Annual Regulatory Information Notice 2016

Contact: Mathew Abraham
Regulation
United Energy
Phone: 03 8846 9758

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Annual Regulatory Information Notice 2016

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Appendices

1. Introduction

United Energy is required to respond to the Annual Regulatory Information Notice (RIN), issued on 3rd February 2016 under Division 4 of Part 3 of the *National Electricity Law* (NEL).

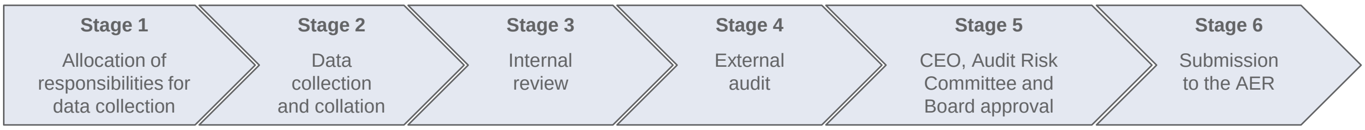
The Notice requires United Energy to provide, prepare and maintain the information in the manner and form specified in the Notice issued on 3rd February 2016. The AER requires the information for the performance or exercise of a function or power conferred on it under the NEL or the *National Electricity Rules* (NER).

The Excel templates in which the information is provided, were issued as final by the AER on the 3rd February 2016.

The information contained in the templates relates to the 2016 calendar year only.

1.1 Preparation process

The following diagram provides a high-level summary of UE's approach to preparing the 2016 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 information required in the Financial Information Templates in the Microsoft Excel workbook attached at Appendix B;** **b) the information required in the Non-Financial Information Templates in the Microsoft Excel workbook attached at Appendix B;**	Appendix A – Annual RIN Excel Template (b) does not apply
c) a Microsoft Excel workbook or other information that reconciles and explains Adjustments between the Audited Statutory Accounts and the Financial Information Templates. United Energy must separately list each Adjustment made to derive the Financial Information Templates. For each Adjustment made: **i. specify the amount of 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 which must, for all information provided in Appendix B: **i. demonstrate how the information provided is consistent with the requirements of this Notice;** **ii. explain the source from which United Energy obtained the information;** **iii. explain the methodology United Energy applied to provide the required information, including any assumptions United Energy made;** **iv. explain, in circumstances where United Energy cannot provide Actual Information:** **1) why it was not possible for United Energy to provide Actual Information;** **2) what steps United Energy is taking to ensure it can provide the information in the future;**	Appendix C – Basis of preparation

Clause detail	United Energy response
3) if an estimate has been provided, the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is United Energy best estimate, given the information sought in this Notice.	
e) the Regulatory Accounting Principles and Policies for the Relevant Regulatory Year.	Appendix F2 – Cost Allocation Methodology (CAM) and Appendix F3 Capitalisation Policy
f) the Capitalisation Policy for the Relevant Regulatory Year.	Appendix F3 Capitalisation Policy
g) 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
1.2 Identify all material changes between the Regulatory Accounting Principles and Policies provided in the response to paragraphs 1.1(e) for the relevant regulatory year and the previous regulatory year. 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 material changes between the statements of the policy for determining the allocation of overheads in accordance with the approved Cost Allocation Method, for the Relevant Regulatory Year and the previous regulatory year. For each change identified: **a) explain the nature of and the reasons for the change; and** **b) quantify the effect of the change on information in the Financial Information Templates for the Relevant Regulatory Year**	Not applicable – no differences
1.4 If United Energy has previously provided the AER with the policies sought in paragraphs 1.1(e), (f) or (g) it is not necessary for United Energy to provide each policy again unless it identified a material change in response to paragraphs 1.2, 1.3 or 5.1.	

Clause detail	United Energy response
1.5 Identify each difference (where the difference is equal to or greater than ±10 per cent) between the amount reported in the Financial Information Templates and the amount provided for in the 2016-20 Distribution Determination for the following: **a) total actual operating expenditure and total forecast operating expenditure; and** **b) total actual capital expenditure and total forecast capital expenditure.**	Appendix G – Explanation of material differences
1.6 Explain the reasons for each difference identified in the response to paragraph 1.5.	Appendix G – Explanation of material differences
1.7 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
1.8 Explain the reasons for each difference identified in the response to paragraph 1.7	Appendix G – Explanation of material differences
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 2016-20 Distribution Determination.	UE has classified distribution services in accordance with the CAM and Capitalisation Policy approved by the AER in line with the 2016-20 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 2016-20 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 2016-20 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.

Clause detail	United Energy response
	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.
2.4 Describe the process *United Energy* has in place to monitor compliance with the Essential Services Commission of Victoria, *Electricity Industry Guideline No. 17: Electricity Ring-fencing Issue 1,* October 2004 (or any Ringfencing Guideline the *AER* may develop under clause 6.17.2 of the *NER)*. List all instances of non-compliance, including the date of non-compliance event, reason for non-compliance, impact on customers, impact on competitors, and any remedial action taken by *United Energy*.	Not applicable – UE does not have a Ring-fenced entity
3. Cost allocation to distribution business	
3.1 Identify each expenditure or revenue item in Worksheet 8.1 of the Financial Information Templates that is directly attributable to the Distribution Business	
3.2 Identify each Item in the Regulatory Accounting Statements that is: **a) not directly attributable but is allocated on a causation basis to the Distribution Business; and** **b) not directly attributable and cannot be allocated on a causation basis to the Distribution Business.**	All costs have been directly allocated. Refer to Appendix F – Cost allocation to regulated distribution business and cost allocation to service segments.
3.3 For each Item identified in the response to paragraphs 3.2(a): **c) state the amount of the item that has been allocated;** **d) explain the method of allocation and reasons for choosing that method; and** **e) state the numeric amount of the allocator(s) used.**	All costs have been directly allocated. Refer to Appendix F – Cost allocation to regulated distribution business and cost allocation to service segments.
3.4 For each Item identified in the response to paragraphs 3.2(b): **a) state the amount of the Item and whether it was material;** **b) explain the method of allocation and reasons for choosing that method; and** **c) explain the reason(s) why it cannot be allocated on a causation basis**	All costs have been directly allocated. Refer to Appendix F – Cost allocation to regulated distribution business and cost allocation to service segments.

Clause detail	United Energy response
4. Cost allocation to service segments ***Note: Service segment refers to standard control services, alternative control services, negotiated services.***	
4.1 Identify each item in the Regulatory Accounting Statements that is: **a) directly attributable from the Distribution Business to a service segment;** **b) not directly attributable but is allocated on a causation basis from the Distribution Business to a service segment; and** **c) not directly attributable 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 F – Cost allocation to regulated distribution business and cost allocation to service segments.
4.2 For each Item identified in the response to paragraphs 4.1(a): **a) state the amount of the Item that has been directly attributable to a service segment.**	All costs have been directly allocated. Refer to Appendix F – Cost allocation to regulated distribution business and cost allocation to service segments.
4.3 For each Item identified in the response to paragraph 4.1(b): **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 F – Cost allocation to regulated distribution business and cost allocation to service segments.
4.4 For each Item identified in the response to paragraphs 4.1(c): **a) state the amount of the Item and whether it was material;** **b) explain the method of allocation and reasons for choosing that method; and** **c) explain the reason(s) why it cannot be allocated on a causation basis.**	All costs have been directly allocated. Refer to Appendix F – Cost allocation to regulated distribution business and cost allocation to service segments.

Clause detail	United Energy response
5. Capitalisation policy	
5.1 Identify all material changes between the Capitalisation Policy for the Relevant Regulatory Year and the previous regulatory year. **5.2 For each change identified in the response to paragraph 5.1:** **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 2016-20 Distribution Determination during the Relevant Regulatory year.** **d) explain the effect of the change, if any, on the actual operating and actual capital expenditure incurred, in comparison to the previous Relevant Regulatory Year.**	Not applicable – No changes to the capitalisation policy
6. Demand Management Incentive Allowance	
6.1 Identify each demand management project or program for which United Energy seeks approval.	Appendix H – Demand Management Incentive Scheme Report – 2016

Clause detail	United Energy response
6.2 For each demand management project or program identified in the response to paragraph 6.1: **a) explain:** **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**	Appendix H – Demand Management Incentive Scheme Report – 2016
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 2016-20 Distribution Determination or recoverable under any other incentive scheme in that determination; and**	Appendix H – Demand Management Incentive Scheme Report – 2016
c) state the total amount of the Demand Management Innovation Allowance spent in the Relevant Regulatory Year and how this amount has been calculated.	Appendix H – Demand Management Incentive Scheme Report – 2016

Clause detail	United Energy response
6.3 Provide 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.	Appendix H – Demand Management Incentive Scheme Report – 2015
7. Tax Standard Lives	
7.1 Identify all tax standard asset lives applied to asset classes that differ from those contained in the AER approved PTRM for United Energy's current regulatory control period.	Not applicable – there is no asset classes that differ from those contained in the AER approved PTRM for United Energy's current regulatory control period
7.2 Explain the reasons for each difference identified in paragraph 7.1 including reasons for any departure from the ATO's most recent determination of effective life.	Not applicable – there is no asset classes that differ from those contained in the AER approved PTRM for United Energy's current regulatory control period
8. Charts	
8.1 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
9. Audit & Review Reports	
9.1 Provide Audit Report and Review report(s) in the form of: **a) an Audit Report (financial information) in accordance with the requirements set out at Appendix D** **b) A Review Report (for Non-Financial Information) in accordance with the requirements set out at Appendix D.**	Appendix J – Audit reports
10. Confidential information	

Clause detail	United Energy response
10.1 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 to 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.**	Appendix L – Confidentiality template
10.2 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 10.1.	Refer to Annual RIN submission transmittal email

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.

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
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 C: Basis of preparation – Annual RIN 2016

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 2016 - Annual RIN - Financial Information'* and *'United Energy 2016 - 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 2016

The following tables outline the basis of preparation of the information provided in the Microsoft Excel Workbook titled ‘*United Energy 2016 - Annual RIN –Financial Information’.*

Table 3: Annual Financial RIN details

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
2.11 Labour	Labour/Non-labour Expenditure Split	3.1	Opex	🟩	F	SAP	In-house labour expenditure is SCS portion of total employee expenses from UE Statutory accounts Consolidated income statement. Labour expenditure outsourced to related parties: data from SAP, capturing the Standard Control portion of the total ZNX labour cost under GL71000 cost centre UE1420. Labour expenditure outsourced to unrelated parties: data from SAP, capturing the Standard Control portion of Downer labour cost under GL71000 cost centre UE1430. Controllable non-labour expenditure: all other SCS opex falls under this category. The same Standard Control percentage applies to each line listed above. It is the percentage of total Standard Control opex per Annual RIN Tab 8.4 Opex Cell G71 over total Distribution business Opex per Annual RIN Tab 8.4 Opex Cell E71.	
		3.2	Capex	🟩	F	SAP	In-house labour expenditure is the SCS portion of total costs for cost centres UE1996, UE1997, UE1998 and UE1999	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩			Labour expenditure outsourced to related parties: data from SAP, capturing the Standard Control portion of the total ZNX capex labour uploaded through Gateway. Labour expenditure outsourced to unrelated parties: data from SAP, capturing the Standard Control portion of the total Downer capex labour uploaded through Gateway. Controllable non-labour expenditure: all other Standard Control Capex falls under this category. The same Standard Control percentage applies to each of line listed above. It is the percentage of total Standard Control Capex per Annual RIN Tab 8.2 Capex Cell D37 over total Distribution business Capex per Annual RIN Tab 8.2 Capex Cell D96.	
3.6 Quality of Services	Quality	3.6.6	Complaints - Technical Quality of Supply	🟩	NF	UE SAP CRM	Data from the system generated report	
		3.6.7.1	Timely provisions of services	🟩		Service provider report	Service Provider Connections Monthly Reporting	
		3.6.7.2	Timely repair of faulty street lights	🟩		Service provider report	OUA Reports	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
		3.6.7.3	Call centre performance	🟩		Service provider report	Service Provider Connections Monthly Report Service Provider Daily Report (raw) - Faults Desk only Service Provider Monthly Report (Faults tab)	
		3.6.7.4	Number of customer complaints	🟩		UE SAP CRM	Data from the system generated report	
3.6.8 Network Feeders	Network Feeder Reliability	3.6.8	Feeder Id, Description of Feeder, Feeder classification	🟩	NF	Metering Data Geographical Information System (GIS) OUA	A list of feeder IDS are compiled from various systems from UE (Load forecast spreadsheet maintained by Network Planning which lists demand for each feeder, Customer Numbers by feeder from OUA and Feeder lengths from GIS). This list is filtered to only include feeders which had at least one of the following - non zero customer numbers, non zero length, non zero demand. This list was then checked to filter out non UE feeders, very short feeders with no customers (e.g. Station service transformers) and feeders that have been renamed (all data is listed under the new name) or designated as a future feeder. The feeder classification is based off an initial assessment which is made based on length and demand (as per AER definitions). Where demand/length data is not available due to the feeder being serviced by another	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩			provider, the classification is based off the previous year's RIN by that provider. Any new feeders or feeders that have changed classification from the previous RIN are checked to see whether the feeder should be classified differently (due to being in an urban area for example)	
			Reliability Length of overhead and underground lines	🟩	NF	Geographical Information System AM/FM Reports	Asset data in the AM/FM reports is updated monthly from UE’s GIS and presented in user friendly tables.	
			Maximum demand	🟩	NF	Metering Data	The Maximum Demand is obtained from the Network Planning Team who use actual metered data.	
			Data Energy not supplied, planned & unplanned	🟩	NF	OUA DMS Metering Data	Energy not supplied is calculated as the average demand x SAIDI / 60 minutes The average customer demand was calculated for each Medium Voltage (MV) feeder using the hourly data extracted from the PI Historian software. PI historian records the following values: • Average MW / hr • Average MVAr / hr The hourly readings were aggregated to a year for each MV feeder. Therefore,	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
3.6.9 Network Reliability				🟩			Average Demand per Feeder (MVA) = SQRT[(MW_AVG)^2 + (MVAr_AVG)^2] See below for SAIDI	
			Outage information and Statistics	🟩	NF	OUA DMS	Raw unplanned data is downloaded from the DMS Database. The data is "cleansed" to remove duplications, system errors (events that should have been cancelled), ensure each event has a valid feeder name, split out outages affecting multiple feeders into each feeder component and check SAIFI/MAIFI overrides. Raw planned data is downloaded from OUA. The data is checked to ensure each entry has a valid feeder ID and that the time appears correct (events over 1 day are usually a system error and have not been closed out correctly) SAIDI is calculated as CMOS/customers on feeder SAIFI is calculated as customers affected/customers on feeder	
				🟩	NF	OUA Annual RIN 2016 Tab 3.6.8	Raw planned data is downloaded from OUA. The data is checked to ensure each entry has a valid feeder ID and that the time appears correct (events over 1 day are usually a system error and have not been closed out correctly). SAIDI and SAIFI are calculated in accordance with AER	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩			definitions. Refer to Annual RIN tab 3.6.8 for feeder classifications.	
4.1 Public Lighting	Public Lighting Metrics by Tariff	4	Public Lighting - Current Year	🟩	F	SAP Financial accounts and GIS Report	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 and is based on categories used in regulatory submissions. Individual breakdown into tariff category has been provided in the GIS monthly report as the number of MRUs per the tariff category and is based on categories used in regulatory submissions. Public lighting revenue data extracted from UE general ledger split into tariff categories based on relevant billing codes and public lighting volume data from SAP billing split into tariff categories.	
6.2 STPIS Reliability	Reliability and customer service performance	1	Unplanned Minutes Off Supply (SAIDI)	🟩	NF	DMS Annual RIN Tab 3.6.8	Raw data is downloaded from the DMS Database. The data is "cleansed" to remove duplications, system errors (events that should have been cancelled), ensure each event has a valid feeder name, split out	UE have no 'long rural' or CBD feeder classification and information is therefore not provided. Calculations are completed in accordance with AER definitions. The feeder

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
		2	Unplanned Interruptions to Supply (SAIFI)	🟩			outages affecting multiple feeders into each feeder component and check SAIFI/MAIFI overrides. SAIDI, SAIFI and MAIFI performance is calculated in accordance with AER definitions. Refer to Annual RIN tab 3.6.8 for feeder classifications. These events are then filtered further for excluded events and MED. Excluded events and MED records are maintained by Network Performance team.	classification is taken from RIN Tab 3.6.8. The average distribution customer numbers used in calculations is taken from RIN Tab 6.2 Table 6.2.4. UE have no 'long rural' or CBD feeder classification and information is therefore not provided. Calculations are completed in accordance with AER definitions. The feeder classification is taken from RIN Tab 3.6.8. The average distribution customer numbers used in calculations is taken from RIN Tab 6.2 Table 6.2.4.
		3	Unplanned Momentary Interruptions to Supply (MAIFI)	🟩				
		4	Distribution Customer Numbers	🟩		Benchmarking RIN 3.4 GIS	The total customer numbers are extracted from Tab 3.4 of the Benchmarking RIN. The customer numbers per feeder is then obtained from GIS and then adjusted on a pro rata basis to match the total in the Benchmarking RIN (due to slight differences in the system)	
6.6 STPIS Customer Service				🟩	NF	Aegis Daily Report (raw) – Faults Desk	Number of calls received and number of calls answered within 30 seconds is extracted from the Daily Faults 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.	
6.7 STPIS Daily	Daily Performance Data -	6.7.1	Unplanned - Customer Service	🟩	NF	Service Provider	Raw data is downloaded from the DMS Database. The data is "cleansed" to remove duplications, system errors (events that	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
Performance				🟩		Daily Report	should have been cancelled), ensure each event has a valid feeder name, split out outages affecting multiple feeders into each feeder component and check SAIFI/MAIFI overrides.. MAIFI performance is calculated in accordance with AER definitions. Refer to Annual RIN tab 3.6.8 for feeder classifications. These events are then filtered further for excluded events and MED. Excluded events and MED records are maintained by Network Performance team.	
6.8 STPIS Exclusions	No requirement to complete as per the RIN sheet							
6.9 STPIS GSLs	Guaranteed service levels – Jurisdictional GSL scheme	6.9.1	Guaranteed Service Levels - Jurisdictional GSL Scheme (Connections)	🟩	NF	Service Provider Connections Monthly Reporting	The number of connections and those not meeting timeframe are monitored via monthly reporting. This monthly reporting is utilised to populate the RIN	
		6.9.1	Guaranteed Service Levels - Jurisdictional GSL Scheme (Appointments)	🟩		Service Desk Appointments (provided by Skill-tech), Connections Appointments are listed in the	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	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩		Connections Monthly reports.	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.	
		6.9.1	Guaranteed Service Levels - Jurisdictional GSL Scheme (Reliability of supply)	🟩		OUA Reports analysed via reporting database	Outages (as the source of data for Reliability of Supply) are monitored using the UE Faults system DMS. OUA reporting system is utilised to extract this data and upload to a reporting database to analyse extracts and return results to populate the RIN.	
		6.9.1	Guaranteed Service Levels - Jurisdictional GSL Scheme (Street Lights)	🟩		OUA Reports	Street Light Faults are monitored using the UE Faults system DMS. OUA reporting system is utilised to analyse this data and return results to populate the RIN.	
		6.9.1	Guaranteed Service Levels - Jurisdictional GSL Scheme (Planned Interuptions)	🟩		OUA Reports	Planned Outages are monitored using the UE Faults system DMS. OUA reporting system is utilised to analyse this data and return results to populate the RIN.	

<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>Methodology</th><th>Additional Comments</th></tr>
<tr><td>7.8 Avoided TUOS Payments</td><td></td><td>1</td><td>Avoided TUOS Payments</td><td>🟩</td><td>F</td><td>SAP Financial Accounts</td><td>SAP data of all payments made by United Energy for embedded generation to businesses and customers during CY2016.</td><td></td></tr>
<tr><td>7.10 Juris Scheme</td><td></td><td>-</td><td>Jurisdictional Scheme Payments</td><td>🟩</td><td>F</td><td>SAP</td><td>Data extracted from SAP as per AER definitions.</td><td></td></tr>
<tr><td>7.11 DMIS-DMIA</td><td></td><td>1</td><td>DMIA Projects submitted for Approval</td><td>🟩</td><td>F</td><td>SAP</td><td>Data extracted from SAP based on WBS transaction report as per AER definitions.</td><td></td></tr>
<tr><td>7.12 Safety and Bushfire</td><td></td><td>n/a</td><td colspan="6">No requirement to complete</td></tr>
<tr><td>7.13 TARC</td><td></td><td>1</td><td>Total Annual Retailer Charges</td><td>🟩</td><td>F</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>373,292,500.27</td></tr>
<tr><td>Jurisdictional scheme amounts</td><td>17,325,083.00</td></tr>
<tr><td>TUOS revenue</td><td>112,487,662.00</td></tr>
<tr><td><i>Other Revenue</i></td><td></td></tr>
<tr><td>Standard Control Services</td><td>1,074,113.61</td></tr>
<tr><td>Other</td><td></td></tr>
<tr><td>Connection Services</td><td>3,077,869.90</td></tr>
<tr><td>Metering Services</td><td>61,655,903.11</td></tr>
<tr><td>Ancillary Network Service</td><td>3,585,968.38</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Total</td><td>572,499,100.27</td></tr>
</table>
Tariff categories TARC Revenue Distribution, Rebates, Fire Factor, PFIT/TFIT, AMI, TUOS/Grid Fees, Avoided TUoS, Public Lighting (OMR), and other excluded services.</td></tr>
</table>

Appendix C: Basis of preparation – Annual RIN 2016

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩				
8.1 Income		1	Revenue	🟩	F	SAP	Distribution revenue from Statutory accounts. Other revenue data extracted from UE general ledger split into Regulatory categories based on relevant billing codes	
		2	Expenditure	🟩	F	SAP	Consolidation of data from tabs contained within the Annual Financial RIN.	
		3	Profit	🟩	F	SAP	Consolidation of data from tabs contained within the Annual Financial RIN.	
8.2 Capex		1	Standard Control Service	🟩	F	SAP	Extracted a list of statutory capital additions from SAP summarised by SAP capital project and categorised it based on the SAP expenditure type field held on the capital project. Related Party Margin has been determined from a SAP report of the related party margin by capital project, categorised based on the SAP expenditure type field held on the capital project. The voltage has predominately been determined from the material activity code the expenditure resides against. Connections at LV has been adjusted by ACS Connection Services and Unregulated services (damages recoverable works)	New customer connections (underground elective) adjusted for capital allocated to Other Alternative Control

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
		2	Material Difference Explanation	🟩	F	N/A	Analysed the makeup of the forecast and actual capital and compared the two.	
		3	Other Capex	🟩	F	SAP Service provider costs	Extracted a list of statutory capital additions from SAP summarised by SAP capital project and categorised it based on the SAP expenditure type field held on the capital project. For the categories of Connections services and Ancillary network 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.	
		4	Capex by Asset Class	🟩	F	SAP	Extracted a list of statutory capital additions from SAP summarised by SAP capital project and categorised it based on the SAP expenditure type field held on the capital project. For the categories of Connections services and Ancillary network 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.	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 Service provider costs	Data generated as follows: 'Subtransmission' total as per Table 1 less SCADA capital in table 1 classified as Subtransmission; 'HV' and 'LV' totals as per Table 1 plus Table 1 voltage of 'Other'	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩			against Augmentation, Connections and Replacement, less SCADA capital in Table 1 classified as Other; 'SCADA/Network Control' categorised as per the classification method in Table 1; 'Non network - IT' total as per Table 1; 'Non network - other' total as per Table 1; 'Public Lighting' total as per Table 3; 'Alternative Control - Other' total as per Table 3; 'Unregulated services' total represents damages recoverable works, determined by work charged to the customer recorded against the relevant billing code in SAP	
		5	Capital Contributions by Asset Class	🟩	F	SAP	Data extracted from the United Energy general ledger against relevant Billing codes 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	Extracted a list of statutory retirements with proceeds and categorised it based on the SAP asset class field. SCADA disposals relate to funds received from a legal dispute which occurred in CY2016. None	Proceeds from the sale of assets has been reported
8.4 Opex		1	Operating Expenditure	🟩	F	SAP Audited statutory accounts	**Maintenance expenditure:** SAP download of every WBS element by MAT code which determines the line classifications and regulatory categories. Data generated from SAP.	

Tab	Table Name	Table	Table Title	Data quality	Fin / Non-fin	Data source	Methodology	Additional Comments
				🟩			All costs were directly allocated in line with the United Energy's approved Cost Allocation Methodology. ACS costs are calculated based on ACS revenue quantities multiplied by unit cost rates. **Operating Expenditure:** SAP download of every GL balance by cost centre which determine the line classifications and regulatory categories. Data generated from SAP. All costs were directly allocated in line with the United Energy's approved Cost Allocation Methodology. ACS costs are calculated based on ACS revenue quantities multiplied by unit cost rates	
		2	Operating and Maintenance Expenditure by purpose – Margins Only	🟩	F		SAP extract by ZNX Limb 2 has been deemed as related party margins.	
		3	Explanation of Material Difference	🟩	F	N/A	Analysed the makeup of the forecast and actual capital and compared the two. Qualitative analysis of difference between forecast and actual figures.	
9.5	TUos	No requirement to complete.						

Appendix D: UED Annual Financial Report – Financial year ended 31 December 2016

Note: See attached

United Energy Distribution Pty Ltd

ABN 70 064 651 029

Annual Financial Report
for the year ended 31 December 2016

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 2016.

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)

Principal activities

The principal activities of the Group during the course of the financial year consisted of the distribution of electricity from Victoria's transmission network to the premises of residential, commercial and industrial electricity users enabled via the ongoing construction, augmentation and maintenance of its electricity network in Victoria, Australia.

Dividends

No dividends were declared or paid during the year ended 31 December 2016 (2015: nil).

Review of operations

The review of operations covers the year from 1 January 2016 to 31 December 2016.

The profit from ordinary activities after income tax amounted to $43,623k (2015: $85,216k).

Consolidated revenue for the period was $637,560k (2015: $679,230k). Of this figure, electricity distribution revenue amounted to $503,105k (2015: $535,391k). The network distributed 7,721 GWh (2015: 7,632 GWh) of electricity during the year.

As at 31 December 2016, the Group has a net current asset deficiency of $651m. The main drivers are: (i) the reclassification of USPP US$365m (A$495.4m) due in December 2017 from non-current to current liability (ii) the reclassification of A$265m Fixed Rate Notes due in April 2017 from non-current to current liability and (iii) Net current derivatives fair value asset of (A$119m). Despite this deficiency, UED expects to continue to meet its obligations as they fall due on the basis that UEDH is confident of being able to complete its planned FY17 refinancings and forecasts positive operating cash flows. The Directors expect that UED's operations will continue as a going concern.

Matters subsequent to the end of the financial year

No matter or circumstance has arisen since 31 December 2016 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.

Matters subsequent to the end of the financial year (continued)

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 2016.

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 3.

Rounding of amounts

The company is of a kind referred to in ASIC Corporations (Rounding in Financial / Directors' Reports) Instrument 2016/191, 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 2016

Contents

United Energy Distribution Pty Ltd
Consolidated income statement
For the year ended 31 December 2016

	Notes	Consolidated entity Year ended 31 December 2016 $'000	 31 December 2015 $'000
Revenue from continuing operations	4	**637,560**	679,230
Expenses			
Loss on retirement of property, plant and equipment		**(4,369)**	(4,193)
Grid fees		**(112,488)**	(115,656)
Jurisdictional Scheme expenses		**(17,325)**	(18,509)
Operating fees		**(63,295)**	(57,387)
IT expenses		**(19,843)**	(22,179)
Other expenses		**(28,331)**	(25,781)
Depreciation and amortisation expense	5	**(146,274)**	(141,462)
Employee expenses		**(34,052)**	(29,937)
Consulting expenses		**(11,499)**	(13,007)
Unrealised foreign exchange gain/loss		**(58)**	143
Finance costs	5	**(140,000)**	(131,819)
Total expenses		**(577,534)**	(559,787)
Profit before income tax		**60,026**	119,443
Income tax (expense)/benefit	6	**(16,403)**	(34,227)
Profit for the period		**43,623**	85,216
Profit is attributable to:			
Owners of United Energy Distribution Pty Ltd		**43,623**	85,216

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 2016

		Consolidated entity Year ended	
		31 December	31 December
		2016	2015
	Notes	**$'000**	$'000
Profit for the period		**43,623**	85,216
Other comprehensive income			
Items that may reclassified to profit or loss in subsequent periods			
Changes in the fair value of cash flow hedges			
- Gains / (loss) taken to equity	22(a)	**31,494**	15,885
- Transferred to Income Statement	22(a)	**3,519**	(39,808)
Income tax on changes in the fair value of cash flow hedge		**(10,504)**	7,177
Other comprehensive income for the period, net of tax		**24,509**	(16,746)
Total comprehensive income for the period		**68,132**	68,470
Total comprehensive income for the period is attributable to:			
Owners of United Energy Distribution Pty Ltd		**68,132**	68,470
Total comprehensive income for the period attributable to owners of United Energy Distribution Pty Ltd arises from:			
Continuing operations		**68,132**	68,470

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

United Energy Distribution Pty Ltd
Consolidated balance sheet
As at 31 December 2016

	Notes	Consolidated entity 31 December 2016 $'000	31 December 2015 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	**36,577**	28,514
Trade and other receivables	8	**80,544**	95,003
Inventories	9	**6,554**	6,640
Derivative financial instruments	10	**131,551**	18,431
Total current assets		**255,226**	148,588
Non-current assets			
Receivables	11	**1,282,221**	1,279,368
Derivative financial instruments	10	**18,937**	116,208
Property, plant and equipment	12	**2,203,820**	2,113,598
Deferred tax assets	14	**55,983**	51,336
Intangible assets	13	**449,471**	464,701
Total non-current assets		**4,010,432**	4,025,211
Total assets		**4,265,658**	4,173,799
LIABILITIES			
Current liabilities			
Trade and other payables	15	**126,496**	120,261
Borrowings	16	**758,739**	274,350
Derivative financial instruments	10	**12,177**	7,273
Provisions	17	**8,721**	6,073
Total current liabilities		**906,133**	407,957
Non-current liabilities			
Borrowings	18	**1,617,903**	2,138,554
Derivative financial instruments	10	**37,956**	11,539
Deferred tax liabilities	19	**170,189**	150,465
Provisions	17	**2,702**	2,748
Other non-current liabilities	20	**167,514**	167,407
Total non-current liabilities		**1,996,264**	2,470,713
Total liabilities		**2,902,397**	2,878,670
Net assets		**1,363,261**	1,295,129
EQUITY			
Contributed equity		**646,459**	646,459
Other reserves	22(a)	**(10,810)**	(35,319)
Retained earnings	22(b)	**727,612**	683,989
Total equity		**1,363,261**	1,295,129

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 2016

	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 2015	646,459	(18,573)	598,773	1,226,659	1,226,659
Profit for the year	-	-	85,216	85,216	85,216
Total comprehensive income for the period	**-**	**-**	**85,216**	**85,216**	**85,216**
Transactions with owners in their capacity as owners:					
Effective portion of changes in cash flow hedge, net of tax	-	(16,746)	-	(16,746)	(16,746)
Balance at 31 December 2015	**646,459**	**(35,319)**	**683,989**	**1,295,129**	**1,295,129**
Balance at 1 January 2016	646,459	(35,319)	683,989	1,295,129	1,295,129
Profit for the year	-	-	43,623	43,623	43,623
Total comprehensive income for the period	**-**	**-**	**43,623**	**43,623**	**43,623**
Transactions with owners in their capacity as owners:					
Effective portion of changes in cash flow hedge, net of tax	-	24,509	-	24,509	24,509
Balance at 31 December 2016	**646,459**	**(10,810)**	**727,612**	**1,363,261**	**1,363,261**

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

United Energy Distribution Pty Ltd
Consolidated statement of cash flows
For the year ended 31 December 2016

		Consolidated entity	
		Year ended	
		31 December 2016	31 December 2015
	Notes	**$'000**	$'000
Cash flows from operating activities			
Receipts from customers (inclusive of goods and services tax)		**766,189**	741,712
Payments to suppliers and employees (inclusive of goods and services tax)		**(351,917)**	(361,416)
Intercompany receipts / (payments) with UEDH group		**(59,104)**	55,696
		355,168	435,992
Net cash inflow from operating activities	27	**355,168**	435,992
Cash flows from investing activities			
Payments for property, plant and equipment		**(201,355)**	(216,913)
Proceeds from sale of property, plant and equipment		**1,401**	1,876
Payment for intangibles		**(23,082)**	(30,571)
Net cash (outflow) from investing activities		**(223,036)**	(245,608)
Cash flows from financing activities			
Finance costs paid		**(137,963)**	(174,635)
Interest received		**723**	771
Net external borrowings		**13,171**	(10,214)
Net cash (outflow) from financing activities		**(124,069)**	(184,078)
Net increase in cash and cash equivalents		**8,063**	6,306
Cash and cash equivalents at the beginning of the financial year		**28,514**	22,208
Cash and cash equivalents at end of period	7	**36,577**	28,514

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 in Note 1 (x). The financial statements are for the consolidated entity consisting of United Energy Distribution Pty Ltd and its subsidiaries.

(a) Financial reporting framework

The Company is not a reporting entity because in the opinion of the directors, it is unlikely that users of the financial report 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 8: Segment Reporting
AASB 9 (2014): Financial Instruments
AASB 12: Disclosure of Interests in Other Entities
AASB 13: Fair Value Measurement
AASB 102: Inventories
AASB 112: Income Taxes
AASB 116: Property, Plant and Equipment
AASB 117: Leases
AASB 119: Employee Benefits
AASB 124: Related Party Disclosures
AASB 132: Financial Instruments: Presentation
AASB 136: Impairment of Assets
AASB 137: Provisions, Contingent Liabilities and Contingent Assets
AASB 138: Intangible Assets
AASB 139: Financial Instruments: Recognition and Measurement

(b) Basis of preparation

As at 31 December 2016, the Group has a net current asset deficiency of $651m. The main drivers are: (i) the reclassification of USPP US$365m (A$495.4m) due in December 2017 from non-current to current liability (ii) the reclassification of A$265m Fixed Rate Notes due in April 2017 from non-current to current liability and (iii) Net current derivatives fair value asset of (A$119m). Despite this deficiency, UED expects to continue to meet its obligations as they fall due on the basis that UEDH is confident of being able to complete its planned FY17 refinancings and forecasts positive operating cash flows. The Directors expect that UED's operations will 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.

1 Summary of significant accounting policies (continued)

(b) Basis of preparation (continued)

(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.

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 2016 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.

1 Summary of significant accounting policies (continued)

(d) Foreign currency translation (continued)

(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.

Foreign exchange gains and losses that relate to borrowings are presented in the consolidated income statement, within finance costs. All other foreign exchange gains and losses are presented in the consolidated income statement on a net basis within other income or other expenses.

(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) Electricity distribution revenue
Electricity distribution revenue earned from the use of the distribution network is recognised when electricity and related services are provided. Accrued electricity distribution revenue is determined in respect of the period from a customer's last billing date and the customer's previous consumption patterns. Electricity distribution revenue includes the cost of transmission services charged by the transmission companies, which are 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) Meter revenue
Meter revenue is recovered under a Cost Recovery Order in Council. The revenue is recorded as it is earned from energy consumed.

(iv) 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.

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

1 Summary of significant accounting policies (continued)

(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.

(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.

1 Summary of significant accounting policies (continued)

(g) Income tax (continued)

(i) Tax consolidation
United Energy Distribution Holdings Pty Ltd is the head company in a tax consolidated group comprising it and its Australian wholly-owned subsidiaries of which United Energy Distribution Pty Ltd is a member. The implementation date for this tax consolidated 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.

(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.

1 Summary of significant accounting policies (continued)

(h) Impairment of assets (continued)

(ii) Non-financial assets
The carrying amounts of the consolidated entity's non-financial assets, other than inventories and deferred tax assets, are reviewed 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 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.

(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.

Collectability of trade debtors is reviewed on an ongoing basis. Debts which are known to be uncollectable 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.

1 Summary of significant accounting policies (continued)

(l) Derivatives and hedging activities

(i) Derivative financial instruments
Derivative financial instruments are recognised initially at fair value and subsequently remeasured at fair value each reporting date. The gain or loss on remeasurement to fair value is recognised immediately in profit or loss. However, where derivatives qualify for hedge accounting, recognition of any resultant gain or loss depends on the nature of the item being hedged.

Hedge accounting is a technique that enables the matching of the gains and losses on the hedged items and the associated hedging instruments in the same accounting period to minimise volatility in the income statement. The gain or loss on the underlying item (the "hedged item") is expected to move in the opposite direction to the gain or loss on the derivative (the "hedging instrument"), therefore offsetting the risk position.

To the extent permitted by AASB 9, we formally designate and document financial instruments as fair value, cash flow or net investment hedges for accounting purposes. In order to qualify for hedge accounting, AASB 9 requires that prospective hedge effectiveness testing meet all of the following criteria:

- an economic relationship exists between the hedged item and hedging instrument
- the effect of credit risk does not dominate the value changes resulting from the economic relationship
- the hedge ratio is the same as that resulting from actual amounts of hedged items and hedging instruments for risk management.

The fair value of interest rate swaps, cross currency swaps and forward exchange contracts is the estimated amount that a market participant would receive or pay to transfer the swap at the reporting date, taking into account current interest and foreign exchange rates and the current creditworthiness of the swap counterparties and the Group.

(ii) Fair value hedge
Where a derivative financial instrument hedges the changes in fair value of a recognised asset or liability or an unrecognised firm commitment (or an identified portion of such assets, liability or firm commitment), any gain or loss on the hedging instrument is recognised in profit or loss. The hedged item also is restated at fair value in respect of the risk being hedged, with any gain or loss being recognised in profit or loss. The ineffective portion of the hedge is within other income or other expense. The effective portion is within the same category of the fair value of the hedged item.

1 Summary of significant accounting policies (continued)

(iii) Cash flow hedge
Where a derivative financial instrument is designated as a hedge of the variability in cash flows of a recognised asset or liability, or a highly probable forecasted transaction, the effective part of any gain or loss on the derivative financial instrument is recognised directly in equity. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss within other income or other expense.

Amounts accumulated in equity are reclassified to profit and loss in the periods when the hedged item affects profit or loss.

When the forecast transaction subsequently results in the recognition of a non financial asset or non financial liability, the associated cumulative gain or loss is removed from equity and included in the initial cost or other carrying amount of the non financial asset or liability. If a hedge of a forecast transaction subsequently results in the recognition of a financial asset or a financial liability, the associated gains and losses that were recognised directly in equity are reclassified into profit or loss in the same period or periods during which the asset acquired or liability assumed affects profit or loss (i.e. when interest income or expense is recognised).

When a hedging instrument expires or is sold, terminated or exercised, or the entity revokes designation of the hedge relationship, but the hedged forecast transaction is still expected to occur, the cumulative gain or loss at that point remains in equity and is recognised in accordance with the above policy when the transaction occurs. If the hedged transaction is no longer expected to take place, the cumulative unrealised gain or loss recognised in equity is recognised immediately in profit or loss.

(iv) Hedging strategy
The Group's major exposure to interest rate risk and foreign currency risk arises from our long term borrowings. The Group enters into cross currency swaps, interest rate swaps and forward exchange contracts to offset these risks. The instruments used by the Group are as follows:

Interest rate swap contracts and forward exchange contracts - cash flow hedges

The Group uses interest rate swap contracts to manage its exposure to variable interest rates related to borrowings. Interest rate swap contracts currently in place cover 91.3% (2015: 92.0%) of the variable interest rate debt held by the Group (excluding working capital facilities).

The Group currently uses forward exchange contracts to protect against exchange rate movements between the AUD and foreign currencies. The Group has hedged a portion of its USD denominated payment obligations.

All cash flow hedges are regarded as effective economic relationships on the basis that the critical terms of the hedging instrument and hedged item are aligned (including face values, cash flows and currency). During the year, there has been $2.2m ineffectiveness attributable to our cash flow hedges.

The Group has established a hedge ratio of 1:1 for its interest rate and forward exchange hedging relationships. Potential sources of hedge ineffectiveness that may affect the hedging relationship during the term are alignment of re-pricing and repayment dates.

1 Summary of significant accounting policies (continued)

Cross-currency interest rate contracts - fair value hedges
The Group has entered into cross-currency interest rate swap contracts to remove the risk of unfavourable exchange rate movements on borrowings held in USD. Under these contracts, the Group receives foreign currency at fixed rates and pays AUD at floating rates. The Group then uses separate interest rate swap contracts to hedge the floating interest rate commitments back to fixed interest rates in cash flow hedge relationships as described above.

The Group's fair value hedges have an economic relationship on the basis that the critical terms of the hedging instrument and hedged item (including face value, cash flows, and maturity date) are aligned.

The Group has established a hedge ratio of 1:1 for its cross currency hedging relationships. Potential sources of hedge ineffectiveness that may affect the hedging relationship during the term are alignment of re-pricing and repayment dates.

Offsetting financial assets and financial liabilities
Currently there is no legal right of set-off to present any financial assets or financial liabilities on a net basis, and as such no financial assets or financial liabilities have been presented on a net basis in the Group's balance sheet at the end of the financial year.

(v) Fair Value Hierarchy
The fair value measurements of financial assets and liabilities are assessed in accordance with the following hierarchy:

- Quoted prices (unadjusted) in active markets for identical assets and liabilities (Level 1);
- Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (as prices) or indirectly (derived from prices) (Level 2); and
- Inputs for the asset or liability that are not based on observable market date (Level 3).

For assets and liabilities that are recognised on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by re-assessing categorisation (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period. There were no transfers in the current year.

(vi) Valuation techniques for financial assets and liabilities
The carrying value of all current receivable and payable balances approximates their fair value. This is generally the case of all borrowings, except for redeemable preference shares, because the interest payable on those borrowings is close to market rates or of a short term nature.

The fair value, calculated for disclosure purposes only, of certain non-current interest bearing liabilities held at amortised cost is calculated as the present value of expected future cash flows. These are identified as Level 2.

Derivative financial instruments are identified as Level 2. The fair value of a swap is calculated as its present value, i.e. the sum of all the discounted future cash flows for both the fixed leg and floating leg, discounted using a current borrowing rate.

(vii) Valuation techniques for debt held at fair value
Certain non-current liabilities are held at fair value as opposed to amortised cost. This debt has one series of cash flows which includes the payment of interest on the principal and the repayment of the principal itself. Interest rates applicable to the debt can be either floating (adjusted for margin where applicable) or fixed.

The series of cash flows is discounted using the same methodology as discounting a series of cashflows for an interest rate swap as noted above.

Where foreign currency debt is held, the series of cashflows is translated to Australian dollars (which is the functional currency of each entity within the group) using the appropriate foreign exchange rates at valuation date as observed in the market.

1 Summary of significant accounting policies (continued)

(viii) Credit risk adjustment
In valuing over-the-counter derivatives, and debt at fair value, allowance is made for the impact of credit risk, where one party may default on the obligatory payments to the other party. Each counterparty is subject to the credit risk of the other counterparty.

An appropriate credit spread is used when determining the magnitude of the credit value adjustment. This credit spread is sourced from a traded credit default swap spread, any recent debt issuance from the relevant counterparty or from an index credit default swap spread based on the relevant counterparty's credit rating.

Bilateral collateral arrangements, master netting agreements and other credit enhancement or risk mitigation tools reduce the credit exposure associated with an asset or liability and are considered in determining the fair value of the liability.

(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	7 - 50 years
- Vehicles	5 - 10 years
- Office equipment	3 - 15 years
- Furniture, fixtures and fittings	3 - 13 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.

(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.

1 Summary of significant accounting policies (continued)

(n) Intangible assets (continued)

(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 1 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 deposits

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

All borrowings and loans are initially recognised at fair value, net of transaction costs incurred. Borrowings are subsequently measured at amortised cost using the effective interest method, except for borrowings designated in fair value hedge relationships which are measured at fair value. Any difference between the proceeds (net of transaction costs) and the redemption amount is recognised in the income statement over the period of the borrowings using the effective interest method.

The Group enters into derivatives arrangements in respect of interest bearing liabilities. The accounting policies are as described in the derivative financial instruments Note 1 (l).

Subsequent fair value adjustments are made to borrowings to reflect the portion that is designated in fair value hedge relationships. The gain or loss as a result of this change is recorded in the profit or loss.

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

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.

(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.

1 Summary of significant accounting policies (continued)

(r) Provisions (continued)

(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 depending 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 contributed equity. The terms and conditions of various classes of equities affecting income or capital entitlements are detailed in note 21.

(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.

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.

1 Summary of significant accounting policies (continued)

(w) Comparative figures

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

(x) New accounting standards and interpretations

The Group applied several mandatory amendments for the first time in financial year 2016. They are as follows:

AASB 2013-9 *Amendments to Australian Accounting Standards - Conceptual Framework, Materiality and Financial Instruments*

AASB 2015-3 *Amendments to Australian Accounting Standards arising from the Withdrawal of AASB 1031 Materiality*

The adoption of these new standards did not have a significant impact on the financial statements or performance of the Group.

AASB 9 Financial Instruments was early adopted for the first time in financial year 2016. The impact of the adoption of this standard is disclosed in Note 1(l).

Accounting Standards and Interpretations issued but not yet effective

Certain new standards, amendments and interpretations to existing standards have been published that are mandatory for accounting periods beginning on or after 1 July 2016 or later periods but which have not yet been adopted. The significant changes and an assessment of the impact of these are as follows. Other new standards, amendments and interpretations to existing standards are not expected to have a significant impact on the financial statements or performance of the Group.

AASB15 Revenue from Contracts with Customers includes requirements to recognise revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for these goods or services. The Group is currently assessing the impact of adopting this standard. The application date of this standard for the Group is 1 July 2018.

AASB16 Leases includes requirements to recognise assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. The Group is currently assessing the impact of adopting this standard. The application date of this standard for the Group is 1 July 2019.

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 purchases.

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, 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, the Group 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 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) Meter revenue
Meter revenue is recovered under a Cost Recovery Order in Council. The revenue is recorded as it is earned from energy consumed.

(iv) 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** **2016** **$'000**	 31 December 2015 $'000
From continuing operations		
Distribution revenue	**503,105**	535,391
Other services	**132,824**	140,556
Miscellaneous revenue	**908**	2,478
Foreign exchange (loss) / gains	**-**	34
	636,837	678,459
Other revenue		
Interest - external	**723**	771
	637,560	679,230

5 Expenses

	Consolidated entity **Year ended** **31 December** **2016** **$'000**	 31 December 2015 $'000
Profit before income tax includes the following specific expenses:		
Depreciation		
Buildings	**360**	360
Plant and equipment	**106,481**	98,373
Total depreciation	**106,841**	98,733
Amortisation		
Software	**27,162**	28,926
Deferred expenditure	**12,271**	13,803
Total amortisation	**39,433**	42,729
Total depreciation and amortisation	**146,274**	141,462
Finance costs		
Related parties	**39,101**	38,994
Other corporations	**100,899**	92,825
	140,000	131,819

6 Income tax expense

(a) Income tax expense

	Consolidated entity	
	Year ended	
	31 December 2016 $'000	31 December 2015 $'000
Current tax	**11,830**	3,739
Deferred tax	**4,573**	30,488
	16,403	34,227
Income tax expense is attributable to:		
Profit from continuing operations	**16,403**	34,227
Deferred income tax expense included in income tax expense comprises:		
(Increase) decrease in deferred tax assets (note 14)	**(15,151)**	(4,301)
(Decrease) increase in deferred tax liabilities (note 19)	**19,724**	34,789
	4,573	30,488

(b) 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 tax consolidated 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 Interpretations 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 2016 $'000	31 December 2015 $'000
Cash at bank and in hand	**36,577**	28,295
Other cash and cash equivalents	**-**	219
	36,577	28,514

(a) Terms and conditions

Cash is held at call and earns an average interest rate of 1.80% (2015: 2.06%) per annum.

8 Current assets - Trade and other receivables

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Trade receivables (a) (i)	**5,800**	5,650
Provision for impairment of receivables	**(1,636)**	(1,012)
	4,164	4,638
Other receivables	**57,640**	71,594
Prepayments	**15,830**	12,585
Interest receivables (a) (ii)	**2,910**	6,186
	18,740	18,771
	80,544	95,003

(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 interest rate swaps - $2,910K.

9 Current assets - Inventories

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Transformers	**3,871**	3,855
AMI meters	**2,683**	2,785
	6,554	6,640

10 Derivative financial instruments

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Current assets		
Derivative financial instruments	**131,551**	18,431
Total current derivative financial instrument assets	**131,551**	18,431
Non-current assets		
Derivative financial instruments	**18,937**	116,208
Total non-current derivative financial instruments	**18,937**	116,208
Current liabilities		
Derivative financial instruments	**(12,177)**	(7,273)
Total current derivative financial instrument liabilities	**(12,177)**	(7,273)
Non-current liabilities		
Derivative financial instruments	**(37,956)**	(11,539)
Total non-current derivative financial instrument liabilities	**(37,956)**	(11,539)
	100,355	115,827

11 Non-current assets - Receivables

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Receivables from controlling entities	**1,282,221**	1,279,368

(a) Receivables from controlling 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 $15M with related parties. These receivables are non-interest bearing and are generally settled on call.

12 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 2015					
Cost or fair value	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
Year ended 31 December 2015					
Opening net book amount	2,658	4,698	1,838,781	157,386	2,003,523
Additions	-	278	147,736	67,397	215,411
Depreciation charge	-	(360)	(98,373)	-	(98,733)
Disposals - at cost	-	-	(5,986)	-	(5,986)
Transfers (to)/from intangible assets	-	378	114,861	(115,856)	(617)
Closing net book amount	2,658	4,994	1,997,019	108,927	2,113,598
At 31 December 2015					
Cost or fair value	2,658	8,677	2,990,055	108,927	3,110,317
Accumulated depreciation	-	(3,683)	(993,036)	-	(996,719)
Net book amount	2,658	4,994	1,997,019	108,927	2,113,598
Year ended 31 December 2016					
Opening net book amount	2,658	4,994	1,997,019	108,927	2,113,598
Additions	-	129	146,554	58,621	205,304
Depreciation charge	-	(360)	(106,481)	-	(106,841)
Disposals - at cost	-	-	(5,770)	-	(5,770)
Transfers (to)/from intangible assets	-	57	82,189	(84,717)	(2,471)
Closing net book amount	2,658	4,820	2,113,511	82,831	2,203,820
At 31 December 2016					
Cost	2,658	8,863	3,202,975	82,831	3,297,327
Accumulated depreciation	-	(4,043)	(1,089,464)	-	(1,093,507)
Net book amount	2,658	4,820	2,113,511	82,831	2,203,820

13 Non-current assets - Intangible assets

Consolidated entity	**Software** **$'000**	**AMI & other intangibles** **$'000**	**Licence** **$'000**	**Total** **$'000**
At 1 January 2015				
Cost	240,306	97,354	357,200	694,860
Accumulation amortisation and impairment	(161,786)	(56,133)	-	(217,919)
Net book amount	78,520	41,221	357,200	476,941
Year ended 31 December 2015				
Opening net book amount	78,520	41,221	357,200	476,941
Additions - acquisition	27,545	2,410	-	29,955
Amortisation charge	(28,926)	(13,803)	-	(42,729)
Transfers (to)/ from property, plant & equipment	1,962	(1,345)	-	617
Disposals -costs	(83)	-	-	(83)
Closing net book amount	79,018	28,483	357,200	464,701
Cost	254,586	98,287	357,200	710,073
Accumulation amortisation and impairment	(175,568)	(69,804)	-	(245,372)
Net book amount	79,018	28,483	357,200	464,701
Consolidated entity				
Year ended 31 December 2016				
Opening net book amount	79,018	28,483	357,200	464,701
Additions - acquisition	19,838	1,894	-	21,732
Amortisation charge	(27,162)	(12,271)	-	(39,433)
Transfers (to)/ from property, plant & equipment	(255)	2,726	-	2,471
Closing net book amount	71,439	20,832	357,200	449,471
At 31 December 2016				
Cost	273,035	102,908	357,200	733,143
Accumulated amortisation	(201,596)	(82,076)	-	(283,672)
Net book amount	71,439	20,832	357,200	449,471

14 Non-current assets - Deferred tax assets

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Doubtful debts	**491**	304
Derivative financial instruments	**42,702**	42,425
Environmental	**811**	825
Intellectual property	**5,119**	4,638
Other	**6,860**	3,144
	55,983	51,336

	Consolidated entity	
Movements:		
Opening balance	**51,336**	40,536
Charged/(credited):		
- to profit or loss	**15,151**	4,301
- directly to equity	**(10,504)**	6,499
	55,983	51,336

15 Current liabilities - Trade and other payables

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Trade payables and accruals	**71,386**	63,030
Customer deposits	**19,648**	19,392
Accrued interest	**30,639**	32,627
Other payables	**1**	3
Payables to controlling entity	**3,363**	3,680
Goods and services tax (GST) (receivable)/ payable	**1,459**	1,529
	126,496	120,261

(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.

16 Current liabilities - Borrowings

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Unsecured		
Guaranteed notes and loan notes	**758,739**	274,350
Total unsecured current borrowings	**758,739**	274,350

(a) Guaranteed notes and loan notes

UED raised US$365m through a US Private Placement in December 2010, fixed interest at 5.01% for seven years, maturing 15 December 2017.

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

17 Provisions

	Consolidated entity					
	31 December 2016			31 December 2015		
	Current $'000	**Non-current $'000**	**Total $'000**	Current $'000	Non-current $'000	Total $'000
AMI rebate provision	**-**	**-**	**-**	33	-	33
Claims costs	**548**	**-**	**548**	941	-	941
Employee related provisions	**8,173**	**-**	**8,173**	5,099	-	5,099
Environmental provision	**-**	**2,702**	**2,702**	-	2,748	2,748
	8,721	**2,702**	**11,423**	6,073	2,748	8,821

(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).*

A comprehensive review of the contaminated land risk management project was performed in the year and has resulted in the reduction of the provisions that have been allocated to respond to inherent environmental liabilities on the network.

18 Non-current liabilities - Borrowings

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Unsecured		
Subordinated loans from controlling entities (a)	**263,472**	263,472
Guaranteed notes (b)	**238,160**	761,108
Bank loans (c)	**757,000**	814,500
Loan notes (d)	**365,957**	306,811
Deferred borrowing costs	**(6,686)**	(7,337)
Total unsecured non-current borrowings	**1,617,903**	2,138,554

(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.

18 Non-current liabilities - Borrowings (continued)

(b) Guaranteed notes

UED raised US$100m through a US Private Placement in September 2015, fixed interest at 3.28%, maturing 13 October 2022.

UED raised US$74m through a US Private Placement in September 2015, fixed interest at 3.59%, maturing 13 October 2025.

(c) Bank loans

The following loan facilities are unsecured:

Asian Debt - $200M (maturity: 11 April 2019), interest BBSY plus margin 1.10%.
Asian Debt - $200M (maturity: 11 October 2021), interest BBSY plus margin 1.50%.
Revolving Syndicated Facility - $305m (maturity: 11 April 2020), interest BBSY plus margin 1.25%.
Revolving Syndicated Facility - $77m (maturity: 20 May 2019), interest BBSY plus margin 1.30%.
Revolving Syndicated Facility - $120m (maturity: 27 February 2020), interest BBSY plus margin 1.35%.
Capex Facility - $150m (maturity: 11 April 2018), interest BBSY plus margin 1.00%
Revolving Syndicated Facility - $250m (maturity: 28 October 2021), interest BBSY plus margin 1.60%

(d) Loan notes

UED raised A$42m through a US Private Placement in September 2015, fixed interest at 4.79%, maturing 13 October 2025.
UED raised A$350m Fixed rate notes in September 2016, fixed interest at 3.5%, maturing on 12 September 2023.

19 Non-current liabilities - Deferred tax liabilities

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
The balance comprises temporary differences attributable to:		
Intangible assets	**2,260**	4,203
Property, plant and equipment	**116,127**	102,059
Derivative financial instruments	**51,757**	41,869
Other	**45**	2,334
	170,189	150,465

	Consolidated entity	
Movements:		
Opening balance	**150,465**	116,354
Charged/(credited):		
- profit or loss	**19,724**	34,789
- directly to equity	**-**	(678)
	170,189	150,465

20 Non-current liabilities - Other non-current liabilities

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Payables to controlling entity	**167,514**	167,407
	167,514	167,407

(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 18).

21 Contributed equity

(a) Share capital

	31 December 2016 Shares	31 December 2015 Shares	**31 December 2016 $'000**	31 December 2015 $'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.

22 Other reserves and retained earnings

(a) Other reserves

	Consolidated entity	
	31 December 2016 $'000	31 December 2015 $'000
Cash flow hedges	**(10,810)**	(35,319)
	(10,810)	(35,319)

22 Other reserves and retained earnings (continued)

(a) Other reserves (continued)

Movements:

Cash flow hedges			
Opening balance		**(35,319)**	(18,573)
Revaluation - gross	10	**35,013**	(23,923)
Deferred tax	6, 14, 19	**(10,504)**	7,177
Balance 31 December		**(10,810)**	(35,319)

Hedge reserve - cash flow hedge reserve

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.

(b) Retained earnings

Movements in retained earnings were as follows:

	Consolidated entity **31 December 2016** **$'000**	 31 December 2015 $'000
Balance 1 January	**683,989**	598,773
Net profit for the period	**43,623**	85,216
Balance 31 December	**727,612**	683,989

23 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** **2016** **$**	 2015 $
Audit and other assurance services		
Audit and review of financial statements	**117,025**	124,400
Other assurance services		
Audit of regulatory returns	**359,163**	341,700
Other services	**12,300**	16,300
	371,463	358,000
Total remuneration for audit and other assurance services	**488,488**	482,400

24 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 2016.

The Group had no material contingent liabilities or assets at 31 December 2016 (2015: nil).

25 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:	
	2016 **%**	2015 %
UE & Multinet Pty Ltd	**50**	50

26 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 1:

Name of entity	**Country of incorporation**	**Class of shares**	**Equity holding**	
			2016 **%**	2015 %
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

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

	Consolidated entity **Year ended** **31 December 2016** **$'000**	 31 December 2015 $'000
Profit for the period	**43,623**	85,216
Depreciation and amortisation	**146,274**	141,462
Net (gain) loss on sale of non-current assets	**4,369**	4,193
Customer contribution in kind	**(14,848)**	(6,808)
Discount on loan	**151**	151
Finance cost paid	**137,963**	174,635
Interest received	**(723)**	(771)
Change in operating assets and liabilities:		
(Increase) in trade debtors and bills of exchange	**10,619**	50,933
(Increase) in inventories	**85**	(278)
(Increase) decrease in deferred tax assets	**(4,647)**	(4,301)
(Decrease) increase in trade creditors	**17,481**	1,888
(Decrease) increase in deferred tax liabilities	**9,221**	34,789
(Decrease) increase in other provisions	**2,603**	(198)
(Decrease) increase in derivative financial instruments	**2,997**	(44,919)
Net cash inflow (outflow) from operating activities	**355,168**	435,992

In the directors' opinion:

(a) the financial statements and notes set out on pages 4 to 40 are in accordance with the accounting policies described in Note 1 to the financial statements, including:
  (i) complying with Accounting Standards and other mandatory professional reporting requirements, to the extent described in Note 1 to the financial statements, and
  (ii) present fairly, the consolidated entity's financial position as at 31 December 2016 and its financial performance and cash flows 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.

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	637,560	579,299	58,262

Explanation of difference

Details	Amount
Pole Rental	5,755
Interest	723
Customer Contributions	50,674
Interval Meter Provision Charges > 160Mwh	88
Burwood Depot and Other Property Rental	329
Optus Wire Down and Other Miscellaneous Revenue	693
TOTAL	**58,262**

Operating expenditure

	Statutory Accounts	Regulatory Accounts	Difference
TOTAL	**157,076**	**156,422**	**654**

Explanation of difference

Details	Amount
Provision for Optus Doubtful Debts	654
TOTAL	**654**

Capital expenditure

No difference between statutory and regulatory accounts.

Appendix F: Accounting policies and principles

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:

- 2016 to 2020 Distribution determination
- 2016 to 2020 Public lighting determination
- 2016 to 2020 AMI Final Decision

These decisions provide the benchmarks against which actual expenditure is measured against, opening regulatory asset bases and depreciation allowances for the 2016 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

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		TOTAL	SCS	AMI	ACS	Public Lighting	Negotiated Services		TOTAL	
Network Operating Costs	19,102		151				**19,253**	0	0	0	0	0	0	0	**19,253**
GSL payments	714						**714**	0	0	0	0	0	0	0	**714**
AMI		6,016					**6,016**	0	0	0	0	0	0	0	**6,016**
Customer Service	7,384	199	1,703				**9,286**	0	0	0	0	0	0	0	**9,286**
Billing and Revenue Collection	2,554						**2,554**	0	0	0	0	0	0	0	**2,554**
CEO	2,923						**2,923**	0	0	0	0	0	0	0	**2,923**
Commercial	5,914						**5,914**	0	0	0	0	0	0	0	**5,914**
Corporate Affairs	965						**965**	0	0	0	0	0	0	0	**965**
Facilities	5,288						**5,288**	0	0	0	0	0	0	0	**5,288**
Finance	12,601	8	136				**12,745**	0	0	0	0	0	0	0	**12,745**
HR	1,469						**1,469**	0	0	0	0	0	0	0	**1,469**
Internal Audit	682						**682**	0	0	0	0	0	0	0	**682**

Appendix F: Accounting policies and principles

	Direct Allocation							Indirect Allocation							Overall opex TOTAL
	SCS	AMI	ACS	Public Lighting	Negotiated Services		TOTAL	SCS	AMI	ACS	Public Lighting	Negotiated Services		TOTAL	
Advanced Metering	316						**316**	0	0	0	0	0	0	0	**316**
Regulatory	2,087						**2,087**	0	0	0	0	0	0	0	**2,087**
Customer Innovation	6,902						**6,902**	0	0	0	0	0	0	0	**6,902**
IT	19,717	2,910					**22,627**	0	0	0	0	0	0	0	**22,627**
TOTAL	**88,618**	**9,133**	**1,990**	**0**	**0**	**0**	**99,741**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**99,741**

3. Cost Allocation Methodology

See attached document.

4. Capitalisation Policy

See attached document.

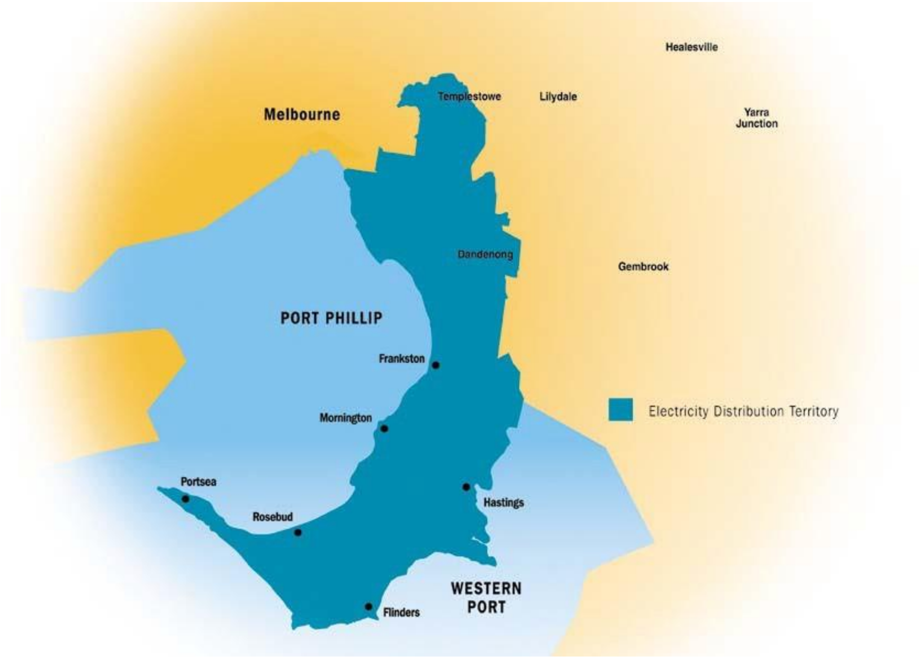
Cost Allocation Method

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].

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[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

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[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.

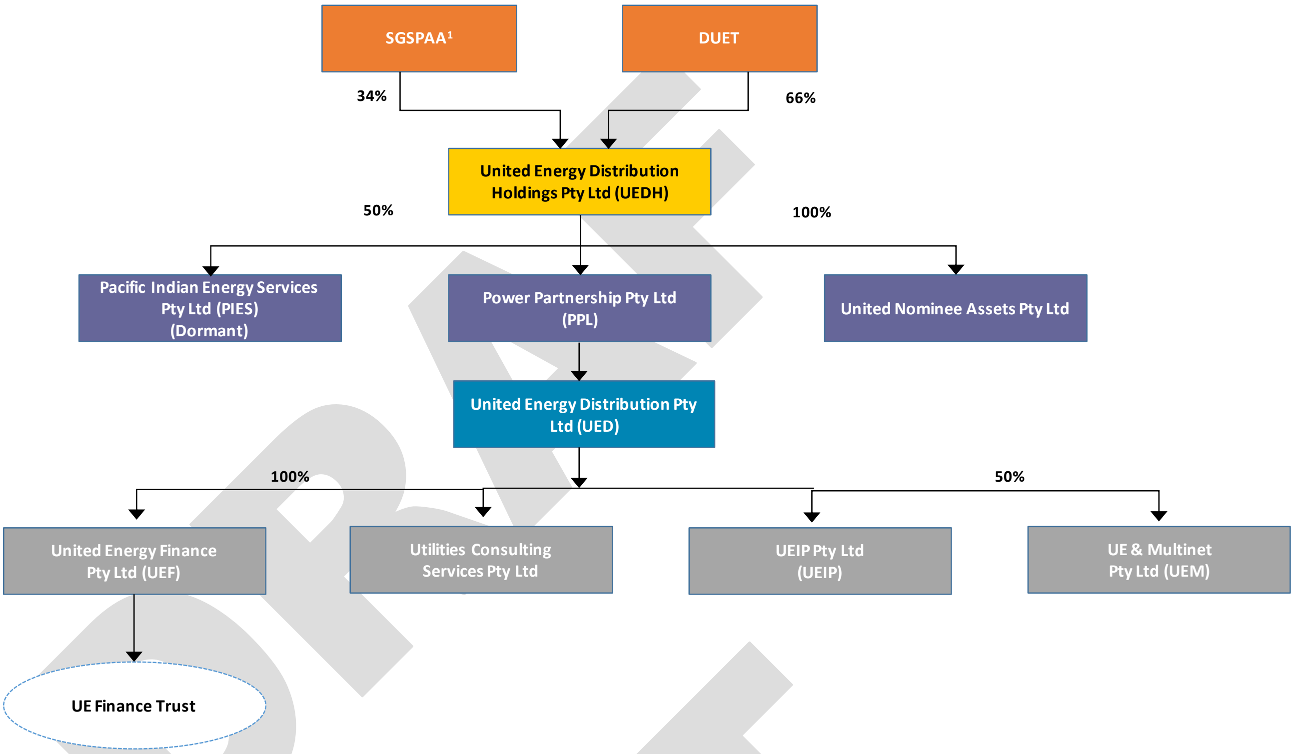
Responsibility for updating, maintaining and applying this CAM is with the CFO. The CFO is also responsible for internally monitoring and reporting on the application of this CAM.

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

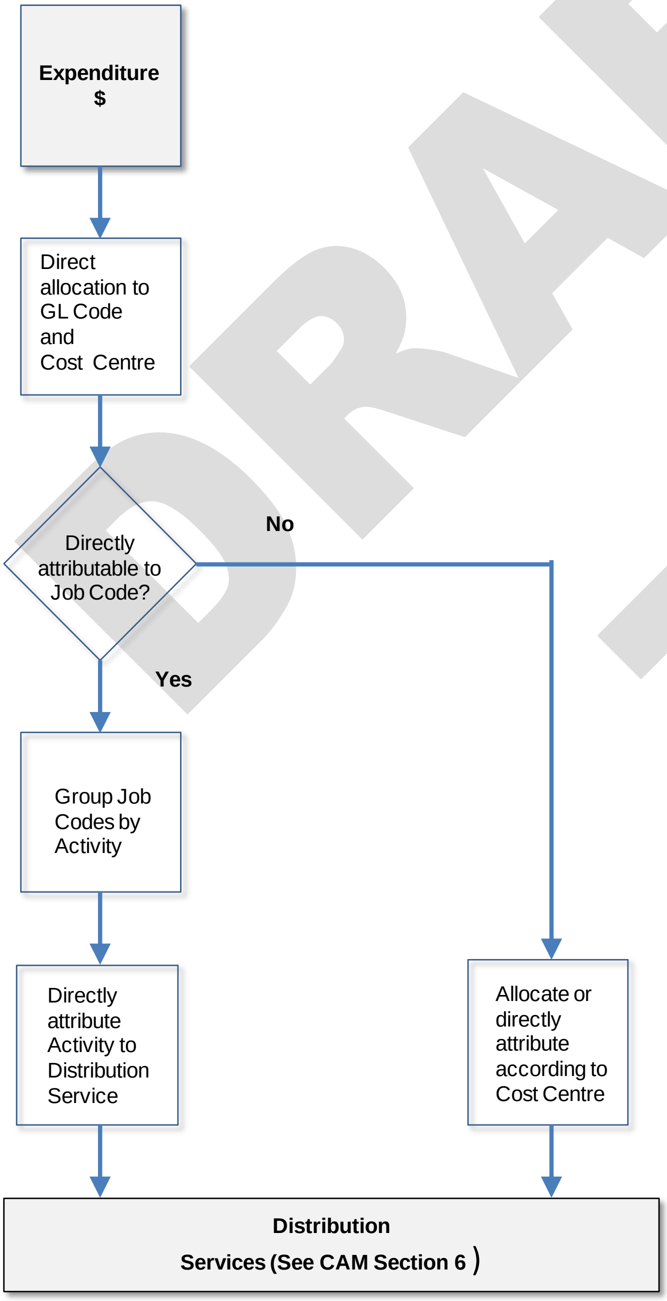
The changes in service classification described above are consistent with UE's response to the AER's preliminary views. UE will amend this section of the CAM in accordance with clause 4.2(a) of the CAG in order to apply the AER's final classification of services.

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.

UE Capitalisation Policy

Extracted from the UE Fixed Asset Procedure

Table of Contents

1 Procedure

1.1 Identifying Expenditure to be Capitalised

United Energy have 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 procedure 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 procedure, further guidance is required, contact the Fixed Asset Accountant.

Recognition Criteria:

There are different criteria for recognising tangible and intangible assets.

Tangible:

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[1]*.*

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[2]*.*

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

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[1] AASB 116, paragraph 7

[2] AASB 138, paragraph 11 to 24

the location and condition necessary for it to be capable of operating in the manner intended by management.[3] This will need to be assessed on an asset by asset basis as management intentions may change on completion of an asset. Refer to the 'Exception' under 'Information Services Expenditure Classification' section of this procedure 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 procedure.
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.
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.

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[3] AASB 116, paragraph 20

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.

1.2 Intangible Expenditure

Intangible project expenditure can be capitalised where they meet 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.

Computer software for a computer-controlled machine tool that cannot operate without that specific software is an integral part of the related hardware and is treated as PP&E. The same applies to the operating system of a computer. When the software is not an integral part of the related hardware, computer software is treated as an intangible asset.[4] This is usually referred to as application software.

The ability to capitalise intangible expenditure under AASB 138 is a two step process.[5]

The first step is for the expenditure to meet the identifiability criterion[6].

(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.

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[4] AASB 138, paragraph 4

[5] AASB 138, paragraph 18

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

The second step is for the expenditure to meet the recognition criteria[7]:

(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.

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.[8] 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. [9] Examples of research activities are[10]:
  i. activities aimed at obtaining new knowledge
  ii. the search for, evaluation and final selection of, applications of research findings or other knowledge
  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.[11] 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.[12] Examples of development activities are:[13]
  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.

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

[8] AASB 138, paragraph 8

[9] AASB 138, paragraphs 54 & 55

[10] AASB 138, paragraph 56

[11] AASB 138, paragraph 8

[12] AASB 138, paragraph 58

[13] AASB 138, paragraph 59

Expenditure relating to the development phase may be capitalised if the entity can demonstrate **all** of the following:[14]

(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.

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 hardware. This support is typically for a period between twelve 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.

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

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[14] AASB 138, paragraph 57

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.

Information Services Cloud Expenditure

Overview

Broadly, cloud services are computing services provided over the internet, and paid for as they are used.

In reality, solutions that utilise cloud services will often also include the creation of a capital asset as part of that solution.

- The solution may include an integration layer, so that the cloud services can interact with existing UE and MG systems. That integration layer is likely to be a capital asset.

- Or the solution may utilise some cloud services, but include built or licensed software capital assets of various kinds in addition to the cloud service.

So there will be components of the solution that need to be treated as Capex, and components that need to be treated as Opex.

General

Components of a solution that are cloud based, and paid for on a 'pay as you go' basis, are treated as Opex.

Components of a solution that are built or licensed up front are treated as Capex, unless the period of the license is less than or equal to 12 months, in which case the expenditure is treated as Opex.

If a solution includes Capex components, the project to deliver the solution is a capital project and those components that are cloud based 'pay as you go' components are treated as Capex up until the go-live date.

- Training is always Opex
- Relocating assets is always Opex
- If something is built or licensed as Capex, it needs to remain in the ownership of UE in order to stand as Capex
- The asset must provide future economic benefit for longer than 12 months to be classified as Capex
- Trials, pilots, proofs of concept and research expenditure, for the purpose of learning or evaluating, are always Opex.

General Types of Cloud Services for deployment of software

Type of Cloud Services on which business software can be deployed	Component	Explanation
1. Business Software on Infrastructure as a Service	Deploy/License your own applications	The applications on top of this platform are Capex, because UE build or license them as assets that have future economic benefit for more than 12 months.
	Deploy/License your own platforms	The platforms on top of this cloud are Capex, because UE build or license them as assets that have future economic benefit for more than 12 months.
	Infrastructure as a Service (Cloud) (Pay as you go alternative to purchasing hardware. Eg AWS storage service)	No data centre, instead the infrastructure is provided as a service. The infrastructure as a service is Opex, but it can be capitalized as part of the above Capex project up until the go live date provided the expenditure incurred is incremental and is the result of developing/testing activities post the research phase.
2. Business Software on Platform as a Service	Deploy/License your own applications	The applications on top of this cloud are Capex, because UE build or license them as assets that have future economic benefit for more than 12 months.
	Platform as a Service (Cloud) (Pay as you go alternative to purchasing tools and technology systems. E.g. database systems or development frameworks in the cloud.)	No data centre, instead the platforming is provided as a service. The platform as a service is Opex, but it can be capitalized as part of the above Capex project up until the go live date provided the expenditure incurred is incremental and is the result of developing/testing activities post the research phase.
	Includes Infrastructure (Cloud)	No data centre, instead the infrastructure is provided as a service. The infrastructure as a service is Opex, but it can be capitalized as part of the above Capex project up until the go live date provided the expenditure incurred is incremental and is the result of developing/testing activities post the research phase.
3. Business Software as a Service	Software as a Service* (Pay as you go for applications. E.g. Procurement System, HRIS system, Gmail) *This includes the platform and infrastructure	Everything including the business application is provided as a service. The application as a service is Opex. However, it can be capitalized if it is implemented as part of a Capex project, up until the go live date, provided the expenditure incurred is for activities post the research phase. Integration with existing UE systems might be required. If so, then the project to build an integration layer, so that the cloud software can integrate with existing UE systems, could be a Capex project, provided that UE build or license an asset that has future economic benefit for more than 12 months.

1.3 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.

Fixed Asset Policy

UNITED ENERGY

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	Proposed By:	**Approved By:**
Name:	S. Edwards	D. Strang
Title:	Fixed Asset Accountant	Chief Financial Officer
Signature:	SEdwards	
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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.

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[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.

Recognition Criteria:

There are different criteria for recognising tangible and intangible assets.

Tangible:

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].

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[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.

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[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

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[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

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[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:

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[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

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[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.

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[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

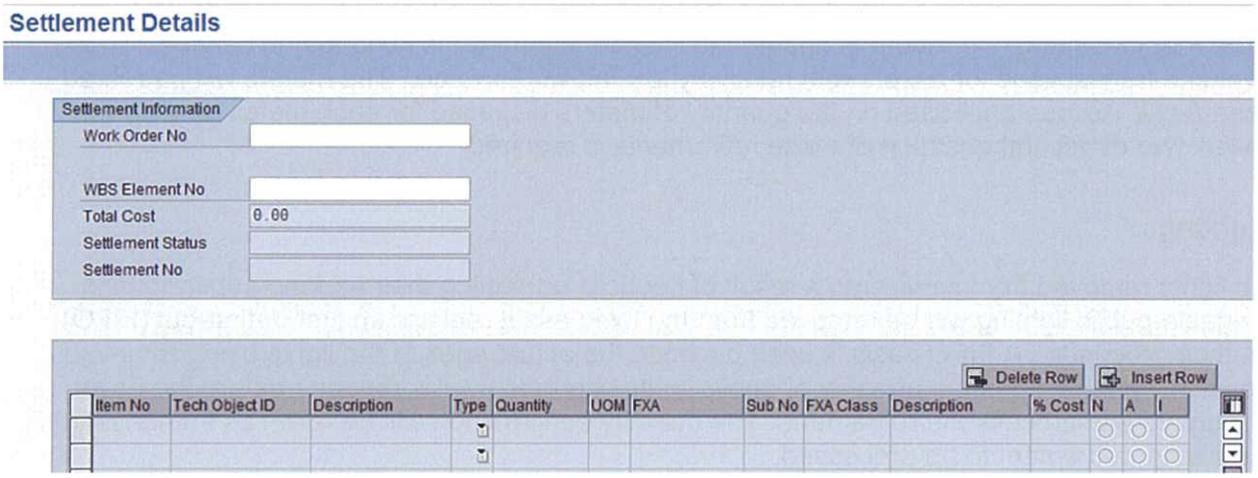
All retirements are subject to the DOA 003-POL Delegated Financial Authority Policy.

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.



Work Order No
WBS Element No
Total Cost 0.00
Settlement Status
Settlement No

Item No	Tech Object ID	Description	Type	Quantity	UOM	FXA	Sub No	FXA Class	Description	% Cost	N	A	I
											○	○	○
											○	○	○

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

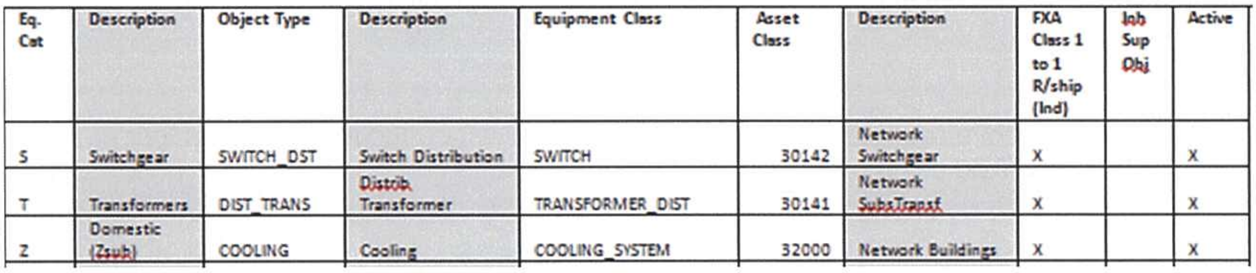
In SAP all network assets are capitalised to the SAP accounting fixed assets register. For Operational activities selected network assets are reflected in the plant maintenance equipment records. The SAP Plant Maintenance (PM) module contains hundreds of thousands of records for many, but not all, network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

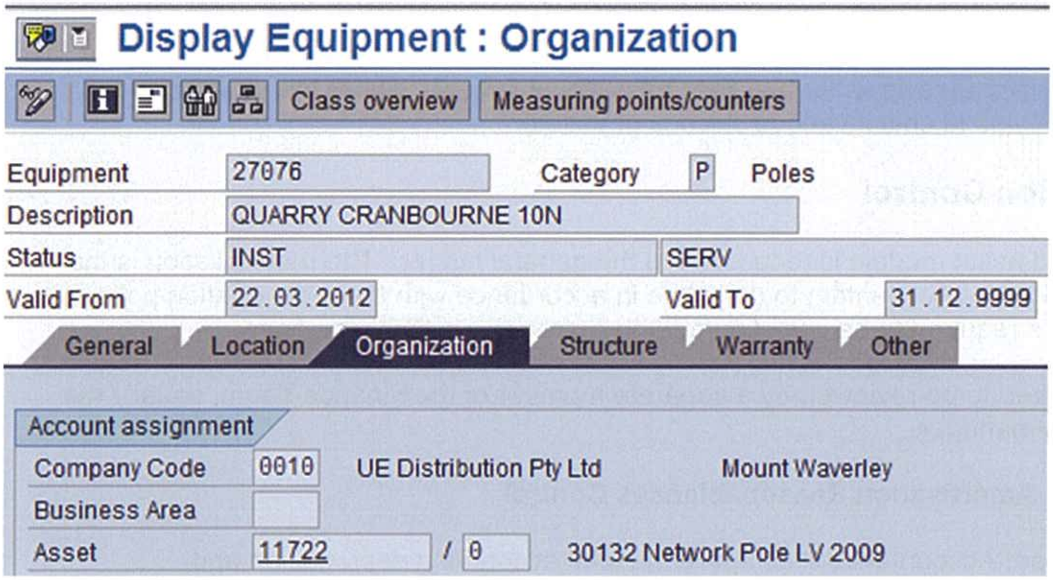
Stocktake

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.



Display Equipment : Organization

Equipment 27076 Category P Poles
Description QUARRY CRANBOURNE 10N
Status INST SERV
Valid From 22.03.2012 Valid To 31.12.9999

Account assignment
Company Code 0010 UE Distribution Pty Ltd Mount Waverley
Business Area
Asset 11722 / 0 30132 Network Pole LV 2009

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	373	372	1	0.3%	*Not applicable*

Table 2: Energy sales

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
Energy Volume	7,604	7,585	19	0.2%	*Not applicable*

Table 3: Operating and maintenance

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
Standard Control	138	142	-4	-2.8%	*Not applicable*

Table 4: Capital expenditure

	Actual ($m)	Benchmark ($m)	Difference ($m)	Percentage difference	Reason for material difference
Standard Control	209	232	-23	-10%	*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
Augmentation	19.7	34.4	-14.7	-43%	Please see table 8.2.2 in Tab 8.2
Connections	73.6	62.7	10.9	17%	
Replacement	83.0	85.3	-2.3	-3%	
Non network - IT	25.2	28.9	-3.7	-13%	
Non network - Other & SCADA	7.3	21.1	-13.8	-66%	
Standard Control - Total Additions	**208.8**	**232.4**	**-23.6**	**-10%**	

Appendix G: Explanation of material differences

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	46.76	61.19	-14.43	-24%	Targeted capital investment to reduce the individual impact on customers and the impact of targeted asset replacement
SAIFI	0.69	0.90	-0.20	-23%	
MAIFI	0.76	0.92	-0.16	-17%	

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

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
SAIDI	156.63	151.60	5.03	3%	Not Applicable
SAIFI	2.26	2.02	0.24	12%	Year on year movements of feeder classifications between urban and rural
MAIFI	3.88	2.98	0.90	30%	

Table 8: Customer service parameter – Telephone answering

	Actual	Benchmark	Difference	Percentage difference	Reason for material difference
Telephone answering	66.92%	64.78%	2.14%	3%	Not applicable

Appendix H: Demand Management Incentive Scheme Report 2016

Note: See attached

Attachments outlined on page 13 of the Demand Management Incentive Scheme Report 2015 can be provided on request.

Demand Management Incentive Scheme Report - 2016

UNITED ENERGY

DMIS Report

This report details outcomes of projects supported by the Demand Management Innovation Allowance.

TABLE OF CONTENTS

1 Introduction

During the 2016 calendar year, United Energy (UE) continued two projects under the Demand Management Incentive Scheme (DMIS). These were:

- 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 2016 and documents the outcomes and learnings of each project. Further details of each project are presented below.

1.1 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 subsequent success of this pilot during this period, we are now transitioning the pilot to business-as-usual for management of peak demand and economic deferral of traditional network augmentation. We are using part of the 2016-2020 allocation to fund this transition.

With the price of solar photovoltaic (PV) falling dramatically and the price of battery storage forecast to decrease sharply in coming 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 now 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 and where the cost of adding capacity through traditional solutions is higher than average.

The aim of the original pilot project was 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. In 2014 there was significant work completed as part of the pilot. UE successfully installed a total of thirteen VPP units distributed across our network. The installations were completed in July 2014, and significant testing, refinement and learnings have been established through the operations of these units in 2015 and 2016. The pilot project objectives were achieved in early 2016. The innovation involved in establishing the pilot project has been recognised nationally with the project recently announced as winner of the 2016 Clean Energy Council Award in the Innovation category.

Coming into 2017 we are now at a point where we want to transition this technology to business-as-usual and justify VPP on its own economic merits against traditional augmentation. With battery prices falling rapidly, we decided to retest the market for pricing of battery technology. UE commenced a competitive RFI to process in 2016 to identify any new manufacturers that could supply a full turnkey VPP solution for UE (including solar and battery technology, software and integration). The tender process found that the new Tesla Powerwall battery was at a significantly lower price point than any of the other system available on the market. To test the new product, UE set up the Burwood field depot to replicate a standard residential solar and battery installation using the Tesla Solar Storage systems in a test environment to identify the most technically suitable and least cost architecture. With this work now completed, it is planned to undertake field deployments in 2017 at identified capacity constrained sites within the UE distribution network as an alternative to traditional network augmentation.

Refer to Appendix 1 for further details on this project.

1.2 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 can be used to defer network augmentation.

The Summer Saver Trial was an investigation of how effective and efficient customer demand response is as a non-network alternative at addressing demand at peak times. The trial investigated various demand management options. The outcomes of this trial have enabled 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 for summer 2014/15 to target 4,000 more customers in areas of the network that were likely to experience an interruption from electrical asset overload. The trial also introduced new demand management options to existing trial members including direct load control of pool pumps, and supply capacity limiting.

The trial was expanded again for summer 2015/16 to target a total of 13,000 customers in areas of the network that are likely to experience an interruption from electrical asset overload. On top of the pool pump load control and supply capacity limiting options, the new option of load control of air-conditioners was added to the service offerings. A Bidgely customer smart phone application was also introduced.

The trial in 2015/16 was so successful it has been recognised as a Technology Pioneer and Best Customer Focused Technology Project by the US Peak Load Management Alliance (PLMA) and Australian Utility Innovators Awards respectively.

The success of the trial has provided UE the confidence to proceed with the Summer Saver Program[1]as a business-as-usual activity to defer traditional network augmentation using demand response. As such, Summer Saver Program will be targeted to 10,000 customers in areas of identified network constraint in summer 2016/17.

The Summer Saver Program 2017 is partially funded via DMIS as it is trialling several new elements for demand management to assist with the transition to business-as-usual and the Smart Energy smart phone application. Summer Saver Program is utilising the capabilities of the Advanced Metering Infrastructure to encourage customer participation and engagement whilst lowering implementation costs.

The majority of the costs incurred in 2016 were for the last summer of the Summer Saver Trial. This includes technology cost to support the Smart Energy app and the registration website. Other costs include marketing, participation incentives and load control technology. The remainder of the cost incurred were for Summer Saver Program 2017, which were costs for technology development and transition to business-as-usual.

Refer to Appendix 2 for further details on this project.

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[1] http://unitedenergy.com.au/summersaver

2 Regulatory Requirement and Compliance

The AER, in its Demand Management Incentive Scheme applied to UE for the 2016-2020 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 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 overnight from the network or from PV during the middle of the day when solar PV generation is at its maximum and discharging the battery during the early evening when energy demand requirements on the UE network are at their 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 sought to address specific network constraints by reducing demand on the network at the location and time of the constraint. With the VPP concept now proven by the pilot, 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 innovation involved in establishing the Sunverge pilot project has been recognised nationally with the project recently announced as winner of the 2016 Clean Energy Council Award in the Innovation category.

"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.

2.2 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 sought to incentivise customers to reduce their load during peak times. Voluntary trial customers were rewarded $5 per hour for reducing their load during the UE nominated three hour event period. Customers who reduced for all 3 hours were rewarded $25. Customers on the pool pump load control program were incentivised $40 per event for load reduction and Supply Capacity Limiting customers were incentivised $50 per event for load reduction. Customers on the air conditioner load control trial were incentivised $50 per event for load reduction and $100 as a sign up bonus.

During the period of December 2015 to March 2016, an event was called in each month totalling 4 events. Event results are summarised in Appendix 2.

"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 sought to address specific network constraints and is therefore targeted at customers directly impacted by those constraints. The trial targeted approximately 13,000 customers in areas of the network which are likely to suffer an interruption during summer or had suffered an interruption in previous summers due to electrical plant overload. Throughout the trial, UE sought to understand if sufficient numbers of customers participate in the trial with the right level of behaviour to 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."

Residential demand management as a concept is not new however trialling it in metropolitan Melbourne certainly was. 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. The innovation of the trial has been recognised locally and internationally, winning Australian Innovator Utility Awards 2016's Best Customer Engagement Project, and the US Peak Load Management Alliance's Technology Pioneer Award.

"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 Trial are costs incurred by UE in marketing the trial, creating a registration website, customer participation incentives, and procuring and installing 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.

2.3 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.

2.3.1 VPP Project

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

UE had $72,631.54 excl. GST of expenses during the 2016 calendar year on activities associated with the DMIA for VPP projects. The costs were associated with engaging external consultants, hardware procurement, installation and maintenance and ongoing operational expenses associated with the pilot.

These costs can be categorised as follows:

- $ 4.43k excl. GST for the VPP Sunverge pilot project including hardware maintenance costs, retention of operational data, ongoing operational expenses associated with the pilot (such as sim cards to enable remote control and continuous live monitoring of the systems by UE etc.) and software maintenance.
- $ 42.7k excl. GST for the Burwood Tesla pilot including procurement costs for the installation of a new inverter and reconfiguration of the Burwood installation to a dual battery architecture.
- $ 25.5k excl. GST in legal expenses.

Further costs associated with transitions of the VPP pilot project to business-as-usual are likely to be incurred by UE in the 2017 calendar year, drawn from the 2016-2020 DMIA allowance.

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 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 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 which is essentially complete consisted of a VPP system comprising thirteen installations at residential sites totalling 50kW. The installation sites were limited to UE employees and VPP project team members' premises within the UE distribution area to manage identified risks. Stage 1 was operated over an extended period to test the economics and commercial models and understand the technology's capabilities, limitations and suitability for larger scale deployment. Stage 2 which involves deployment to capacity constrained sites to defer traditional augmentation is now underway.

(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) Project. This was endorsed by the AER on the 2nd October 2013. The overall VPP project stage 1 was estimated to cost $1.75M.

Stage 2 is estimated to cost $0.2M during 2017, being largely the costs to transition the project to business-as-usual.

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

We have identified a number of constrained locations around the UE network where deployment of VPP is able to achieve peak demand reductions economically. These sites will be targeted for Stage 2.

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.

2.3.2 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 $432,821.89 excl. GST of expenses during the 2016 calendar year on activities associated with the DMIA for the Summer Saver projects comprising of the following:

- Creating a customer registration website, marketing, paying customer participation incentives, procuring and installing technology including the Smart Energy app, technology development 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 2016 was 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.

- 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.

Summer Saver Program 2017 is the transitional phase for the Summer Saver Project from a trial basis to a business-as-usual program as a non-network alternative at addressing demand at peak times. The program utilises a variation of Voluntary Demand Side Participation (DSP) similar to that of Summer Saver Trial 2016.

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

The key objectives of the Summer Saver Trial 2016 were 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 intended 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 Advanced Metering Infrastructure benefits
- develop relationships with UE customers
- explore and test contractual and commercial agreements with 3rd parties (retailers, contractors, suppliers)

The outcomes of this trial has enabled 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 is now being incorporated into business-as-usual activities to manage peak demand.

The key objectives of the Summer Saver Program 2017 is the transitioning of a trial demand response program to a business as usual activity to manage peak demand.

This includes a trial of high frequency Advanced Metering Infrastructure data to help inform customers in managing their load.

(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 investigated various demand management options that can be employed by residential customers. The results of this trial has helped 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 undertook analysis to identify areas that are likely to experience an interruption and could benefit from load reduction through demand management. Customers in these areas were sent addressed letters informing them of the project and inviting them to register via the UE registration website.

UE accepted registrations from customers within the area who have either a mobile phone or email account to receive UE event alerts.

UE sent app notifications, 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 analysed customer smart meter data to verify load reduction during the three-hour event period. Successful customers were informed via email that they will be rewarded. Rewards were processed and sent at the end of the project.

UE undertook 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 October 2014 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 Summer Saver Trial. This was endorsed by the AER on the 24th November 2014. The overall Summer Saver Trial was estimated to cost $0.59M.

In 2016 the DMIA costs were incurred on marketing activities that included letters mailed to customers and flyers dropped in letter boxes. 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. A large body of work was undertaken to create an automated registration website for customers that linked to the Smart Energy app as well as procuring and setting up the Smart Energy app. Funds were incurred on deploying DRED technology at customers' premises over the summer.

With the completion of the trial we now expect to incur further costs of approximately $0.3M during 2017, being largely the costs to transition the project to business-as-usual and for use of the Smart Energy app.

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

UE called four event days last summer.

Event data showed that:

- An average of 75% of registered customers participated at any single event. This is confirmed by post summer customer research that shows that a significant portion of customers tried to participate but data shows that they did not manage an energy reduction during the event.
- An average of 37% demand reduction was achieved across all four events
- 100% participation rate by customers on load control trials.
- No rebound peak/shifted peaks were observed during the event days

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 – VPP Pilot Project Stage 1 Report

- Background
- Virtual Power Plant Project
- Sunverge Pilot
- Tesla Pilot
- Future Initiatives

Award Links:

http://www.cleanenergysummit.com.au/awards.html

3.2 Appendix 2 - Summer Saver Project Report

- Customer Letter
- Frequently Asked Questions
- Promotional Flyer
- Terms and Conditions
- UE Website Content
- Trial Results

Award Links:

http://www.peakload.org/?page=Award2016

http://www.australian-utility-week.com//Awards

STATUTORY DECLARATION

Evidence (Miscellaneous Provisions) Act 1958, VIC

I, **Antonio Narvaez,**

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 [Insert Shortened Business Name] to make this statutory declaration as part of the response of [Insert Shortened Business Name] to the Regulatory Information Notice dated 3 February 2016 (Notice) served on **United Energy** by Business the Australian Energy Regulator (AER).

2. I say that United Energy's response to Schedule 1 of the Notice is to the best of my information, knowledge and belief in accordance with the requirements of the Notice.

3. United Energy's response to Schedule 1 of the Notice has to the best of my information, knowledge and belief:
   a) in all cases where actual information has not been provided explained why it was not possible to provide actual information and the steps **United Energy** is taking to ensure it can provide actual information in the future;

   b) where estimated information has been provided:
      i. ensured it represents **United Energy's** best estimate of the information in accordance with the requirements of the Notice; and
      ii. provided the basis for each estimate, including assumptions made and reasons why the estimate is the best estimate, given the information sought in the Notice; and
   c) in all other circumstances provided information that is true and accurate.

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 28th day of April 2017 ....

Signature of person making this declaration
[to be signed in front of an authorised witness]

Before me,

....

Signature of Authorised Witness

Niki Hantzis
an Australian legal practitioner
within the meaning of the
Legal Profession Uniform Law (Victoria)

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)

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

Opinion

We have audited the Financial Information within tables 2.11, 7.8, 7.10, 7.11, 7.13, 8.1, 8.2 and 8.4 as presented in the data template entitled "United Energy Annual RIN 2016" ("the Financial Information") of United Energy Distribution Pty Ltd ("the Company") for the regulatory year ended 31 December 2016, 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 3 February 2017, for the regulatory year ended 31 December 2016. In accordance with the requirements of the Notice, Information presented in the Financial Information before this date range has not been subject to audit. The Basis of Preparation is an appendix to the United Energy Annual RIN 2016.

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 D of the Notice, for the regulatory year ended 31 December 2016.

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 3 February 2017.

In our opinion, the Financial Information provided for the regulatory year ended 31 December 2016 is 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 materials respects, with the requirements of the Notice and the Principles and Requirements in Appendix D of the Notice.

Basis for Opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Information* section of our report. We are independent of the the Company in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants* (the Code) that are relevant to our audit of the Financial Information in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Accounting and Restriction on Distribution and Reliance

Our report is intended solely for the Directors and the Australian Energy Regulator and should not be distributed to parties other than the Directors and the Australian Energy Regulator. A party other than the Directors or the Australian Energy Regulator accessing this report does so at their own risk and Ernst & Young expressly disclaims all liability to a party other than the Directors and the Australian Energy Regulator for any costs, loss, damage, injury or other consequence which may arise directly or indirectly from their use of, or reliance on the report. Our opinion is not modified in respect of this matter.

Responsibility of the Directors for the Financial Information and Basis of Preparation

The Directors are responsible for the preparation of the Financial Information, and have determined that the definition of Financial Information, as presented within tables 2.11, 7.8, 7.10, 7.11, 7.13, 8.1, 8.2, 8.3, and 9.5 of the data template entitled "United Energy Annual RIN 2016" is appropriate to the needs of financial users. This responsibility includes such internal control that the Directors determine is necessary to enable the preparation of the Financial Information that is free from material misstatement, whether due to fraud or error.

The Directors are also responsible for the preparation of the Basis of Preparation consistent with the requirements of the Notice and the Principles and Requirements in Appendix D of the Notice.

Auditor's Responsibility for the Audit of the Financial Information

Our objectives are to obtain reasonable assurance about whether the Financial Information is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this Financial Information.

As part of an audit in accordance with Australian Auditing Standards, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Financial Information whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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 control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates, if any, and related disclosures made by the directors.

Our objectives are also to express a conclusion on compliance, in all material respects, of the Basis of Preparation with the requirements of the Notice and the Principles and Requirements in Appendix D of the Notice.

We communicate with the Directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young

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Melbourne
26 April 2017

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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 reviewed the Non-financial information within tables 3.6, 3.6.8, 3.6.9, 6.2, 6.6, 6.7 and 6.9 in the data template entitled "United Energy Annual RIN 2016" (the "Non-Financial Information") attached, which has been prepared by United Energy Distribution Pty Ltd in response to the Annual Regulatory Information Notice ("the Notice") issued by the Australian Energy Regulator on 3 February 2017, for the regulatory year ended 31 December 2016.

This information has been prepared in accordance with United Energy Distribution Pty Ltd's Basis of Preparation (the "Basis of Preparation") in response to the Notice issued by the Australian Energy Regulator on 3 February 2017, for the regulatory year ended 31 December 2016. In accordance with the requirements of the Notice, information presented in the Non-Financial Information before this date range has not been subject to review.

In addition, we have reviewed 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 D of the Notice, for the regulatory year ended 31 December 2016.

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 3 February 2017.

Directors' Responsibility for the Non-Financial Information and Basis of Preparation

The directors are responsible for the preparation of the Non-Financial Information and the Basis of Preparation, and have determined that the Basis of Preparation used is appropriate to the needs of the Australian Energy Regulator. The directors are also responsible for such internal controls as the directors determine 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 a conclusion on the Non-Financial Information based on our review.

We have conducted our review of the Non-Financial Information in accordance with the Australian Standard on Assurance Engagements ASAE 3000 *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* in order to state whether, on the basis of the procedures described, anything has come to our attention that causes us to believe that the Non-Financial Information is not prepared, in all material respects, in accordance with the Basis of Preparation and the requirements of the Notice.

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 Non - Financial Information. Our review has been conducted in accordance with the Australian Standard on Assurance Engagements ASAE 3100 *Compliance Engagements* to provide limited assurance. These procedures have been undertaken to form a conclusion that nothing has come to our attention that causes us to believe that the Basis of Preparation has not complied, in all material respects, with the Notice.

ASAE 3000 and ASAE 3100 require us to comply with the requirements of the applicable code of professional conduct of a professional accounting body.

A review consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Independence

In conducting our audit we have met the independence requirements of the Australian professional accounting bodies.

Conclusion

Based on our review, which is not an audit, nothing has come to our attention that causes us to believe that the Non-Financial Information is not prepared, in all material respects, in accordance with the requirements of the Notice or United Energy Distribution Pty Ltd's Basis of Preparation. In addition, nothing has come to our attention that causes us to believe that the Basis of Preparation does not comply, in all material respects, with the Notice.

Basis of Accounting and Restriction on Distribution

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 parties other than United Energy Distribution Pty Ltd or the Australian Energy Regulator.

A party other than the Directors or the Australian Energy Regulator accessing this report does so at their own risk and Ernst & Young expressly disclaims all liability to a party other than the Directors and the Australian Energy Regulator for any costs, loss, damage, injury or other consequence which may arise directly or indirectly from their use of, or reliance on the report. Our conclusion is not modified in respect of this matter.

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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

Opinion

We have audited the financial report, being a special purpose financial report, of United Energy Distribution Pty Ltd ("the Licensee"), which comprises the statement of financial position as at 31 December 2016, income statement, statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, notes to the financial statements, including a summary of significant accounting policies, and the directors' declaration.

In our opinion, the accompanying financial report is prepared, in all material respects, in accordance with the accounting policies described in Note 1 to the financial statements and the Regulatory Accounting Information Requirements of the Australian Energy Regulator.

Basis for Opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Report* section of our report. We are independent of the Licensee in accordance with the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Accounting and Restriction on Distribution and Reliance

We draw attention to Note 1 to the financial statements which describes the basis of accounting. The financial report is prepared to assist the Licensee to meet the requirements of the United Energy Distribution Pty Ltd Regulatory Information Notice issued by the Australian Energy Regulator. As a result the financial report may not be suitable for another purpose. Our report is intended solely for the Licensee and the Australian Energy Regulator (collectively the Recipients) and should not be distributed to parties other than the Recipients.

A party other than the Recipients accessing this report does so at their own risk and Ernst & Young expressly disclaims all liability to a party other than the Recipients for any costs, loss, damage, injury or other consequence which may arise directly or indirectly from their use of, or reliance on the report. Our opinion is not modified in respect of this matter.

Responsibilities of the Directors for the Financial Report

The directors of the Licensee are responsible for the preparation of the financial report in accordance with the financial reporting requirements of the Regulatory Accounting Information Requirements of the Australian Energy Regulator and for such internal control as the partners determine is necessary to enable the preparation of the financial report that is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the Licensee's ability to continue as a going concern, disclosing, as applicable, matters relating to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Licensee or to cease operations, or have no realistic alternative but to do so.

Auditor's Responsibilities for the Audit of the Financial Report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit 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 Licensee's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.

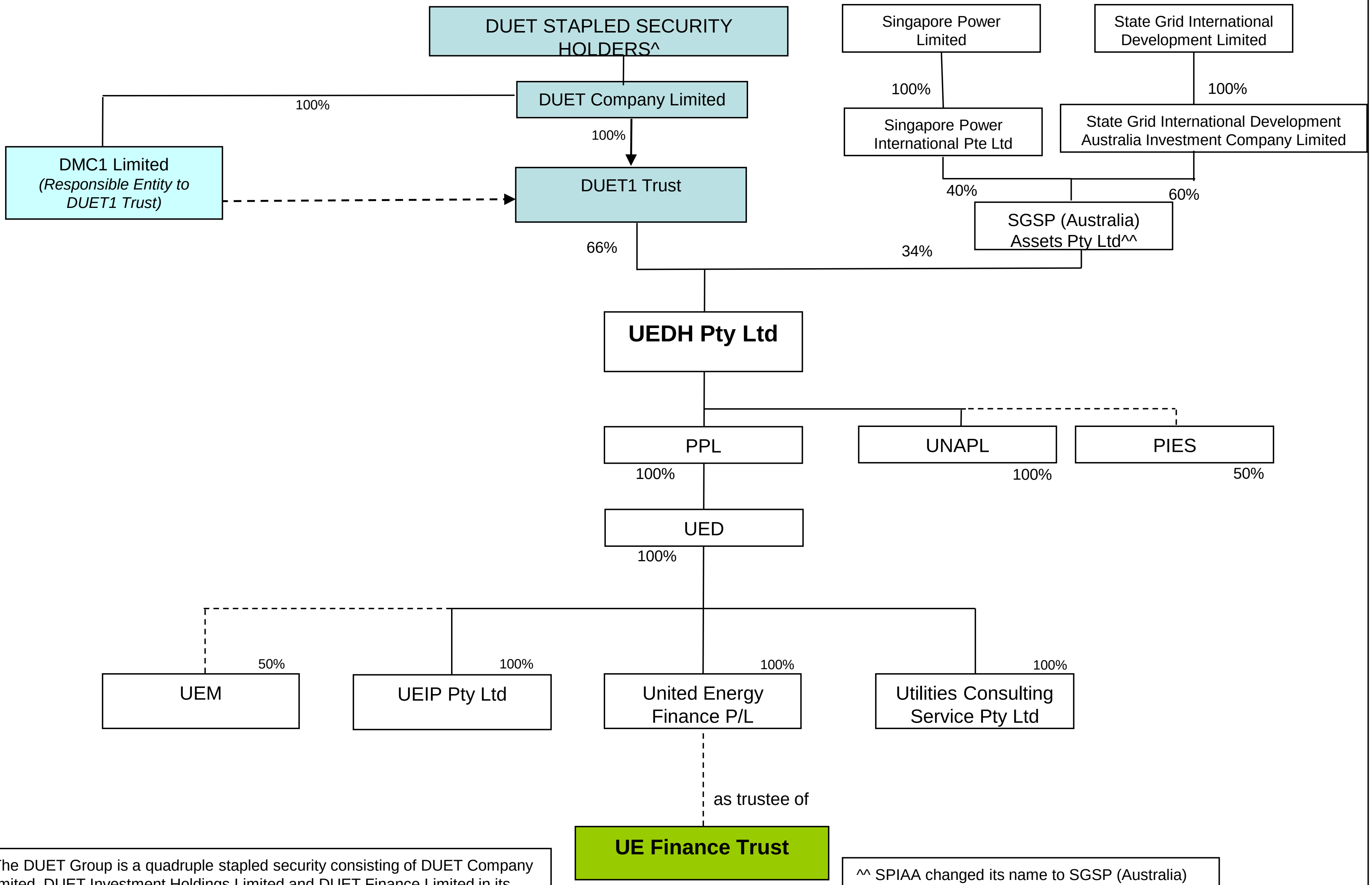
- Conclude on the appropriateness of the directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Licensee's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Licensee to cease to continue as a going concern.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young

Ernst & Young
Melbourne
26 April 2017

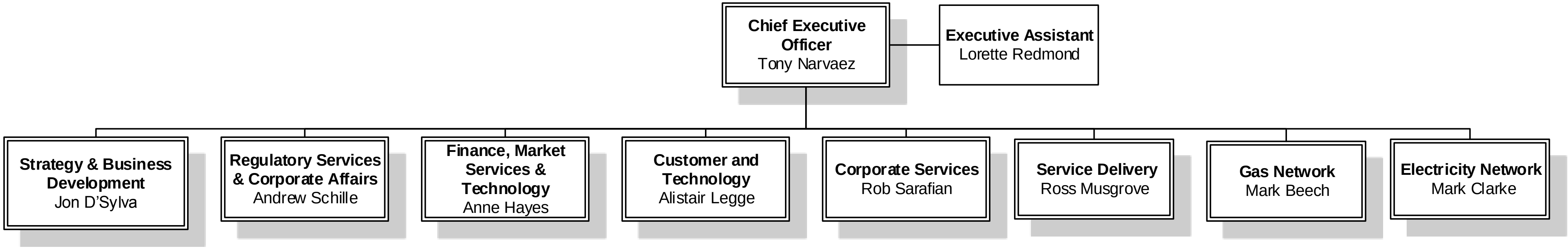
UEDH Corporate Structure Diagram



^The DUET Group is a quadruple stapled security consisting of DUET Company Limited, DUET Investment Holdings Limited and DUET Finance Limited in its personal capacity and as responsible entity of DUET Finance Trust.

^^ SPIAA changed its name to SGSP (Australia) Assets Pty Limited on 3rd January 2014.

April 2015



Chief Executive Officer
Tony Narvaez

Executive Assistant
Lorette Redmond

Strategy & Business Development
Jon D'Sylva

Regulatory Services & Corporate Affairs
Andrew Schille

Finance, Market Services & Technology
Anne Hayes

Customer and Technology
Alistair Legge

Corporate Services
Rob Sarafian

Service Delivery
Ross Musgrove

Gas Network
Mark Beech

Electricity Network
Mark Clarke

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	0	225	225	0%	100%