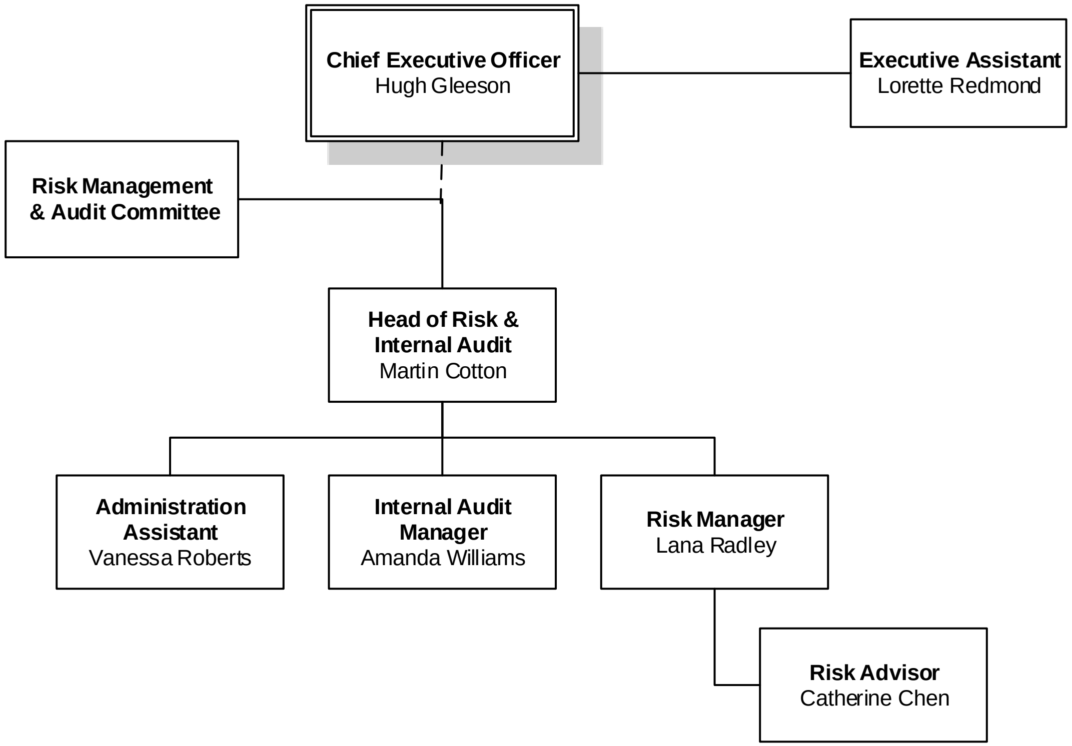
Head Count: 313

UNITED ENERGY

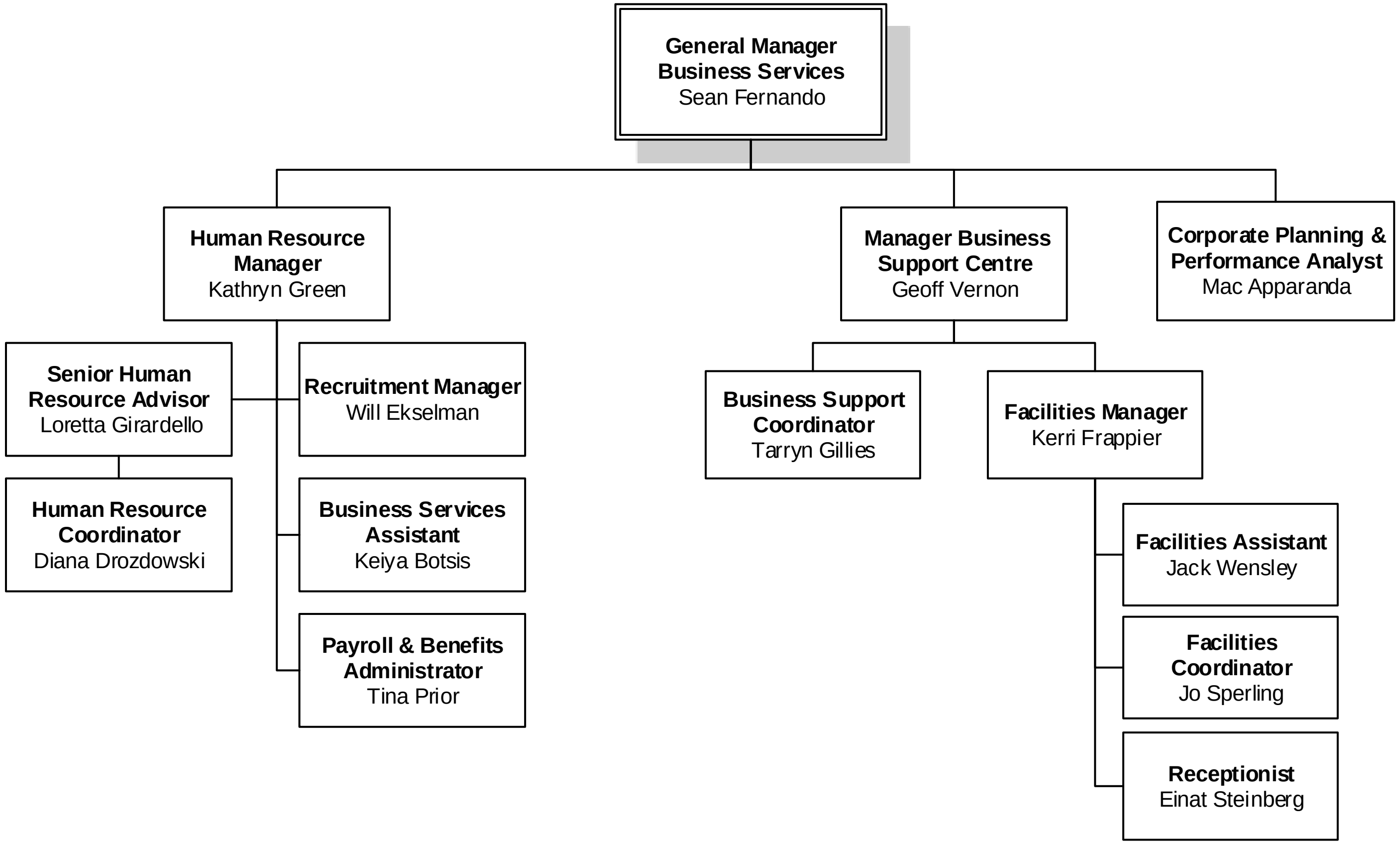
Multinet GAS

- **Chief Executive Officer**
  Hugh Gleeson
  - **Business Services**
    Sean Fernando
  - **Regulatory Services & Corporate Affairs**
    Andrew Schille
  - **Finance**
    Anne Hayes
  - **Customer and Technology**
    Alistair Legge
  - **Commercial & Legal**
    Rob Sarafian
  - **Service Delivery**
    Michael Thomson
  - **Gas Network**
    Mark Beech
  - **Electricity Network**
    Mark Clarke

CEO’s Office



Head Count: 7



Head Count: 13

Electricity Network

UNITED ENERGY

Multinet GAS

- **General Manager Networks (Electricity)** Mark Clarke
  - **Personal Assistant** Simone Azzopardi
  - **Network Strategy Manager** Gregory Hannan
    - **Strategic Commercial Analyst** Leigh Martin
  - **Network Risk, Safety & Compliance Manager** Mike Tshaikiwsky
    - **Technical Compliance Engineer** Mike Hodgkinson
    - **Technical Compliance Officer** Anthony Estrada
  - **Capex, Opex & Special Projects Manager** David Volf
    - **Strategic Project Manager** Ken Church
    - **Works Program Analyst** Kenneth Rudan
  - **Network Planning Manager** Rodney Bray
    - **Future Networks Engineer** Sharon Tissai-Krishna
    - **Principal Engineer Network Planning** Sujeewa Vithana
    - **Future Networks Engineer** Chirayu Oza
    - **Senior Engineer Network Planning** Nadia Yousif
    - **LV Planning Analyst** Magenga (Stephen) Kayembe
    - **Principal Engineer Network Planning** Roshanth Sivanathan
    - **Senior Power Quality Engineer** Hedy Dalvand
      - **Engineer Power Quality** Adeel Mahmood
    - **Graduate Engineer** Johnny Shan

Head Count: 19.5

Electricity Network

- **General Manager Networks (Electricity)** – Mark Clarke
  - **Personal Assistant** – Simone Azzopardi
  - **General Manager Asset Management** – Craig Savage
    - **Asset Management Officer** – Connie Burnell
    - **Primary Assets Manager** – Michael Ciavarella
      - **Senior Engineer Primary Assets** – Chris Beckett
      - **Principal Engineer Distribution** – Jim Tsirikis
      - **Asset Engineer** – Ryan Woolf
      - **Senior Engineer Asset - Distribution** – Peter Livingston
      - **Senior Asset Engineer - Substations** – Harvinder Luthra
      - **Design Review Manager** – Zhong Fu
      - **Senior Asset Engineer** – Peter Yeung
      - **Team Lead - Substations** – Michael Meraklis
      - **Graduate Engineer** – Lynn Wang
      - **Team Lead - Substations** – Raman Jegatheesan
    - **Secondary Assets Manager** – Robert Simpkin
      - **Communications Engineer** – Sam Ighanian
      - **Senior Protection Engineer** – David Wilkinson
      - **Complex Customer Connections Engineer** – Steve Oh
      - **Senior Protection and Control Engineer** – Goran Ivanovic
      - **Senior Secondary Systems Engineer** – Stephen Major
      - **Protection and Control Engineer** – Soney Soman
      - **Strategic SCADA & Communications Engineer** – Abilash Chandrashekar
    - **Network Performance Manager** – Shaun Glasson
      - **Network Performance Engineer** – Ben Hutchinson
      - **Network Performance Engineer** – Sophia Wang
      - **Network Performance Analyst** – Jane Coogan
    - **Asset Information & Control Systems Manager** – Tobie De Villiers
      - **DMS SCADA Advisor** – Lindsey Hatfield
      - **Real Time Systems Analyst** – Michael Woodrow
      - **AMI Strategy Engineer** – Graeme Watson
      - **Real Time Systems Security Analyst** – Anthony Brooking
      - **SAP Business Advisor** – Albere Cohen
    - **Strategic Works Program Analyst** – Wilson Foo

Head Count: 32

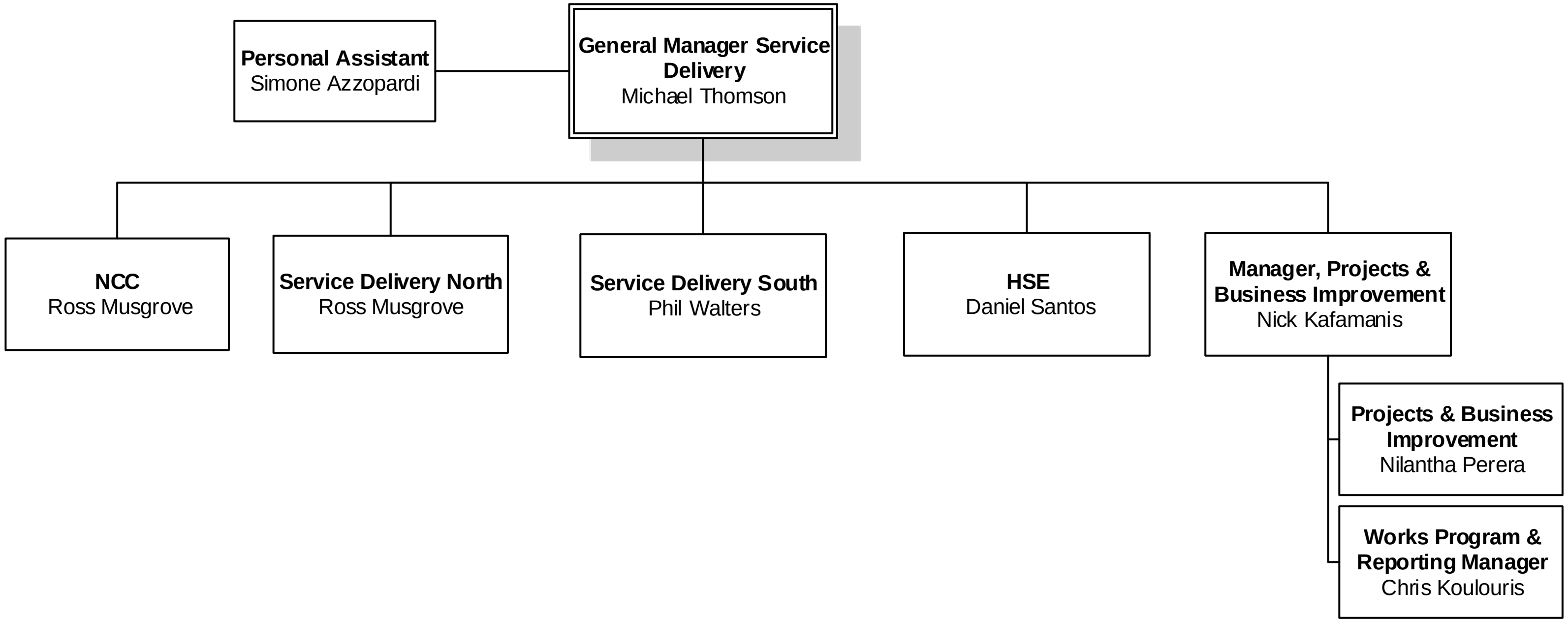
UNITED ENERGY

Multinet GAS

- **General Manager Gas Network** – Mark Beech
  - **PA/Administration Assistant** – Sheryl Gillespie
  - **Technical Compliance Engineer** – Arthur McAuley
  - **Graduate Engineer** – Daryl Lee
  - **Graduate Engineer** – Anja Tomic
  - **Gas Asset Manager**
    - **Senior Engineer Network Planning** – Elsie Zhao
    - **Senior Engineer Network Planning** – John Koutsoukos
    - **Asset Performance & Integrity Manager** – Neil Pendergast
      - **Asset Engineer - Asset Policy, Materials & Technology** – Prateek Kateelkar
      - **Senior Technical Officer** – Max York
      - **Technical Officer - Gas** – Michael Newman
      - **Senior Technical Officer** – Neville Meates
  - **Senior Asset Performance Analyst** – Michael May
  - **Works Program Analyst - Gas** – Julian Bialecki
  - **Graduate Engineer** – Jason Edwards

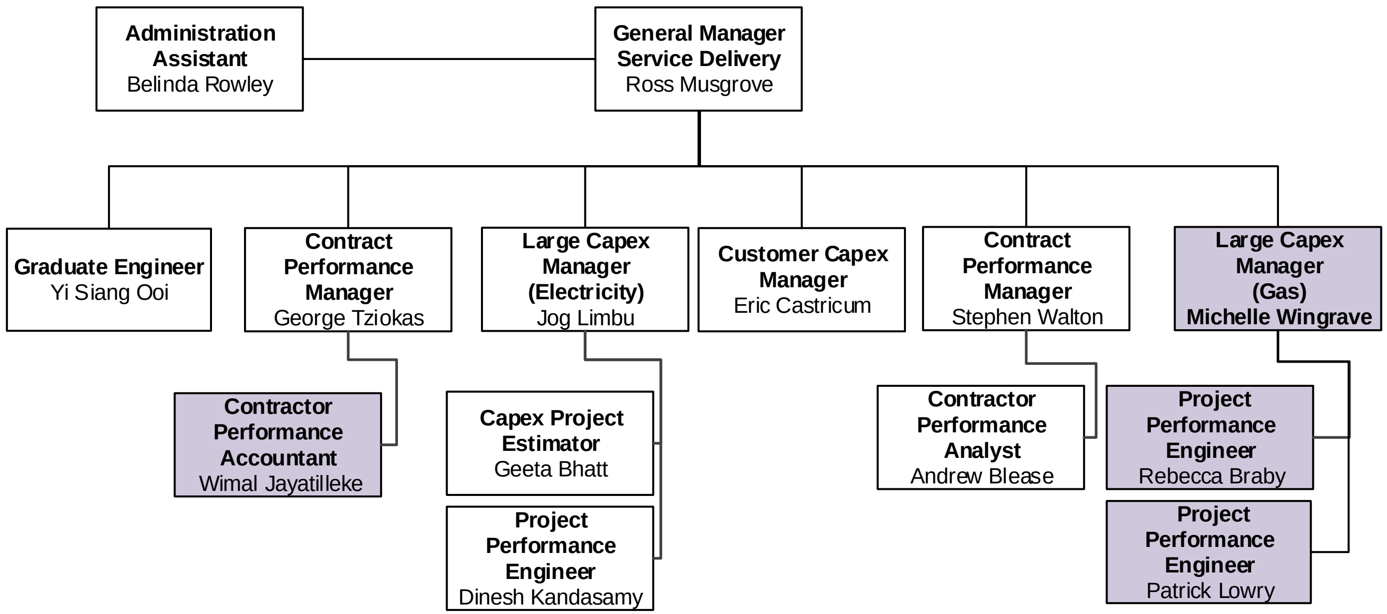
Head Count: 15

Service Delivery



Head Count: 4.5

Service Delivery – North Region



Head Count: 14

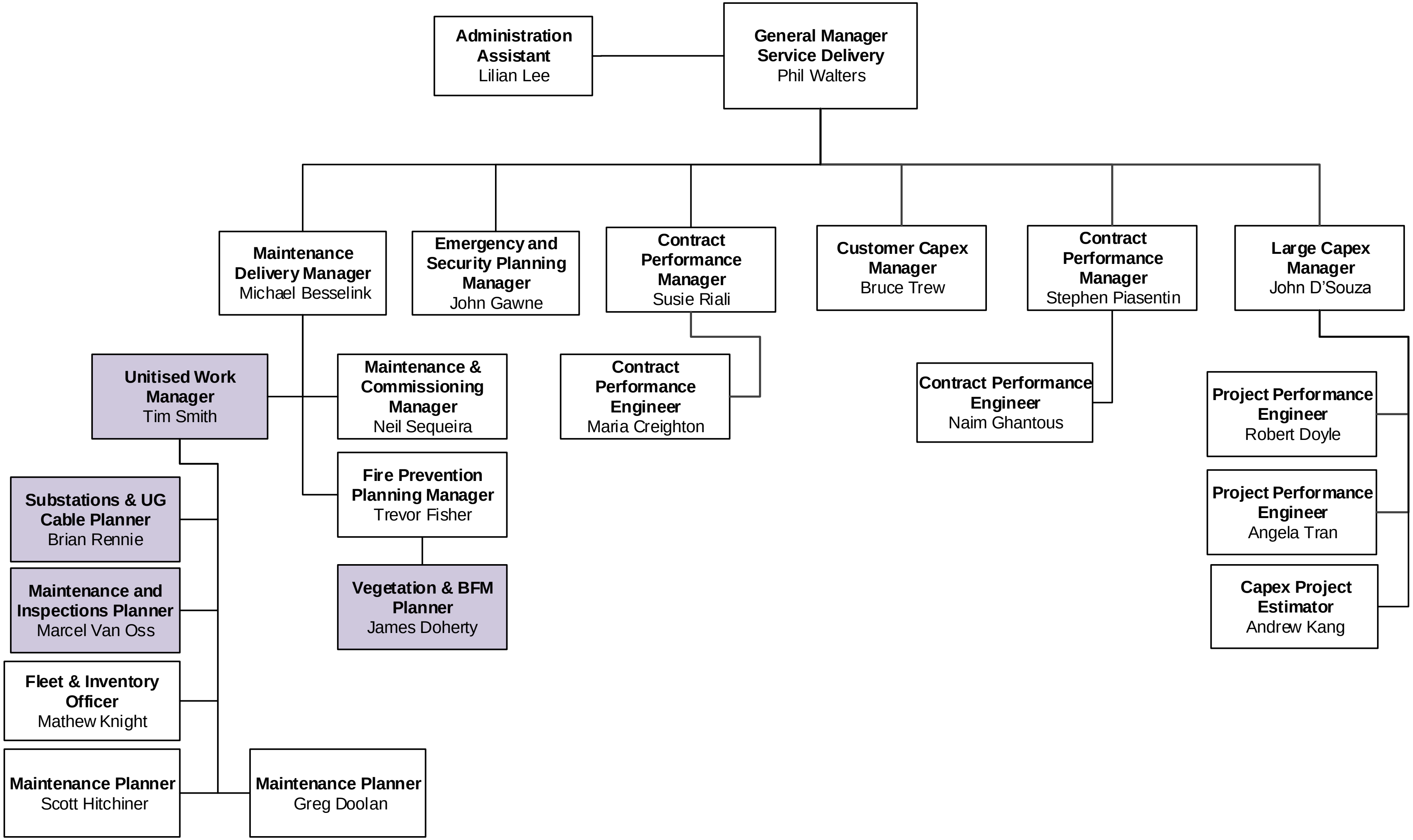
Shared Service across Service Delivery

Network Control Centre

- **General Manager Service Delivery** – Ross Musgrove
  - **NCC Operations Manager** – David Kowal
    - **Network Coordinator** – Rohan Neil
    - **Network Coordinator** – Peter Gillis
    - **Network Coordinator** – Anthony Lind
    - **Network Coordinator** – Robert Milne
    - **Network Coordinator** – Martin Mulcahy
    - **Network Coordinator** – Stuart Sully
    - **Network Coordinator** – Richard Chaplin
    - **Network Coordinator** – Glenn Davis
    - **Network Coordinator** – Bryan Drake
    - **Network Coordinator** – Michael Gleeson
    - **Network Coordinator** – Gil Hartrick
    - **Network Coordinator** – Shane Walsh
    - **Network Coordinator** – Gary Weston
    - **HV Planner** – John Hague
    - **Network Coordinator** – Matthew Colvin
    - **Control Centre Performance Analyst** – Constantin Balanica
    - **Resource Coordinator** – Karen Karam
    - **Resource Coordinator** – Doug Wancia
    - **Resource Coordinator** – Colin Nicholls
    - **Resource Coordinator** – Andrew Vos
    - **Resource Coordinator** – Neil Schrieber
    - **Resource Coordinator** – Sandra Colomb
    - **Resource Coordinator** – Joanne Molnar
    - **Resource Coordinator** – Marika Gannas
    - **Resource Coordinator** – Deanne Bakker
    - **Resource Coordinator** – Ellie Murray
    - **Resource Coordinator** – Tom Hunt
  - **NCC Support Manager** – Andrew Steer
    - **AMI Network Operations Manager** – Alan Robles Perez
      - **AMI Comms Field Technician** – Alok Bhatt
      - **AMI Configuration SME** – Jeanette Olin
      - **AMI Communications Field Technician** – Timothy Sullivan
      - **AMI Testing SME** – Andrew Hurst
      - **AMI Comms Field Technician** – Mark Whiteside
      - **AMI NMS Analyst** – Eugene Echkenko
      - **AMI Configuration SME** – Rogelio Miranda
      - **AMI NMS Analyst** – Wilton Gao
      - **AMI Communications Analyst** – Xaomiao (Amy) Fan
    - **SCADA & DMS Data Administrator** – Robbie Cleland
    - **SCADA & DMS Data Administrator** – Graham Forbes
    - **SCADA & DMS Data Administrator** – Damir Jovanovic
    - **SCADA & DMS Administrator** – Milena Ercegovic
    - **SCADA & DMS Data Specialist** – Xuemei Dai
    - **SCADA & DMS Data Specialist** – Emily Chen
    - **SCADA & DMS Data Specialist** – Anthony Rooney
    - **SCADA Technical Works Manager** – Justin Moon

Head Count: 47

Service Delivery – South Region



Shared Service across Service Delivery

Head Count: 22

Health, Safety & Environment

- **Health, Safety & Environment Manager** – Daniel Santos
  - **Environment Principle Advisor** – Marisa Feher
    - **Environment Officer** – Paul Gibbs
  - **Work Practices Manager** – Adam Beel
    - **Technical Training & Accreditation Officer** – Robert Foord
    - **Network Compliance Officer** – Alex McRobert
    - **Customer Policy Officer** – Wayne Kelly
    - **Gas Works Practices Officer** – Roy Spiers
    - **Gas Works Practices Officer** – Peter Sayce
  - **Health & Safety Manager** – Peter Napolitano
    - **Health, Safety & Environment Coordinator** – Tahntip Powtawe
    - **Health & Safety Officer** – Ashlea Gawne

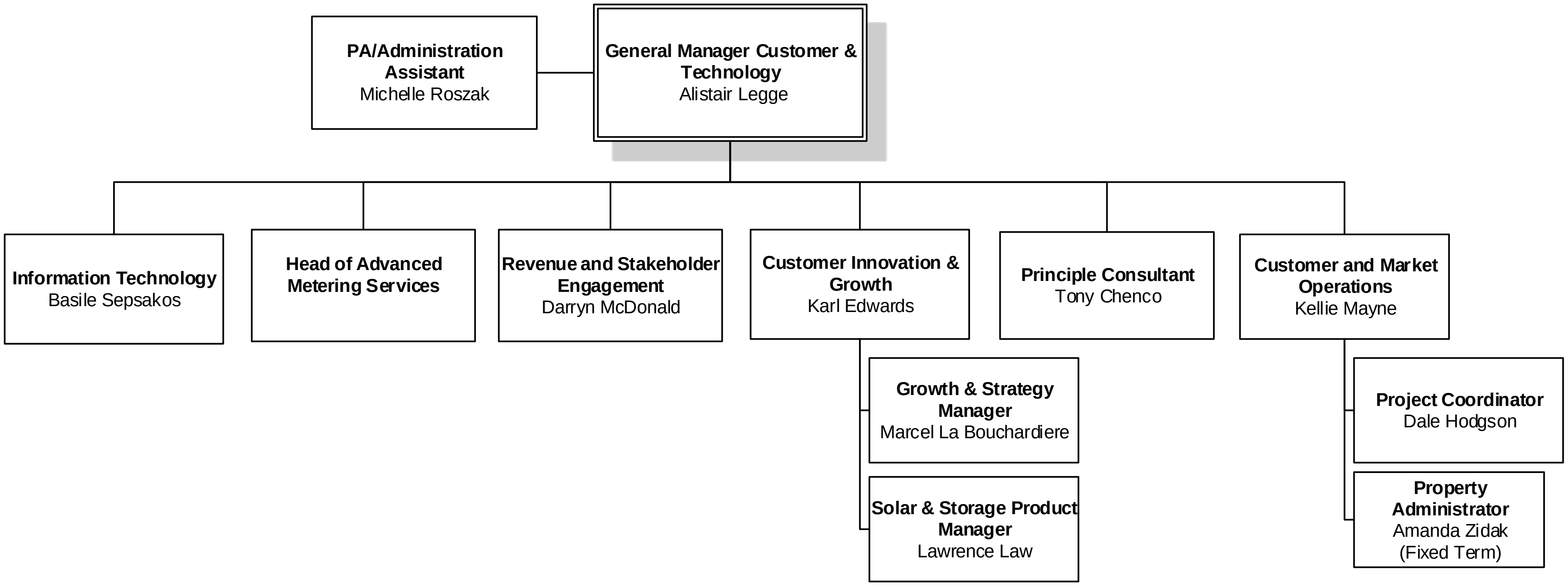
Head Count: 12

Finance

- **Chief Financial Officer** – Anne Hayes
  - **PA/Administration Assistant** – Tania Wickramasurya
  - **Tax Manager** – Peter Ajani
  - **Head of Financial Accounting & Controls** – Michael Vella
    - **Fixed Asset Accountant** – Sue Edwards
    - **Accounts Payable Officer** – Irene Leong
      - **Accounts Payable Officer** – Hera Zhang
    - **Treasury Manager** – Chantal Jodun
      - **Treasury Accountant/ Settlement** – Daisy Ku
    - **Credit Manager** – Christie Addison
      - **Recoverable Works Officer** – Emanuel Hatgidanou
      - **Revenue Support Officer** – Noel Peters
      - **Credit Controller** – Alison McPhail
    - **Financial Accounting Manager** – Roman Babitsky
      - **Corporate Accountant** – Ashley Wang
      - **Corporate Accountant** – William Tan
      - **Assistant Corporate Accountant** – Rebecca Chan
  - **General Manager Corporate Finance** – Andrew Sutcliffe
    - **Senior Manager Corporate Finance** – Andrew Vandeligt
    - **Senior Manager Financial Analysis** – Jarrod Holmes
      - **Financial Analyst** – Dennis Chong
      - **Financial Analyst** – Eric Ma
    - **Process Review Analyst** – Gary Cossens
  - **Head of Management Accounting** – Kimberley Lamden
    - **Management Accountant IT/ Systems** – Agnes Byrne
    - **Management Accountant - CMS** – John Newlands
    - **Senior Management Accountant** – Louie Au
    - **Management Accountant – Multinet Operations** – Vasuki Rajeev
    - **Management Accountant - Operations** – Chinthaka Amaratunga
    - **Management Accountant - AMI** – Shalini Madan
    - **Management Accountant** – Jesse Bernardo
  - **Manager Finance Projects & Systems** – Michael Matthews
    - **Systems Accountant** – Steve Brennan

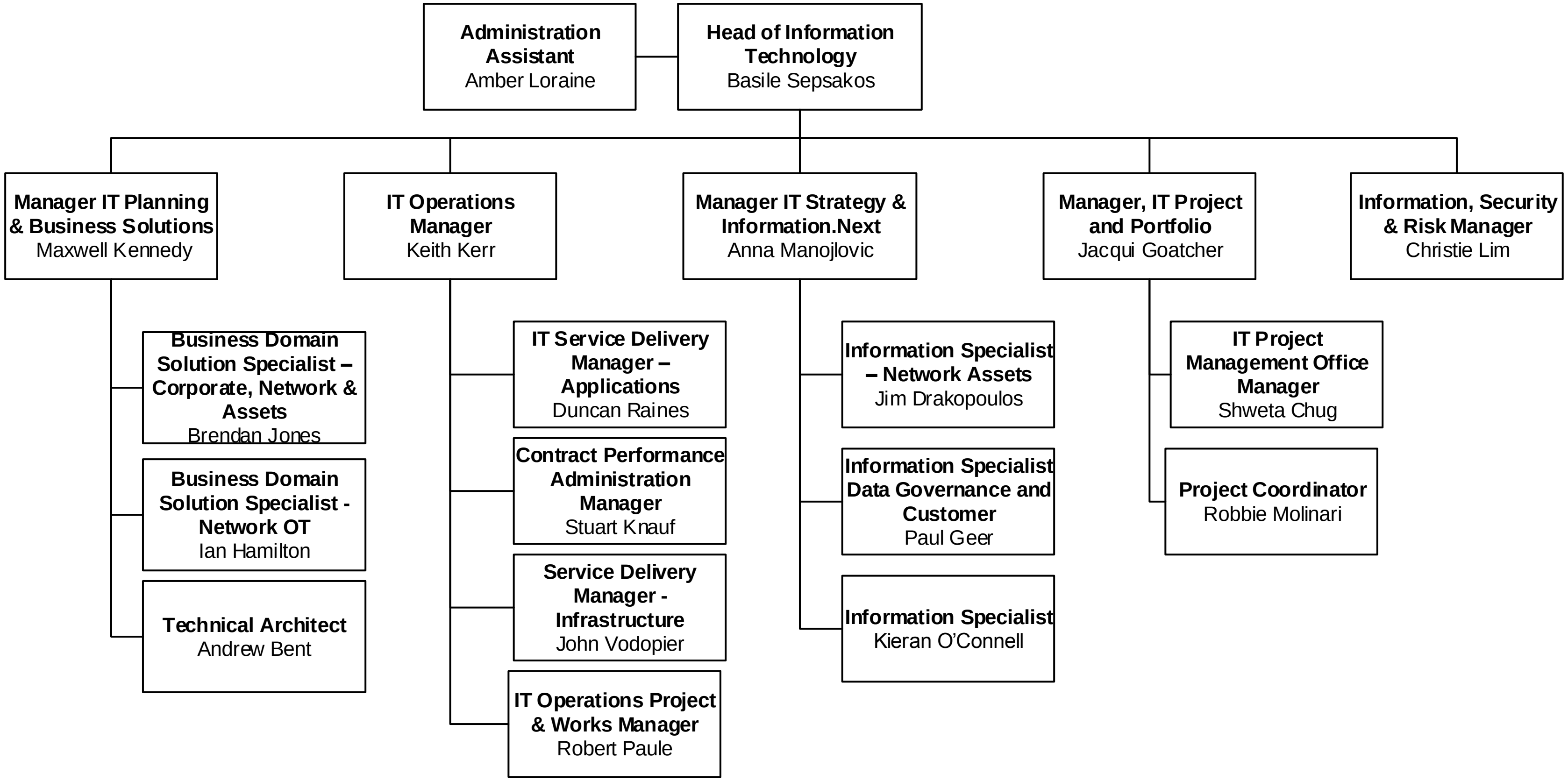
Head Count: 33

Customer & Technology



Head Count: 8

Information Technology



Head Count: 19

Revenue and Stakeholder Engagement

- **Head of Revenue & Stakeholder Engagement** – Darryn McDonald
  - **Revenue Manager** – Stephen Harrison
    - **Revenue Analyst** – John Pomeroy
    - **Revenue Analyst** – Simone Burger
    - **Senior Pricing and Forecasting Analyst** – Laszlo Milias
  - **Manager Customer Experience** – Debbie Jackson
    - **Community & Stakeholder Relations Manager** – James Wong
      - **Commercial Account Manager** – Ian Norris
      - **Retailer Account Manager** – Nichole Chaplin
    - **Business Partnership Manager**
      - **Facilities Access – NBN Rollout** – Tony Johnson
    - **Customer Insights Analyst** – Scott Morrow
  - **Product Manager Energy Network Services** – Inna Kulawiec

Head Count: 33

UNITED ENERGY

Multinet GAS

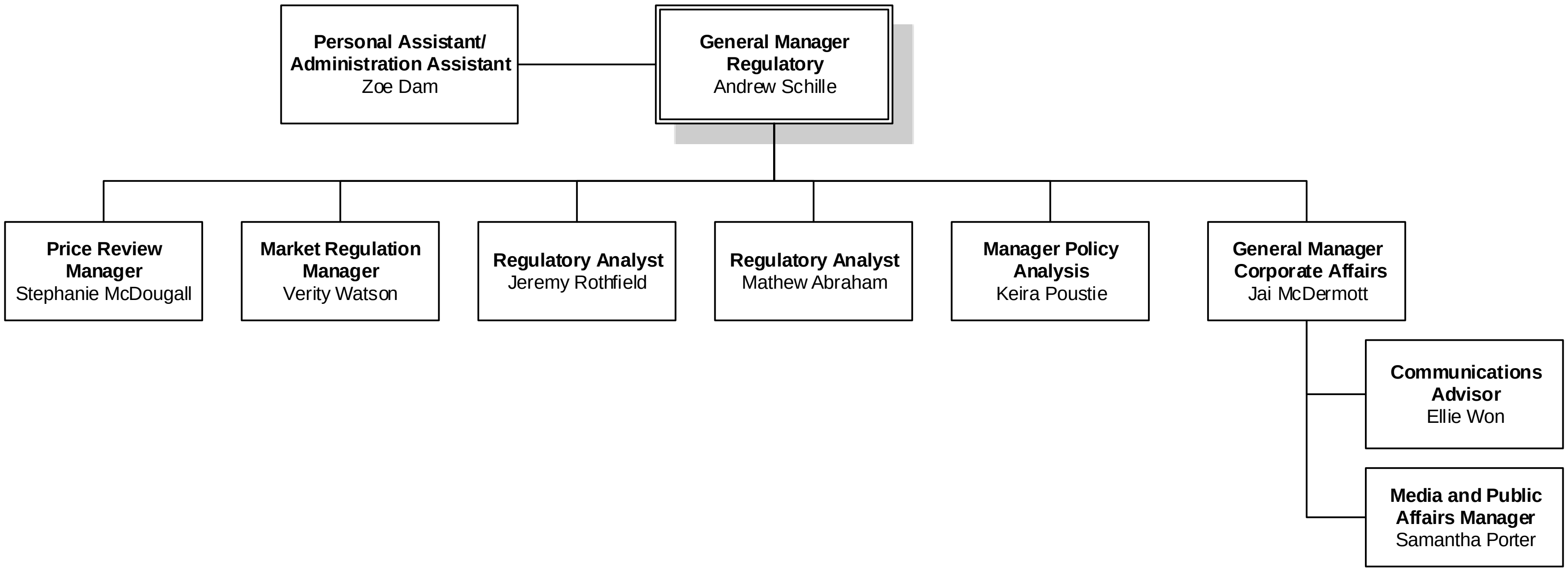
- **Head of Customer & Market Operations**
  Kellie Mayne
  - **Manager Market Services**
    - **Market Compliance Manager**
      Deborah Senior
    - **Market Interface Manager**
      - **Gas Subject Matter Expert**
        Kelly Murray
      - **Back Office SME**
        Anthony Rundle
      - **Back Office SME**
        Dianne Signorelli
      - **Back Office SME**
        Pubudu Jayawardene
      - **Back Office SME**
        Jacqui De Lisle
      - **Back Office SME**
        Can Turk
  - **Manager Metering**
    Wayne Gorman
    - **Electricity Metering Engineer**
      Goutham Lingam
    - **Senior Metering Engineer**
      Neville Hutchinson
      - **Gas Metering Engineer**
        Anna D'Souza
    - **Metering Field Operations Manager**
      Mick De Lisle
      - **Metering Projects Manager**
        Fabian Perez
      - **Metering Projects Manager**
        John Ward
  - **Manager Customer Operations**
    Kristina Thompson
    - **Customer Service SME**
      Daniela Peirano
    - **Customer Portal Manager**
      David Hutchinson
    - **Customer Service Knowledge Management Coordinator**
      Guy Dunkley
    - **Customer Resolutions Agent**
      Brett Robinson
    - **SWAT Team Leader**
      Paul Mulholland
      - **AMI Audit & Compliance Coordinator**
        Richard Baillie
    - **AMI Customer Service Team Leader**
      Jessica Mortimer
    - **Customer Resolutions Agent**
      Geoffrey Coppin
    - **Reporting Analyst**
      Cassandra Arnold
    - **Customer Resolutions Agent**
      Stacy Shepherd
    - **Administration Support Officer**
      Alana La Bouchardiere
    - **Customer Resolution Centre Manager**
      Susanna Douglas
      - **Customer Resolution Agent**
        Amanda Rehana
      - **Customer Resolution Coordinator**
        Karen Pepper
      - **Customer Resolutions Agent - Tier 2**
        Brent Davidson
      - **Customer Resolutions Agent - Tier 3**
        Laura Mejia

Head Count: 32

- **General Counsel** Rob Sarafian
  - **Senior Legal Counsel/ Commercial Manager** Tanya Esposito
    - **Commercial Advisor/ Legal Advisor** Audrey Waldegrave
    - **Senior Legal Counsel** Joe Game
  - **Assistant Company Secretary** Shanika Amarasinghe
    - **Corporate Services Officer** Rosie Lavin
  - **Head of Procurement** Curtis Mackenzie
    - **Commercial Manager/ Legal Advisor** Stephen Lou
    - **Commercial Manager/ Legal Advisor** Nicholas Hall
    - **Commercial Manager** Michael Dancey

Head Count: 11

Regulatory & Corporate Affairs



Head Count: 10

Appendix L – Confidentiality template

This appendix addresses Section 13.1 of the Annual RIN.

Table 1: Confidentiality template

Title, page and paragraph number of document containing the confidential information	Description of the confidential information.	Topic the confidential information relates to (e.g. capex, opex, the rate of return etc.)	Identify the recognised confidentiality category that the confidential information falls within.	Provide a brief explanation of why the confidential information falls into the selected category. If information falls within 'other' please provide further details on why the information should be treated as confidential.	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information.	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit (especially public benefits such as the effect on the long term interests of consumers).
Annual Financial RIN Excel Template	Related party margins	Capex and opex	Market sensitive cost inputs	Related party margins data is market sensitive information.	Disclosing related party margins would affect United Energy's ability to obtain competitive prices in future transactions.	The information is not required to understand United Energy's total costs.

Table 2: Proportion of confidential information

Submission Title	Number of pages of submission that include information subject to a claim of confidentiality	Number of pages of submission that do not include information subject to a claim of confidentiality	Total number of pages of submission	Percentage of pages of submission that include information subject to a claim of confidentiality	Percentage of pages of submission that do not include information subject to a claim of confidentiality
Annual Financial RIN Excel Template	3 tabs	25 tabs	28 tabs	10.7%	89.3%

Appendix M: Board Minutes

Note: See attached

United Energy Distribution Pty Limited (ACN 064 651 029)
Extract of minutes of the Meeting of Directors

I certify that:

- The following is a resolution passed at the Board meeting held on 28 April 2015; and
- The resolution will be recorded in the Company's minute book as required by section 251A of the Corporations Act 2001 (Cwlth) ("Corporations Act").

....29/4/15..........
Signature of Company Secretary Date

Robert Sarafian
....
Name of Company Secretary

5. Approval of RIN for year ended 31 December 2014:	15/38	IT WAS RESOLVED THAT the Board: approve the Regulatory Information Notice (RIN) for submission to the Australian Energy Regulator, noting that to the best of the Board's information, knowledge and belief: - the information provided in the response to paragraph 1.1(a) of the RIN (being the information to be provided in the workbook) is true and fair; and - the service target performance incentive scheme and demand information provided in the response to paragraph 1.1(b) (being the information to be provided in templates 1(a) – (e), 2 and 3 of the workbook) is true and fair.