Regulatory Information Notice Response

Regulatory Year One

1 July 2012 to 30 June 2013

As Submitted to the AER

CONTACT

This document is the responsibility of the Commercial, Regulatory and Strategy Group within the Distribution Business of Aurora Energy Pty Ltd (ABN 85 082 464 622). Please contact the indicated owner of the document with any queries or suggestions.

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Introduction

This document (RIN Response) represents the response of Aurora Energy (ABN 85 082 464 622) to the Regulatory Information Notice (RIN) issued by the Australian Energy Regulator (AER) on 28 September 2012 under Division 4 of Part 3 of the *National Electricity (Tasmania) Law*. The information and explanatory material included in this RIN Response relate to Aurora's activities as a licensed Distribution Network Service Provider during the 2012-13 Regulatory Year.

Definitions and interpretation

In this document, unless otherwise noted:

'**Aurora**' refers to Aurora Energy, acting in its capacity as a licensed Distribution Network Service Provider in the Tasmanian jurisdiction of the National Electricity Market.

'**2012-17 Distribution Determination**' refers to the distribution determination made by the Australian Energy Regulator that applies to Aurora Energy for the five year regulatory control period that commenced on 1 July 2012 and concludes on 30 June 2017.

'**Relevant Regulatory Year**' refers to the regulatory year for which Aurora is required to complete the Regulatory Information Notice issued by the AER, being the 2012-13 Regulatory Year.

Abbreviations	
AER	Australian Energy Regulator
Aurora	Aurora Energy Pty Ltd
CAM	Cost Allocation Method
DUoS	Distribution Use of System
ICAM	Indirect Cost Allocation Model
MAIFI	Momentary Average Interruption Frequency Index
OTTER	Office of the Tasmanian Electricity Regulator
POW	Program of Work
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
Transend	Transend Networks Pty Ltd
TUoS	Transmission Use of System
WASP	Aurora's program-of-work management system, WASP (Works, Assets, Solutions and People)

Statutory Declaration

Statutory Declaration

I, PETER LEIGH DAVIS
MANAGING DIRECTOR / CHIEF EXECUTIVE OFFICER
Confidential

....

do solemnly and sincerely declare that:

1. I am an officer, for the purposes of the *National Electricity (Tasmania) Law* (NEL), of Aurora Energy (ABN 85 082 464 622), a company established under the *Electricity Companies Act 1997* (Tas) (Aurora Energy).

2. Aurora Energy is a regulated network service provider that provides electricity distribution network services in Tasmania in accordance with the purposes of section 28D of the NEL.

3. The response of Aurora Energy regarding the information required to be provided and to be prepared and maintained as specified by the Australian Energy Regulator's (AER) Regulatory Information Notice (Notice) dated 28 September 2012, with the exception of the information specified to be audited under paragraph 1.1 of Appendix E to the Notice, is to the best of my information, knowledge and belief:

   (a) in accordance with the requirements of the Notice; and

   (b) true and accurate

   in respect of the distribution services provided by way of the electricity distribution network Aurora Energy operates in Tasmania.

I make this solemn declaration under the *Oaths Act 2001*.

Declared at HOBART
(Place)

on 27 NOVEMBER 2013
(Date)

Signature

Before me, JANELLE MARIE O'REILLY
SOLICITOR ADMITTED TO PRACTISE IN VIC NSW & TAS
OF Confidential
(Justice, commissioner for declarations or authorised person)

Confidentiality

Confidentiality Claims

Document	Description	Topic	Category	Explanation	Detriment from disclosure	Detriment v public benefit
Title, page and paragraph number of document containing confidential information	*Description of the confidential information*	*Topic the confidential information relates to (e.g. capex, opex, WACC)*	*Confidentiality category*	*Explanation of categorisation*	*Detriment to Aurora associated with disclosure of the identified information*	*Information supporting why the identified detriment outweighs the public benefit of publication*
Regulatory Information Notice Response, Regulatory Year One, 1 July 2012 to 30 June 2013. Page 7. First paragraph.	Home address of Aurora Chief Executive Officer.	Statutory Declaration. True and accurate certification for RIN response (in accordance with RIN Appendix D).	Personal information.	Release of Aurora Chief Executive Officer's home address raises material privacy issues – inconsistent with the National Privacy Principles.	Breach of the personal privacy of the Aurora Chief Executive Officer.	There is no public benefit from the publication of the home address of the Aurora Chief Executive Officer. Home address provided to ensure a compliant Statutory Declaration in accordance with the *Oaths Act 2001*.
Regulatory Information Notice Response, Regulatory Year One, 1 July 2012 to 30 June 2013. Page 7. Final paragraph.	Home address of Aurora Company Secretary.	Statutory Declaration. True and accurate certification for RIN response (in accordance with RIN Appendix D).	Personal information.	Release of Aurora Company Secretary's home address raises material privacy issues – inconsistent with the National Privacy Principles.	Breach of the personal privacy of the Aurora Company Secretary.	There is no public benefit from the publication of the home address of the Aurora Company Secretary. Home address provided to ensure a compliant Statutory Declaration in accordance with the *Oaths Act 2001*.
Regulatory Information Notice Response, Regulatory Year One, 1 July 2012 to 30 June 2013. Page 100. First paragraph.	Home address of Aurora Chairman.	Statutory Declaration to support response to Section 12 of Schedule 1 (Board approval of RIN response).	Personal information.	Release of Aurora Chairman's home address raises material privacy issues – inconsistent with the National Privacy Principles.	Breach of the personal privacy of the Aurora Chairman.	There is no public benefit from the publication of the home address of the Aurora Chairman. Home address provided to ensure a compliant Statutory Declaration in accordance with the *Oaths Act 2001*.
Regulatory Information Notice Response, Regulatory Year One, 1 July 2012 to 30 June 2013. Page 100. Final paragraph.	Home address of Aurora Company Secretary.	Statutory Declaration to support response to section 12 of Schedule 1 (Board approval of RIN response).	Personal information.	Release of Aurora Company Secretary's home address raises material privacy issues – inconsistent with the National Privacy Principles.	Breach of the personal privacy of the Aurora Company Secretary.	There is no public benefit from the publication of the home address of the Aurora Company Secretary. Home address provided to ensure a compliant Statutory Declaration in accordance with the *Oaths Act 2001*.

Aurora is required to specify the number of pages in its submission that contain information which is subject to a claim of confidentiality.

Proportion of confidential material					
Submission Title	**Pages with confidential content**	**Pages with no confidential content**	**Total pages**	**Percentage of pages with confidential content**	**Percentage of pages with no confidential content**
Regulatory Information Notice Response Regulatory Year One 1 July 2012 to 30 June 2013	2	114	116	2%	98%

Note: This is an approximate indication of the proportion of material in Aurora's response to the AER's RIN for the 2012-13 regulatory year which is subject to a claim of confidentiality.

January 2013 Tasman Peninsula Bushfires

In early January 2013, bushfires in Tasmania's lower South-east, including the Tasman and Forestier Peninsula, caused significant damage to Aurora infrastructure, resulting in a number of sustained outages. More than 7,000 customers were affected and about 2,500 customers were without power for two weeks while the network was rebuilt.

At a state-wide level, the first day of the south-east Tasmanian bushfire event on 4 January 2013 would have added 0.03 interruptions and 147 minutes to Aurora's Third Party SAIFI and SAIDI measures respectively. The bushfire was, however, excluded from assessments of the performance of the distribution network and for the purposes of the AER's Service Target Performance Incentive Scheme.

In rebuilding the network on the Tasman and Forestier Peninsulas, Aurora replaced approximately 100 km of overhead lines (both low and high voltage), 89 transformers, 772 poles and 11 overhead switching/switchgear devices, at a total cost of $7.3 million. These figures do not include the replacement of assets lost as a result of other bushfires around the State during 2012-13.

Aurora employees from throughout Tasmania were applied to the recovery effort, with Aurora's own field crews supplemented by about 50 interstate contractors sourced from SP Ausnet, Zinfra and Lend Lease. At the operation's peak, as many as 250 Aurora employees and contractors were working on the restoration of power to the Tasman Peninsula.

In addition to the expenditure associated with the restoration of services in areas affected by the bushfires, Aurora Energy also provided a $1.3 million package of emergency relief measures to help customers across Tasmania who were affected by the bushfires. The assistance measures were aimed at helping customers whose properties had been destroyed by the fires, as well as customers whose properties had survived but were experiencing extended electricity outages.

Residential and business customers whose properties were destroyed received debt waivers, Guaranteed Service Level (GSL) payments and discounts on the cost of new electricity connections associated with the rebuilding of their properties. Customers who lost electricity supply for an extended period in bushfire impacted areas and were eligible for a GSL payment also received an automatic credit of $100 on their electricity account to offset any fixed daily charges.

While many of the emergency relief measures were funded by Aurora's Energy Business, it was Aurora's Distribution Business which met the cost of the GSL payment of $160 per affected customer. As at 30 June 2013, nearly 3,900 GSL payments had been made as a direct result of the bushfires, at a cost to Aurora of $622,000.

Mobile generation support, in the form of two 1.5 Megawatt mobile generation units sourced from Ergon Energy in Queensland, was also used to restore local supplies of energy to customers as the network in bushfire affected areas was progressively reconstructed. When mobile generator hire and freight are added to the cost of the bushfire-related GSL payments, as well as labour costs (both internal and subcontractor), Aurora incurred additional operational expenditure of $1.9 million in 2012-13 as a direct result of the bushfires on the Tasman Peninsula.

The redirection of resources to the bushfire recovery also impacted on the delivery of other components of Aurora's program of work, such as vegetation management.

Section 1 - Provide information

For the 2012-13 Regulatory Year, Aurora is required to submit to the AER detailed financial and operational information relating to the distribution services provided by Aurora by way of its electricity distribution network in Tasmania. That information is required to be prepared, provided and maintained in the form specified in the Regulatory Information Notice issued by the AER.

Paragraph 1.1(a) - Regulatory Accounting Statements

Aurora is required to submit to the AER detailed capital, operating and maintenance expenditure information relating to the provision of standard control services, alternative control services, negotiated distribution services and unregulated distribution services for the 2012-13 Regulatory Year. Aurora has provided that information using the Microsoft Excel Workbook attached to the AER's RIN at Appendix B.

Attachment: ***Aurora Energy RIN Response (2012-13) – Regulatory Accounting Statements.xls***

Paragraph 1.1(b) - Non-financial regulatory information

Aurora is required to submit to the AER detailed non-financial information relating to the provision of distribution services and the performance of its electricity distribution network for the 2012-13 Regulatory Year. Aurora has provided that information using the Microsoft Excel Workbook attached to the AER's RIN at Appendix C.

Attachment: ***Aurora Energy RIN Response (2012-13) – Non-Financial Regulatory Templates.xls***

Paragraph 1.1(c) - Regulatory Accounting Statements explanatory information

In addition to the regulatory accounting information submitted in response to paragraph 1.1(a) of the AER's RIN for the 2012-13 Regulatory Year, Aurora is required to provide, where applicable, explanations of the assumptions and methodologies underlying the regulatory accounting statements provided, as well as details of any instances where the requested information was not able to be provided, or could not be provided in full.

Aurora confirms that it has allocated its Corporate and Shared Services costs to the Distribution Business in accordance with Aurora's approved ICAM and that the Distribution Business costs have been allocated to the service segments in accordance with the AER approved Cost Allocation Method.

There are a number of instances where costs incurred within the Aurora business have not been allocated to the Distribution Business and are held by Aurora at the consolidated level. In these instances Aurora has not provided any information and has noted this with an explanation of 'not allocated'.

Aurora has utilised the following methodologies to escalate the expenditure forecasts provided by the AER as part of the 2012-17 Distribution Determination:

- for instances where the AER had provided forecasts in 2009-10 dollars, Aurora has escalated by the difference between the December 2009 and March 2012 CPI indices; and

- for instances where the AER had provided forecasts in 2011-12 dollars, Aurora has escalated by the difference between the March 2011 and March 2012 CPI indices.

The following table details the assumptions and methodologies underlying Aurora's Regulatory Accounting Statements for the 2012-13 Regulatory Year, as well as any instances where the requested information has not been provided, or has not been provided in full.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Template 1 - Income Statement		
Distribution revenue	• Revenue received in respect to DUoS, Metering, Public Lighting, Fee Based Services and Quoted Services.	
TUOS revenue	• Revenue received in respect to the TUoS charges contained within Aurora's approved network tariffs.	

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Cross boundary revenue		• Not applicable to Aurora.
Profit from sale of fixed assets	• Proceeds from sale of motor vehicle fleet.	
Customer contributions	• Revenue received from the application of Aurora's customer capital contributions policy.	
Other revenue	• Unregulated revenue received in respect to metering services, Telco, Pay As You Go prepaid electricity services, street lighting and external contracting sales.	
TUOS costs	• Transmission charges received from Transend for connection to the transmission network.	
Cross boundary charges		• Not applicable to Aurora.
Maintenance	• Routine and non-routine asset maintenance and repairs, emergency response and vegetation management.	
Operating expenses	• Costs associated with network management, regulatory compliance, customer service, corporate and shared services, GSL payments, NEM costs and the electrical safety levy.	
Depreciation	• Based on Distribution roll forward regulated asset base with additions and disposals recorded during 2012-13.	
Finance charges		• Not allocated.
Loss from sale of fixed assets	• Losses recorded on the sale/disposal of fixed assets.	

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Impairment losses (Nature:)	• Reflects the revaluation of meters undertaken at the commencement of Aurora's 2012-17 Distribution Determination.	
Profit before tax (PBT)	• The financial losses shown in relation to Alternative Control Services reflect the impact of depreciation associated with shared services assets which have been apportioned to alternative control services. The apportionment is an outcome of the shared services split undertaken by the AER at the start of the regulatory control period in order to set the standard control RAB for the purposes of calculating Aurora's allowable revenue for the regulatory control period. The shared asset split includes the asset class of overhead high voltage lines rural, which has historically been used by Aurora to capture costs relating to shared services but has been classified by the AER as relating to the provision of quoted services.	

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Template 2 - Balance Sheet		
Current assets		
Cash and cash equivalents		• Not allocated.
Trade and other receivables	• Based on the Distribution Business sundry debtors as at 30 June 2013, apportioned by service segment as a percentage of total sundry debtors. • Irrecoverable receivables are impaired in the current period as an expense.	
Financial assets		• Not allocated.
Derivatives		• Not allocated.
Current tax assets		• Not allocated.
Prepayments		• Not allocated.
Accrued revenue		• Not allocated.
Inventories	• Based on the Distribution Business asset base as at 30 June 2013.	
Investments		• Not allocated.
Other	• Based on the Distribution Business asset base as at 30 June 2013.	
Non-current assets		
Receivables		• All irrecoverable receivables that are impaired are expensed in the current period.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Financial assets		• Not allocated.
Derivatives		• Not allocated.
Deferred tax asset		• Not allocated.
Property, plant and equipment	• Based on the Distribution Business asset base as at 30 June 2013.	
Investments		• Not allocated.
Other	• Based on the Distribution Business asset base as at 30 June 2013.	
Current liabilities		
Trade and other creditors	• Based on the Distribution Business total expenditure as at 30 June 2013.	
Interest bearing borrowings	• Based on the Distribution Business asset base as at 30 June 2013, as borrowings are used to fund the non-operating cash flow component of the asset base.	
Customer deposits		• Not allocated.
Bank overdraft		• Not allocated.
Current tax liability		• Not allocated.
Provisions	• Based on the Distribution Business current provisions including its retirement benefit obligations as at 30 June 2013.	
Other	• Based on the Distribution Business asset base as at 30 June 2013.	

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Non-current liabilities		
Provisions	• Based on the Distribution Business non-current provisions as at 30 June 2013 including the retirement benefit obligation.	
Interest bearing borrowings	• Based on the Distribution Business asset base as at 30 June 2013 as borrowings are used to fund the non-operating cash flow component of the asset base.	
Retirement benefit obligations		• Not allocated.
Deferred tax liability		• Not allocated.
Deposits		• Not allocated.
Other	• Based on the Distribution Business asset base as at 30 June 2013.	
Contributed Equity		• Not allocated.
Reserves		• Not allocated.
Retained Profits		• Not allocated.
Outside equity interests		• Aurora's Distribution Business does not have equity contributed by outside interests.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies	Paragraph 1.1(c)(ii) Information not provided or not provided in full
Template 5 - Capex		
Standard control services by reason		
Forecasts	• Forecasts have been sourced from the AER's capex model and escalated by the difference between the December 2009 and March 2012 CPI indices.	
Capex by asset class		
Forecasts	• Forecasts have been sourced from the AER's PTRM and escalated by the difference between the March 2011 and March 2012 CPI indices.	

As a result of the differing escalation factors used by Aurora the totals within Table 1 – Standard control services by Reason and Table 3 – Capex by Asset Class do not reconcile.

Paragraph 1.1(c) - Non-Financial Regulatory Templates explanatory information

In addition to the non-financial information submitted in response to paragraph 1.1(b) of the AER's RIN for the 2012-13 Regulatory Year, Aurora is required to provide, where applicable, explanations of the assumptions and methodologies underlying the non-financial information provided, as well as details of any instances where Aurora has either not been able to supply the requested information, or could not provided the information in full.

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 1a – STPIS Reliability		
Unplanned SAIDI	• Calculated as the sum of the kVA duration for each supply reliability category divided by the currently connected kVA of the category (i.e. the kVA approach). • Aurora's unplanned SAIDI calculation methodology differs from the RIN unplanned SAIDI definition (RIN page 15).	
Unplanned SAIFI	• Calculated as the sum of kVA interrupted for each supply reliability category divided by the current connected kVA of the category (the kVA approach). • Aurora's unplanned SAIFI calculation methodology differs from the RIN's unplanned SAIFI definition (RIN page 16).	
MAIFI	• The MAIFI calculation for the supply reliability categories includes the sum of the kVA interrupted on feeders (based on data provided by Transend) and Aurora reclosers.	• Momentary interruptions are not recorded for all feeders. • Aurora is unable to determine causes of MAIFI and, therefore, can only exclude momentary interruptions on Major Event Days.

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full

Average distribution customers	• Total distribution customer numbers count the number of connected NMIs which are not extinct.
	• Customer numbers at the start of period are determined by filtering NMIs where:
	  • the 'active' date is prior to the start date of the period; and
	  • the 'archived' date is 'null' or after the start date of the period.	

Template 1c – STPIS Daily Performance		
Total system performance (SAIDI and SAIFI)	• The sum of total system kVA duration or kVA interrupted by day, divided by the currently connected kVA of the system.	
Supply reliability category performance (SAIDI and SAIFI)	• The sum of total category kVA duration or kVA interrupted by day, divided by the currently connected kVA of the supply reliability category.	
MAIFI	• The sum of total kVA interrupted due to momentary interruptions, divided by the currently connected kVA of the system.	• Momentary interruptions are not recorded for all feeders.

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 1d – STPIS MED Threshold		
Total unplanned customer minutes off supply (after removing excluded events allowed under clause 3.3a of the STPIS)	• Unplanned customer minutes off supply is based on kVA durations, not customer minutes (in accordance with Aurora's STPIS reporting).	
Template 1e – STPIS Exclusions		
Outages by day	The following outage causes are excluded: • Bushfires, customer installation faults, house fires, planned outages, transmission outages, total fire bans.	• Aurora is unable to provide MAIFI data at the outage cause level.
Template 2 – Demand		
90% probability of exceedence		• The 2012 Aurora demand forecast did not include network level maximum coincident demand forecasts at the 90% PoE level.
Howrah sub-station forecasts		• In previous demand forecasts the load for the Howrah substation has been attributed to other substations. • Forecasts for the Howrah substation will commence during 2013/14.

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 3 – Customer Service and Quality of Service		
Over voltage events	• High voltage injection events relate to reported incidents involving HV/LV contact and transmission over voltage events. • The number of customers receiving over voltage, due to high voltage injection, is based on the number of claims made by customers for damaged equipment relating to those events. • Over voltage events due to lightning relates to the number of reported interruptions where the reported cause was lightning. • The number of customers receiving over voltage events due to lightning is taken from the number of claims made by customers for damaged equipment relating to those events. • Over voltage events (and the number of customers receiving over voltage events) due to voltage regulation or other causes are taken from the number of complaints attended where a recording of the supply voltage verified the over voltage situation. • The number of customer complaints is the best measure available to Aurora to determine whether customer(s) have been impacted by an over voltage event.	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Voltage variations		• Voltage variation information is not currently collected at the levels requested. • Aurora has a proposed project which will install Power Quality meters to allow the collection and reporting of voltage variation data at the requested levels. • It is anticipated that this data will be collected and supplied for 2014/15.
Timely repair of faulty streetlights	**Total streetlight numbers** • Total streetlight numbers were extracted on 21 October 2013. • The Aurora GIS is constrained in its ability to extract data and generate reports retrospectively, therefore the total number of streetlights may be slightly overstated.	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 4 – General Information		
Number of metered supply points	• The reported numbers of metered supply points in Tasmania are based on a stock-take of the registered NMIs recorded in Aurora's Gentrack system. **By type of customer** • The network tariff applying to each NMI has been identified on the basis of billing data extracted from the network billing system. • NMIs are allocated to customer categories based on the network tariff applying to each connection point. **By supply voltage** • HV/LV customers are identified as metered supply points on high voltage or low voltage network tariffs.	
Energy delivered (GWh)	**By type of customer** • Network tariffs (domestic or non-domestic) have been used as the basis for determining energy delivered by type of customer. **By supply voltage** • HV/LV customers are identified as metered supply points on high voltage or low voltage network tariffs.	
Line length	• Overhead LV includes: LV spans, LV service spans and LV services. • Subtransmission length: Conductor/cable links to feeder category is used to determine if a line is subtransmission.	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Customer numbers	• Customers numbers are assumed to equal total NMIs. • The total number of customers at the end of the period is calculated as: o Total number of customers at end of previous period (30 June 2012); *plus* o New customer connections (i.e. the number of new connections during the period 1 July 2012 to 30 June 2013, based on the number of new NMIs issued); *less* o Disconnected customers (i.e. the number of disconnections from 1 July 2012 to 30 June 2013, based on the number of connection points abolished, which is indicated by an NMI becoming extinct). • The apportionment between supply voltage types is based on the connected tariff applying to each customer, which is obtained from Distribution Business billing data.	
Number of unmetered supply points	• Unmetered supply points have been apportioned between supply reliability categories based on density.	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
FTE employees	The number of Distribution Business FTE employees is exclusive of non-Aurora employees (contractors). The number of FTE employees is: 1. Allocated between Network and Network Services based on department (cost centre); then 2. Split between the service segments on the following basis: • **Directly allocated –** FTEs working exclusively on one service type have been fully allocated to that service (e.g. Unregulated NBN/Telco). • **Network Services –** FTEs have been allocated between the service segments based on the volume of labour hours allocated to the provision of each type of service. • **Network –** FTEs have been allocated between the service segments based on total spend of direct and other overheads .	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 5a – Network Data - Outages		
kVA minutes off supply	• The kVA duration and customer minutes fields cannot always be calculated based on the source data, as kVA duration will not always be the product of kVA interrupted multiplied by the total outage duration (minutes). • This is due to some outages having progressive restorations, meaning that the network is switched around to restore power to some customers while others remain isolated and left off for longer. • However, the outage duration is measured from when the first customer loses power until the last customer is restored. • The kVA duration of each outage is the sum of the kVA of each transformer affected by the outage, multiplied by the minutes that each transformer was off.	
Number of customers interrupted	• The number of customers interrupted has been derived at a community level, rather than a feeder level, and reflects the 101 geographical areas used to establish reliability standards.	
kVA minutes off supply	• As per unplanned outages (above)	
Number of customers interrupted	• As per unplanned outages (above)	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 5b – Feeder Reliability		
Supply reliability area		• Feeders frequently supply multiple supply reliability areas, which makes it impossible to attribute a single supply reliability category to each feeder. • The supply reliability area field has not, therefore, been populated.
Supply reliability category		• While each supply reliability area has an associated reliability category, feeders are not always exclusive to the one community or the one reliability category. • While Aurora's GIS attributes a feeder category to each feeder, the categories do not align with the reliability categories defined in the Distribution Network Reliability Standards set out in the Tasmanian Electricity Code, and for this reason – as well as the fact that a single feeder can service multiple areas and reliability categories – the supply reliability category field has not been populated.

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Energy not supplied (unplanned) (MWh)	• Energy not supplied is the product of kVA interrupted multiplied by the time the kVA was disconnected. • This figure is calculated automatically in our outage reporting system hence no manual calculation was necessary. • The automatic calculation takes into account the outage duration for each feeder segment affected by a given outage. • This calculation is also used in the STPIS that applies for Aurora's current regulatory control period.	• As agreed with the AER, Aurora uses kVA connected as a proxy for customer numbers as, historically, Aurora has not been able to provide reliable customer data.
Total number of unplanned outages	• The total number of unplanned outages for each feeder reflects the number of unplanned outages affecting each feeder during the regulatory year, as well as outages attributed to third parties.	
Unplanned customer minutes off-supply (including excluded events and MEDs)	• Unplanned customer minutes off-supply is based on kVA minutes, not customer minutes, as agreed by the AER as part of the Aurora Distribution Determination.	
Unplanned customer minutes off-supply (after removing excluded events and MEDs)	• Unplanned customer minutes off-supply is based on kVA minutes, not customer minutes, as agreed by the AER as part of the Aurora Distribution Determination.	
Unplanned interruptions (SAIFI)	• SAIFI has been calculated on the basis of kVA interrupted, rather than the number of customers interrupted, as agreed with the AER as part of the Aurora Distribution Determination.	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Momentary interruptions due to feeder outages (MAIFI)	• MAIFI has been calculated on the basis of kVA interrupted, rather than the number of customers interrupted, as agreed with the AER as part of the Aurora Distribution Determination.	• Aurora has only been able to provide MAIFIs for 66% of the feeders which supply Aurora's distribution network. • While Aurora receives MAIFIs from Transend Networks in relation to feeders that originate at terminal substations owned and operated by Transend, Aurora currently has no systems in place to warehouse the interruptions data needed to calculate MAIFI at a feeder level for those feeders originating at its own zone substations.
Momentary interruptions due to feeder section outages (MAIFI)	• MAIFI has been calculated on the basis of kVA interrupted, rather than the number of customers interrupted, as agreed with the AER as part of the Aurora Distribution Determination.	
Template 5c – Causes of Outages		
Causes of outages	• Template 5c contains the total number of outages split by cause, using a COUNTIF from the template 5a data (network data outages). • The COUNTIF totals do not accurately reflect the total number of outages, as template 5a splits outages by communities affected, meaning one outage can affect multiple communities (and therefore have duplicate rows). • This results in outages affecting more than one community being counted more than once in template 5c.	

Item	Schedule 1 – Paragraph 1.1(c)(i) Assumptions and methodologies	Schedule 1 – Paragraph1.1(c)(ii) Information cannot be provided or is not provided in full
Template 6 – Weighted Average Cost of Debt		
Weighted average cost of debt (%)	• Aurora's debt portfolio (including 11am borrowings) is managed by Aurora's Group Treasury on a consolidated basis, on behalf of both the Distribution and Energy Businesses. • Finance charges are allocated to the Distribution and Energy Businesses based on the amount of debt attributed to each business. • Accordingly, the WACD has been calculated on a whole of portfolio basis, and is equally applicable to the Distribution and Energy businesses.	

<table>
<tr><th>Item</th><th>Paragraph 1.1(c)(i)
Assumptions and methodologies</th></tr>
<tr><td colspan="2">Template 7 - Asset installation</td></tr>
<tr><td colspan="2">General assumptions and methodologies</td></tr>
<tr><td>All asset groups/categories</td><td>The following assumptions and methodologies apply to all asset groups/categories.
Asset replacement volumes
• Asset replacement volumes and failure statistics have been provided on a financial year basis.
Replacement life – mean calculation
• The mean asset replacement lives are as per Aurora’s response to section 6.9 of the RIN for the Aurora Regulatory Proposal 2012-2017. These means reflected the expected lives used for asset management and planning purposes.
• The mean replacement lives reported in template 7 represent the average age of the assets currently in service and are calculated by summing the combined age of each asset type (in whole years), based on the relevant age profile, and dividing the total age by the total number of assets in service.
Replacement unit costs
• Unit replacement costs reflect the rates applied to different task types in Aurora’s POW management system, WASP.
• Those rates include labour, materials, overheads and subcontractor costs, consistent with the basis on which the unit rates for Aurora’s POW were built-up as part of Aurora’s Regulatory Proposal.
• Replacement unit costs have not been provided for those assets that are no longer installed by Aurora, or are replaced with a different asset.
Asset failures
• Aurora’s Outage Reporting System (ORS) is the source of the asset failure statistics reported.
• The ORS draws on a log of all outages affecting customers, whether planned or unplanned. For each outage, one of the attributes recorded is the cause of the outage, which can include the failure of an asset. This information enables statistics to be gathered regarding the number of outages that have been caused during a given period by the failure of different types of asset.</td></tr>
</table>

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• However, the failures reported against each asset category relate only to failures which have resulted in an unplanned outage, and do not include instances where an asset has been found not to be performing to its specification and has subsequently been decommissioned during a planned outage. This is because the systems that initially capture information relating to outages only recognise the cause of planned outages as being a "planned outage", which provides no intelligence as to the underlying cause. • Therefore, the asset failure numbers provided are understated and the replacement volumes themselves provide a more accurate (albeit not exact) guide to the number of assets which have failed, because they include the replacement of assets in response to an unplanned outage, as well as the planned replacement of assets. • It is noted, however, that in the case of some asset types, such as transformers, that may be replaced in order to address capacity limitations, the number of assets replaced may include replacements for the purposes of augmentation, rather than addressing failures, meaning that the total replacement volume may be more than the total volume of failures. • Analysis of asset failure is also only possible at a high level, i.e. at asset category/group level, as the ORS is largely unable to identify either the particular asset or the specific type of asset that causes an outage, meaning that alternative means of allocating asset failures to specific types of assets within asset category/groups have been employed. **Total [asset] quantities** • Current asset quantities are reported as at 31 August 2013 and do not reflect the construction or decommissioning of any assets after that date, or changes in Aurora's asset base prior to that date for which data had not yet been captured. **Asset age profiles** • Asset age profiles are presented on a calendar year basis, because the lack of detail in Aurora's asset records regarding the month in which many assets with recorded installation dates were actually commissioned prevents Aurora from reliably determining or modelling asset age profiles on a financial year basis. • This means that the number of assets commissioned in calendar year 2013 and reported as part of the asset age profile for distribution system assets will be updated in Aurora's 2014 RIN response, in order to reflect asset replacement volumes for the full calendar year 2013 and negate any lags in the capture of data relating to the commissioning of new and/or replacement assets.
Poles	• The data provided in relation to poles is sourced from Aurora's Intergraph G-Technology GIS system, WASP and Aurora's Spatial Data Warehouse, which draws together information from those, and other sources.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Age profile • Many of Aurora's poles were installed by Aurora's antecedent DNSP (the Hydro-Electric Corporation) prior to Aurora coming into being in 1998, with the oldest having been in service since the early 1950s. • Since 2008 and the introduction of the G Tech GIS, the install dates for new poles have been recorded in a DD/MM/YYYY format. However, for many older poles specific installation dates have not been captured, either by the HEC or Aurora, and amongst those poles with recorded installation dates, in many cases 1 January in the year of installation, or simply the year of installation, has been specified as the installation date, regardless of when in the year the pole was actually installed. • Consequently, the age profile of Aurora's poles has been derived using a number of different methodologies, which seek to work around the inconsistencies in the availability of installation dates for different pole types and periods in time. • Further, since mid-2010, the processes used by Aurora to capture pole data have undergone revision. Information about Aurora's poles was formerly captured by personnel dedicated exclusively to the gathering of pole data, which resulted in every new pole being captured within a maximum of 12 months following installation. • Pole data is now being captured either through in-field work processes, or by pole inspectors operating under a five year inspection cycle, hence delays of over 12 months may be experienced in the data capture process. This impact is visible in the low reported numbers of poles installed since 2010. • Rules applying to the recording of new poles in Aurora's GIS require that poles can only be added to the database when they have been assigned a Pole Tag ID and their installation has been confirmed. If no confirmation is received from the field of a pole having been erected, a record of the new pole may not be added until the pole is next inspected, which may not occur for another five years under Aurora's current inspection regime. • This means that there are likely to be a number of poles constructed since 2008 for which there is currently no record, and while Aurora's new processes are capturing more comprehensive information about individual poles than was gathered prior to 2008, the time taken to do so in some cases means that Aurora has less complete information about its poles in the shorter term, and will continue to do so until improved in field capture tools are developed. As a result, the number of poles installed since 2008 for which there is currently no record has been estimated.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Natural wood poles • Aurora has recorded installation dates (by year) for 41 per cent of its current population of natural (untreated) wood poles. The earliest recorded use of natural wooden poles was in 1959 and their use was discontinued in 1994. All wooden poles with recorded installation dates after 1994 are, therefore, assumed to be treated pressure impregnated (PI) poles, on the basis that the installation date is a data error. The number of poles affected by this is not, however, significant. • In developing an age profile of Aurora's entire population of natural wood poles, the poles with no recorded installation date have been apportioned across the period during which this type of pole is known to have been in use (1959-1994), based on the age profile of the natural wood poles for which installation dates are available. • The mean replacement life for natural wood poles is deemed by Aurora to be 30 years, while the mean replacement life for staked natural wood poles is deemed by Aurora to be 45 years. • The replacement life (mean) for natural wood poles and the improvement in asset longevity achieved through staking is outlined in Aurora's Asset management Plan – Overhead and Structures. Aurora records the staking of individual poles as a distinct attribute in its GIS. • It is noted that emerging issues with natural wood poles failing due to water damage underneath possum guards saw a significant rise in the number of natural wood poles replaced during 2013, which skewed the ratio of pole staking to replacement over the five period on which the ratio was based. However, it is considered that the number of natural wood poles replaced is likely to continue to be impacted on by similar failures for the foreseeable future, given the widespread fitment of the type of guard in question. **Pressure impregnated wooden poles / Copper-Chrome Arsenate (CCA) poles** • PI wooden poles - also known as CCA treated poles (Copper-Chrome Arsenate) - are the only poles used by Aurora with an identifiable date of manufacture (recorded on an ID disc affixed to each pole by the manufacturer). In the absence of specific installation dates, the date that a pole was manufactured has been used as a proxy for its installation date, although most installation dates for PI poles have been recorded as being either the 1st January in the given year of manufacture, or the year of manufacture, rather than a specific date of manufacture. • As natural (untreated) wooden poles have not been used in Tasmania since 1994, all wooden poles with recorded installation dates from 1 January 1995 onwards are assumed to be treated PI poles. This is significant only from the point-of-view of providing Aurora with a means of identifying data errors in relation to the installation dates of natural wood poles.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• Aurora has installation dates for 98% of PI poles. In deriving an age profile of Aurora's PI poles, the poles without recorded installation dates have been distributed in line with the age profile of the PI poles for which installation dates are recorded. • Aurora also undertakes condition based staking of PI poles to extend their replacement life. • The replacement lives (mean) for PI wood poles and increases in asset lives associated with the practice of staking are outlined in Aurora's *Asset Management Plan – Overhead and Structures*. • Aurora records the renewal and staking of individual poles as a work task and as an attribute in WASP and the GIS. • The ratio of staking and renewal varies with age, the details of which are in the plan. • The standard (mean) replacement life for a PI CCA wooden pole is deemed by Aurora to be 45 years. However, CCA poles that are more than 10 years old are subject to routine testing (every five years), and as poles reach the end of their nominal asset life, this assessment of a pole's condition determines whether replacement is required, or the operational life of the pole can be extended through staking. • Aurora works on the basis that the staking of PI wood poles extends their replacement life, on average, by 15 years. • The mean replacement life for PI CCA wood poles that have been staked is deemed by Aurora to be 60 years. **Steel and concrete poles ('Stobie' poles)** • Based on an analysis of recorded installation dates, steel and concrete poles were installed by the HEC between 1952 and 1989 (although there are instances of Stobie poles being installed after 1989 as part of special projects requiring the particular properties of a Stobie pole. • Aurora has recorded installation dates for 65 per cent of its steel and concrete poles, almost all of which fall within this date range. The population of Stobie poles without recorded installation dates has been distributed across the period during which the poles are known to have been in regular use (1952-1989) in line with the age distribution of the steel and concrete poles for which credible installation dates are available. • Steel and concrete Stobie poles are deemed by Aurora to have a mean replacement life of 60 years. **Steel lattice poles** • Steel Lattice poles are understood to have been installed by the HEC in the 1960s and 1970s. However, Aurora has recorded installation dates for less than 1 per cent of all steel lattice poles, which is not considered a sufficient sample to provide reliable guidance regarding the ages of the steel lattice poles for which no installation date has been recorded. • For the purposes of developing an age profile of Aurora's steel lattice poles, poles without recorded installation dates have been

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	distributed evenly across each of the years bookended by the first and last known installation dates (recorded in years) for this type of pole. Records of more recent installation dates for this type of pole are not considered credible, and the poles in question have been distributed across the wider age profile on the same basis as steel lattice poles with no known installation date. • The mean replacement life for Steel Lattice poles is deemed by Aurora to be 60 years. **Steel-Rail/RSJ poles** • No installation dates are available in relation to the population of steel-rail/RSJ poles recorded in Aurora's asset registers. However, based on previously documented business knowledge, steel-rail poles are thought to have been installed by the HEC between 1963 and 1973, although it is not possible to be completely certainty about the exact point at which this type of pole was first used or precisely when the use of steel-rail poles was phased out. Nonetheless, the contention that steel-rail poles were used during this period has been adopted by Aurora for the purposes of its asset management activities, and given the very small number of steel-rail/RSJ poles still in use, it is considered that the lack of more precise asset installation information is not material in terms of its impact on Aurora's expenditure on asset replacement. • In the absence of recorded installation dates, the age profile of Aurora's steel-rail poles has been spread evenly across the years from 1963 to 1973 inclusive. • The mean replacement life for Steel Rail (RSJ) poles is deemed by Aurora to be 60 years. **Steel Lattice Towers (previously EHV Towers)** • Installation dates are not available for the small number of steel lattice towers (previously known as 'EHV' towers) recorded in Aurora's asset registers. However, based on previously documented business knowledge, it is accepted within Aurora that steel lattice towers were installed in Tasmania from 1955 to 1965. • Although it is possible that some towers may have been installed prior to 1955 and/or after their use was purportedly discontinued in 1965, this degree of imprecision is deemed to be acceptable for Aurora's asset management purposes. In the absence of recorded installation dates, the age profile of Aurora's steel lattice towers has been distributed evenly between the years spanning from 1955 to 1965, inclusive. • The mean replacement life for Steel Lattice Towers is deemed by Aurora to be 75 years.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Concrete poles • Amongst the small number of concrete poles currently in service, only three do not have recorded installation dates. These poles were incorporated into the age profile for this type of pole in the year after the majority of concrete poles were installed. • The mean replacement life for concrete poles is deemed by Aurora to be 60 years. **Steel (Other) poles** • Aurora has recorded installation dates for 48 per cent of the steel (other) poles currently in service. To develop an age profile of Aurora's steel (other) poles, poles without recorded installation dates have been distributed across the age profile consistent with the age profile of the steel (other) poles for which installation dates are available. • The mean replacement life for all other Steel poles is deemed by Aurora to be 60 years. **Asset replacement volumes** • Asset Replacement Volumes are sourced from the condition based replacements recorded in WASP. **Asset failures** • Asset failure data is obtained from the ORS, which records the underlying cause of each outage. The reported asset failure numbers are based on analysis of the outages which occurred during 2012-13. • However, the ORS does not establish the specific asset or identify the asset type that failed, with outages attributed to failures at the asset group/category level (e.g a failure of a pole rather than a PI wooden pole as opposed to a Stobie pole). • Consequently, as a general rule the number of outages attributed to each group/category of asset has been divided between the asset types that make up that group/category on a pro-rata basis, based on the number of each type of asset in service. • This assumes an even rate of failure across the different asset types which make up each asset group/category. This assumption was adopted in the absence of reliable data to support an alternative means of attribution. **Total quantity** • The total quantities of each type of pole have been extracted from Aurora's asset registers, with the only estimate of pole quantities being the aforementioned estimate of the (small) number of PI wood poles installed since 2008 for which there may not yet be a confirmed record in Aurora's asset registers.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
Pole top structures	• Pole top structures and equipment, such as cross arms, conductor ties and insulators, are deemed by Aurora to be part of a pole's structure, and while Aurora maintains a list of components for each pole, separate records of the age and type are not maintained for these components. • The only pole mounted equipment for which records are maintained by Aurora are transformers and switchgear (the latter being reported under the asset category of OH System Switchgear). • Information regarding pole mounted transformers is sourced from Aurora's GIS. Historically, Aurora has recorded the installation dates of pole mounted transformers. Other data captured and recorded at the time of installation includes details of each transformer's construction, its rating and other electrical parameters. Details on the make and model of transformer have not, however, been captured. **Age profile** • The information provided regarding the age of Aurora's pole mounted transformers has been determined on the basis of installation dates held within Aurora's GIS for each transformer. • In the absence of a specific attribute in Aurora's GIS to indicate whether a transformer's outside tank has been galvanised the age of each transformer has been used as in indicator of which transformers are galvanised, on the basis that all transformers put into service from 1990 onwards have been galvanised. • The expected replacement life of non-galvanised pole mounted transformers is deemed by Aurora to be 42 years, while galvanised transformers have an operational life expectancy of 50 years. **Asset replacement volumes** • Aurora does not undertake the replacement of pole mounted transformers on the basis of age, with replacement usually being undertaken in response to asset failure or the emergence of capacity/voltage constraints. Asset replacement volumes relating to distribution transformers are obtained from WASP. **Asset failures** • Asset failure statistics for pole mounted transformers are derived from the ORS. It is noted that in recording the failure of a pole mounted transformer as the cause of a particular unplanned outage, the ORS does not record the specific asset which failed or distinguish between the various types and sizes of transformer listed in the RIN response template. • The number of asset failures has, therefore, been attributed across the various types of pole-mounted transformer listed in the RIN response on a pro-rata basis, based on asset numbers.

<table>
<tr><th>Item</th><th>Paragraph 1.1(c)(i)
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<tr><td></td><td>• Other pole top structures and equipment, such as insulators and cross-arms, are not recorded separately in Aurora's asset registers, and component level asset failures are not recorded in Aurora's outage management and reporting systems as the cause of unplanned outages.
Total quantity
• The total quantities of each type of pole mounted transformer have been extracted from Aurora's asset registers.</td></tr>
<tr><td>Conductors</td><td>• Aurora, and the HEC before it, has used a variety of LV and HV conductors, all of which are described below.
• The asset data provided in relation to conductors has been extracted from G-Tech, Aurora's GIS, WASP (replacement unit costs, asset replacement volumes) and ORS (failures).
Low voltage conductors
• The descriptive information available regarding LV conductors (i.e. 'bare' conductors) is limited, and includes only whether a given conductor is overhead or underground and the relevant voltage. No information is recorded regarding the size, material or type of conductor, or the date on which a conductor was installed.
• Aurora's GIS does identify LV Conductor functionality, however, specifically:
  • LV_Span – predominantly LV Bare conductors serving as the main distributor between poles;
  • LV_Service_Span – predominantly LV ABC serving as a take-off from a LV_Span between poles specifically for the purpose of providing a service take-off for a customer; and
  • LV_Service – an LV conductor supplying one customer at their connection point.
Copper (Cu)
• Based on historical information, it is understood that copper cables were first used in Tasmania as LV conductors in 1945, while their use was discontinued in 1963.
• LV copper conductors are deemed by Aurora to have a mean replacement life of 50 years.
AAC
• AAC - Imperial stranded All Aluminium Conductor was used in Tasmania as a LV conductor from 1963 up to 1974. The metric version of AAC was introduced in 1974 when Australia converted to metric units of measurement. The range of AAC in use was rationalised by the HEC in 1986, with the use of three types of AAC conductor (7/2.50, 7/3.00 and 7/3.75) being discontinued.</td></tr>
</table>

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• As a large percentage of the original AAC that was installed in the early 1960s is still thought to be in good condition, the mean replacement life is now estimated to be greater than 60 years. Trials are being conducted by Aurora to verify this. **LV ABC** (Aerial Bundled Conductor) • LV ABC was first introduced as a LV conductor by the HEC in 1989 and is currently still utilised by Aurora where required. The significant majority of new LV conductors are ABC. • The average replacement life of LV ABC is deemed by Aurora to be 60 years. **Overhead services** • The mean replacement life of overheard service wires is deemed by Aurora to be 40 years. The oldest conductors currently in service were installed in the mid-1960s. From 2004, Aurora has undertaken a service wire replacement programme which has involved replacing overhead services that meet certain criteria whenever the performance of other services by the Distribution Business presents the opportunity to do so. • This opportunistic replacement of overhead services has resulted in a material increase in service wire replacements since then. **High voltage conductors** • Aurora has better quality information available in relation to its HV conductors, including for each HV conductor segment the conductor's size (diameter), material and the length of the segment. Historically Aurora has not recorded installation date for HV conductors, however, and only changes to Aurora's GIS made in mid-2010 have enabled this information to be captured for new HV conductors. **Galvanised Steel (GI) conductors** • No 8 - was used as an inexpensive conductor in the rural electrification program that occurred in Tasmania immediately after the end of the Second World War. It is assumed that this type of conductor was used into the 1960s. • 3/12 - is an imperial gauge 3-stranded steel wire conductor that was used from 1960 until 1974. • 3/2.75 - is the metric equivalent of 3/12 galvanised steel conductors, that was introduced in 1974 when Australia adopted metric units of measurement and is still used today. • 7/16 – no information is available regarding the installation of 7/16 GI conductors in HV applications. • GI conductors have not been used for LV elements of the distribution network.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• The average replacement life of GI conductors is deemed by Aurora to be 50 years, or 40 years where installed in coastal environments. **Copper (Cu)** • It is understood that copper conductors were first used in HV applications by the HEC in 1945. The use of copper conductors was discontinued in 1963. Copper conductors were used for LV lines during the same period. • The average replacement life of copper conductors is deemed by Aurora to be 50 years. **ACSR** • ACSR - Imperial stranded Aluminium Conductor Steel Reinforced was used by the HEC from 1960 until 1974. • ACSR - The metric version of ACSR was introduced in 1974 when Australia went metric. Its use was discontinued in 1986 when the number and type of standard conductors being used was rationalised by the Hydro-Electric Commission. • ACSR has not been used for LV lines in Tasmania. • The average replacement life of LV ABC is deemed by Aurora to be 50 years. **AAC** • Imperial stranded All Aluminium Conductor (AAC) was used in Tasmania from 1963 until 1974. The metric version of AAC was introduced in 1974 when Australia adopted metric units of measurement. The range of AAC in use was rationalised by the HEC in 1986, with the use of 7/2.50,7/3.00,7/3.75 AAC being discontinued. • As a large percentage of the original AAC that was installed in the 1960s is still in good condition, the Replacement Life for this type of conductor is now estimated to be greater than 60 years. Trials are being conducted by Aurora to verify this. **AAAC** • 7/3.00 All Aluminium Alloy Conductor (AAAC) was introduced in 1986 as the replacement for ACSR conductors. AAAC was only used for lighting switch wire on the LV network. **HV ABC** (Aerial Bundled Conductor) • HV ABC was first introduced in 1994 and is still utilised where required. The replacement life (mean) for HV ABC is 40 years, as per the Asset Management Plans provided to the AER in 2011.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Age profile • The age profile for HV conductors has been derived using knowledge of the periods during which different type of HV conductor have been used by Aurora (and the HEC before it), along with historical records of the (estimated) annual volume of HV conductor installed during those periods. • The age profile since 2010 has been derived on the basis of the installation dates recorded in Aurora's GIS system for each segment of HV conductor. The age profile and asset quantities supplied in response to the RIN are consistent with the age profile provided to the AER in 2011, with the addition of the actual quantities of conductors installed during the past three years. • In the absence of installation dates for LV conductors, the age profile for those assets has been based on the previous age profile for LV conductors supplied to the AER in 2011, which was based on knowledge of the periods during which different type of LV conductor have been used by Aurora and the HEC before it (see above), along with historical records of the (estimated) annual volume of LV conductor installed during those periods. • In the absence of recorded installation dates for overhead services, the age profile of overhead services has been developed by using estimates of the annual number of servicing tasks (new and upgraded services) and replacements undertaken over the past five years to distribute the total number of overhead services across an age profile beginning in 1965. Aurora performs approximately 4,500 servicing tasks annually and replaces around 6,000 overhead services, either in response to faults or as part of replacement programs. As with other conductors, the age profile of overhead services is expressed in kilometres, rather than installation numbers. **Total quantity** • For all types of conductor, with the exception of overhead services, conductor quantities (expressed in kilometres) are a calculated value, derived using Aurora's GIS system. Aurora holds linear features within its GIS (i.e. strings of coordinates representing roads and powerlines) that allow for the accurate determination of cable lengths. • In the case of HV conductors, because Aurora has records of the conductor material used for each HV conductor segment, the quantity of each conductor type accurately reflects the various types of conductor in use. • Despite there being a number of LV conductor types (Copper, AAC and ABC) which have been used by Aurora, and the HEC before it, because the recorded information regarding LV conductors does not include the size, material or type of conductor, Aurora has not been able to provide quantities, either calculated or estimated, for the different types of LV conductor in service as either LV spans or service LV spans based on material, and has had to broadly categorise its LV conductors as either 'Bare' conductors (of indeterminate type) or ABC conductors.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• In the case of LV conductors (excluding overhead services), the total line length has been calculated – as with HV conductors – on the basis of linear features recorded in Aurora's GIS, with the total allocated between the different LV conductor types based on knowledge of the different types of LV conductor and the periods in which they were used, and the age profile. • Aurora does not, however, record the elevation of its power lines, hence all spans are deemed to run on a 'flat earth' basis, and sag is not taken into account. • While this introduces a degree of inaccuracy into Aurora's line length calculations, and it is likely that Aurora's estimates of conductor lengths are understated, this level of precision is deemed sufficient for the purposes of Aurora's asset management activities. • In the case of LV overhead services, the exact length of each service is not recorded, nor its exact path between the point of supply and the customer's point of attachment. With no linear data on which to base any calculations of length, the total length of LV overhead cabling in service is derived by multiplying the total number of connections by a standardised length (15 metres). **Asset replacement volumes** • Asset replacement volumes for all conductors are measured in terms of the combined length of conductors replaced (expressed in kilometres), except for overhead services, in which case the asset replacement volume represents the number of service wires that have been replaced. • For HV conductors, asset replacement volumes are sourced from summary of the data relating to Aurora's condition-based replacement program which is maintained in WASP. • Aurora is unable to provide asset replacement volumes in relation to LV ABC because Aurora has no record in its GIS of conductor type, material or size. • On average, around 6,000 overhead services are replaced each year, of which around 1,500 are attributable to asset failure, while the remainder (approximately 4,500) are pro-active replacements, carried out as part of a service wire replacement programme. Under this programme, service wires are replaced when the performance of other services by the Distribution Business presents the opportunity or creates an impetus to do so (e.g. pole replacement, LV conductor work, investigation of electrical faults involving a broken neutral - detected using a CablePI alarm, and line clearance work). **Asset failures** • For all conductors, asset failure numbers are shown in terms of the incidences of failure, rather than the length of conductors which have failed.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• Asset failure statistics have been obtained from the ORS and are based on analysis of the recorded cause of each outage that occurred in 2012-13. This system, however, while able to recognise conductor failure as the cause of an outage, is unable to establish the specific location or type of conductor that failed, hence the number of overhead conductor failures (with the exception of overhead services) is attributed across the population of conductor types on a pro-rata basis, based on the quantity of each LV conductor in service. • In the case of overhead services, while Aurora's outage management systems record the failure of an overhead service as the cause of a customer outage, no distinction is made between failures that are due to the failure of a service fuse, as opposed to a service wire. Therefore, the reported number of overhead service failures – while providing a reliable indicator of LV service failures, inherently overstates the number of overhead service wires that have failed. • Of the 6,000 overhead services that are replaced each year, around 1,500 are attributable to asset failure, while the remainder (approximately 4,500) are pro-active replacements, carried out as part of a service wire replacement programme.
Underground cables	• Data about Aurora's underground cables is sourced from Aurora's GIS. • Historically, Aurora has not captured installation dates for underground LV or HV cables, and only recent changes to the GIS (made in mid-2010) have enabled installation dates to be recorded against specific cables that are installed in the future. This is the same for HV and LV terminations. • Aurora's GIS does record cable size and material, however detailed information regarding construction is not available in relation to HV cables, although basic construction details are recorded for LV underground cables. **Age profile** • In the absence of a record of installation dates for underground cabling in Aurora's GIS, an age profile of the HV underground cables which are currently in service has been taken from Aurora's *Underground System Management Plan* (as provided to the AER in 2011), which reflects the periods during which each type of cable has been in use in Tasmania and the amount of cabling installed in each year. • Aurora's *Underground System Management Plan* also provides an age profile of the LV underground cables which are currently in use, again reflecting the periods during which each type of cable has been in use in Tasmania and the amount of cabling installed in each year. **Asset replacement volumes** • Asset Replacement Volumes are sourced from documented annual Asset Replacement Programs for 2012-13.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Asset failures • Asset failure statistics are derived from the ORS. This system is, however, unable to identify and report on the specific cables that have failed or the particular type of cable that failed. • The total number of underground cable failures has, therefore, been attributed between cable types on a pro-rata basis, based on the reported quantities of each cable in service, adjusted to reflect known issues with one particular type of LV cable (CONSAC) which is known to be failing more frequently than the volume of the cable in service would suggest. • Age is not a specific contributor to asset failures for cables. • The difference between HV and LV cable failures is distributed based upon the system affected by the outage, e.g. LV, transformer (assumed LV cable), and control station, recloser or circuit breakers (HV cable). • In the case of underground cables, the number of asset failures represents the recorded incidences of failure (resulting in an unplanned outage), whereas the replacement volume reflects the aggregate amount (length) of cabling that was replaced. **Total quantity** • Whether LV or HV, the quantity of each type of underground cable in service is expressed in kilometres. Terminations, however, are expressed in terms of the number of assets in service. • As with overhead conductors, underground HV cable lengths are able to be determined using linear features within Aurora's GIS. Calculated cable lengths are, however, only as accurate as the placement of the linear features which inform the calculation, and the significant majority (99.9%) of cables are not located and placed spatially, hence their placement indicates their general location and route only. • While this introduces a degree of inaccuracy into Aurora's line length calculations, and it is likely that Aurora's estimates of conductor lengths are understated, this level of precision is deemed sufficient for the purposes of Aurora's asset management activities. • While more accurate location information is available in CAD files in relation to underground cabling, the calculation of length from those files is a significant computational exercise, and would still not entirely eliminate inaccuracies in the results. **Asset replacement volumes** • Asset replacement volumes for underground cables reflect the length of each type of cable replaced during 2012-13. Asset replacement volumes for terminations, however, reflect the number of assets replaced.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• Cables which have failed (resulting in an unplanned outage) are generally repaired at the point of failure rather than replaced, meaning that cable failures are not reflected in, or a driver of cable replacement volumes. • Cable replacement volume is, instead, a product of Aurora's planned Asset Replacement Programs. In 2013 Aurora only had one active Asset Replacement Program for underground cabling, which related to Concentric Neutral Solid Aluminium Conductor (CONSAC) installed in residential subdivisions from 1971 until 1980. • Aurora currently has no active HV cable replacement programmes and no HV cable was replaced in 2012-13.
Services (inc. LV pillars service pits)	**Age profile** • Historically, Aurora has not captured or recorded installation dates for LV service pillars/turrets, and only changes to Aurora's GIS made in 2008 have enabled installation dates to be recorded. • Aurora's GIS does, however, store information as to the location of service pillars/turrets, and the basic type of pillar/turret installed. • Aurora's 2011 Management Plan for Underground Systems (previously submitted to the AER) provides an age profile of the LV service pillars/turrets which are currently in use. The age profile provided in Aurora's RIN response for the different types of street furniture currently in service is consistent with Management Plan submitted in 2011. **Asset Replacement Volumes** • There are no asset replacement programs in place for service pillars / turrets, with ad hoc replacement generally occurring only in response to damage inflicted by third parties. Aurora has no centralised process in place to capture the replacement of turrets. **Asset failures** • Asset failure statistics are derived from the ORS. However, there are no asset failures recorded against LV Furniture. • Asset failures involving service pillars/turrets – even when the replacement of a turret/pillar is required – are not recorded as a pillar/turret failure, on the basis that the 'failure' is typically attributable to either third party damage (by vehicles etc.), or relates to the failure of components housed within the turret/pillar, such as cables or cable connections, rather than the pillar/turret itself. In the case of the failure of an asset housed within a turret, the failure would be recorded against the type of asset which has failed, rather than the pillar or turret housing the asset. **Total quantity** • The total quantities of LV cabinets and turrets in service have been extracted from Aurora's asset registers.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
OH System switchgear	• The data presented is primarily sourced from Aurora's GIS. For the vast majority of overhead system switchgear, Aurora's GIS currently stores only the location of the switchgear and information regarding the basic type of switchgear fitted. • Additional data is available from WASP and spreadsheet-based asset registers in relation to reclosers and gas switches (including make, model and serial number). **Age profile** • Historically, Aurora has not recorded installation dates for overhead switchgear, and only changes to Aurora's GIS in 2008 have enabled this information to be recorded. While generally better information is available in Aurora's GIS in relation to reclosers and gas switches than for other overhead switchgear, installation dates have been derived from other information sources, such as asset management plans, and controlled spreadsheets containing other attributes not available within Aurora's GIS. • Consequently, the age profile for basic overhead switchgear has been developed in accordance with assumptions about general usage of each type of switchgear. **Asset replacement volumes** • Whilst condition assessment of OH system switchgear is undertaken routinely, Aurora does not actively check its operation. The replacement of overhead switchgear is driven by failures of switchgear to perform its function (that are identified during operation), which can include performance related issues such as a misalignment of blades or overheating connections. • Replacement volumes are sourced from jobs created in WASP as some overhead switchgear failures go undetected because they don't result in an outage, and are often only discovered as part of the investigation of the failure of another asset, such as a pole or transformer failure resulting from a lightning strike. (Switchgear failure is also not able to be recognised as the cause of an outage in Aurora's outage management and reporting systems). **Asset failures** • Asset failure statistics for distribution switchgear are derived from the ORS. **Total quantity** • The quantities of overhead switchgear in service have been extracted from Aurora's asset registers.
Regulators	• Aurora's GIS houses information as to the location of regulators and their basic type only. Other data is available in relation to regulators in WASP and controlled spreadsheet-based asset registers.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Age profile • Historically Aurora has captured installation dates of regulators. • The age profile for regulators has been profiled across the population in accordance with installation dates extracted from GIS and spreadsheet data. **Asset replacement volumes** • Replacement is based upon capacity, or condition / failure. • There are no time based replacement programs. **Asset failures** • Asset failure statistics in relation to regulators are derived from the ORS. **Total quantity** • The number of regulators in service has been extracted from Aurora's asset registers.
Distribution transformers	• Aurora has applied the asset category of distribution transformers to its ground mounted substations, with pole mounted transformers being treated as pole top structures for the purposes of Aurora's response to the RIN. • For the purposes of Aurora's response to the RIN, Aurora has defined a number of 'standardised' categories of ground mounted substations , which reflect common combinations of select attributes, based on the type of substation building/enclosure and the key components within it, such as transformers and both HV and LV switchgear. All information extracted in relation to a given substation has been extracted on this basis. • Data relating to ground mounted substations has been sourced using a combination of Aurora's GIS, WASP and spreadsheet-based asset registers. **Age profile** • Aurora's GIS records an installation date for each substation, reflecting the date on which the site was first commissioned. The installation date for each substation may be different to the installation dates of the various equipment within the site. **Asset Replacement Volumes** • In general, the replacement of ground mounted substations is undertaken to address capacity limitations, or in response to asset condition or failure. However, at a component level there are specific HV Switchgear and LV switchgear replacement programs which involve switchgear installed in ground mounted substations.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	• The programs are outlined in the asset management plan. **Asset failures** • Asset failure statistics are derived from the ORS. **Total quantity** • The number of ground mounted distribution substations in service has been extracted from Aurora's asset registers.
Zone transformers	• Aurora has only a small number of zone substations in its system, with approximately half of the distribution feeders in Aurora's network emanating from terminal substations operated by Transend Networks. • Aurora has both urban and rural zone substations. • Information about zone substations has been compiled at a level that includes the key components of each site, such as the enclosure, transformers, HV switchgear and protection equipment. • Information relating to zone substations and their related equipment has been profiled using a combination of GIS data, information from WASP and spreadsheet based asset-registers. **Age profile** • The age profile for zone substations is based on the installation date of each substation, however it is noted that this may be different to the equipment within the site. **Asset replacement volumes** • In general, the replacement of zone transformers is undertaken in response to the emergence of capacity limitations, or in response to asset condition/failure. • There are specific HV switchgear replacement programs for zone substations to manage the risks associated with ageing switchgear. However, the low volume of this type of asset in service means that replacement volumes are also very low. • The relevant asset replacement programs are outlined in the management plan. **Asset failures** • Asset failure statistics are derived from the ORS. **Total quantity** • The number of zone transformers in service has been extracted from Aurora's asset registers.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
Zone switchgear	• The data provided regarding zone switchgear has been sourced from Aurora's GIS, WASP and spreadsheet-based asset registers. **Age profile** • The year of installation for zone substation switchgear has been profiled using a combination of GIS data, information held in WASP and the aforementioned spreadsheets. **Asset replacement volumes** • In general, the replacement of zone switchgear is based upon risk, or asset condition/failure, and there are specific HV Switchgear replacement programs in place. • The programs are outlined in Aurora's asset management plans. **Asset failures** • Asset failure statistics for zone switchgear are derived from the ORS.
Zone 'other assets'	• Most of the information regarding this class of assets is maintained using a combination of WASP and spreadsheets. The GIS does not contain data relating to other assets, including batteries. **Age profile** • The years of installation for other assets are derived from the known age profile for the buildings in which they are housed, and spreadsheet-based asset registers. **Asset Replacement Volumes** • Zone Substation other assets, specifically buildings, are replaced only when major refurbishment occurs. • For battery units, a replacement program is in place as outlined in the asset management plan. **Asset failures** • Asset failure statistics for this type of asset have been compiled using the ORS. **Total quantity** • Information regarding the quantity of Zone other assets in service has been sourced from Aurora's asset registers.
SCADA and protection	• The data provided relating to SCADA and protection systems has been sourced from Asset Management Plans as Aurora's GIS does not contain data relating to secondary assets.

Item	Paragraph 1.1(c)(i) Assumptions and methodologies
	Age profile Aurora has upgraded and constructed a number of zone substations during the course of the past decade, and the implementation of SCADA has been part of that work. However, Aurora does not hold specific information on the SCADA or protection systems in its zone substations and the age profile for SCADA and protection systems is generally related to the age of the zone substations in which systems are installed – unless the systems at a particular substation have been commissioned at a later juncture, as part of a specific program to either upgrade or retro-fit protection and control systems. **Asset replacement volumes** • In general, the replacement of SCADA and protection systems is based upon the age and capability of the existing system. • Aurora has a program to upgrade protection systems where required for system management purposes, which is outlined in Aurora's asset management plans. **Asset failures** • Asset failure statistics are compiled using the ORS. **Total quantity** • Aurora's GIS does not contain data relating to secondary assets, and the quantities of SCADA and protection systems have been sourced from Asset Management Plans and asset registers.

Paragraph 1.1(d) - Movements between statutory accounts and regulatory accounts

Aurora is required to explain all movements between the audited statutory accounts and the regulatory accounting statements for the 2012-13 Regulatory Year.

Adjustments between statutory accounts and regulatory accounts	
Item	**Details**
Income Statement	
ICAM adjustment opex to capex - $0.29m	• This adjustment relates to the “true-up” of indirect costs allocated to the Distribution Business (in accordance with Aurora’s ICAM). • This “true-up” compares the actual corporate costs incurred to the budgeted corporate costs which are charged to the Distribution Business in the management accounts. • The Distribution Business portion of this adjustment has been allocated in accordance with the CAM, based on direct labour hours, resulting in a portion being transferred to capital.
Regulatory depreciation v statutory accounts depreciation - $4.735m	• This adjustment represents the difference in depreciation as per the RAB valuation as opposed to the depreciation recorded in the statutory accounts. • These differences arise due to differences in asset values (valuations between the accounting and regulated books. • Certain assets, such as inventory, are held in the statutory accounts at cost but in the regulatory accounts at replacement cost. This differing value means that depreciation outcomes will be different.
Items allocated items to the Distribution Business net PBT impact of - ($73.15m)	• This adjustment represents income and expenditure not attributable to the Distribution Business, including Energy Business, AETV, Ezikey, finance charges, asset impairment losses and tax.

Adjustments between statutory accounts and regulatory accounts

<table>
<tr><th>Item</th><th>Details</th></tr>
<tr><td colspan="2">Balance Sheet</td></tr>
<tr><td>Current assets - $10.54m - Distribution inventory classification and valuation</td><td>• There is a difference in the treatment of inventory attributed to the Distribution Business between Aurora's statutory and regulatory accounts.
• The statutory accounts value inventory at cost, with inventories reported as part of current assets, whereas the Regulated Accounts classify inventory as a non-system asset which is treated as part of PP&E and held at CPI adjusted valuation.</td></tr>
<tr><td>Non-current assets - $4.95m - property plant and equipment</td><td>PP&E reconciliation
Recognise additional customer contributions in the RAB value (not adjusted in statutory accounts asset valuation) (3,761)
Adjustment for provision movement to align to AER methodology (as incurred cash) 6,741
ICAM credit adjustment reallocated from opex to capex (269)
Statutory depreciation adjusted to regulatory depreciation (4,735)
Inventory included in non-operational asset value 13,151
Fixed asset – difference in CPI valuation v historic cost (non system assets) (16,079)
Total difference (4,947)</td></tr>
<tr><td>Customer contributions - $3.37m credit</td><td>• This adjustment recognises additional credit in Aurora's RAB of $3.7m for customer contributions.
• This value was not correctly adjusted for in the statutory accounts year end RAB valuation.</td></tr>
<tr><td>Provisions movement - $6.7m debit</td><td>• This adjustment represents the adjustment to the RAB required to align with the AER's determination.
• The AER methodology requires expenditure to be recorded as incurred (i.e. on a cash basis). Based on this methodology, an adjustment is required to the value of 2012/13 additions to account for the movement of provisions, adjusted for non-cash flow items including the RBF actuarial adjustment and interest.</td></tr>
<tr><td>ICAM credit adjustment - $0.29m credit</td><td>• This adjustment represents the portion of the ICAM adjustment transferred to capital from operating expenditure.
• The ICAM adjustment has been allocated to distribution services in line with the approved CAM.</td></tr>
</table>

Adjustments between statutory accounts and regulatory accounts	
Item	**Details**
Regulated Distribution depreciation - $4.7m credit	• This adjustment represents the difference in depreciation as per the RAB valuation and the depreciation recorded in the statutory accounts. • Differences arise due to differing valuations of assets between the accounting and regulated books.
Inventory - $13.15m debit	(As discussed above under current assets)
Fixed assets - $16.1m credit	This adjustment relates to the difference in the valuation of non-system (minor assets) between Aurora's statutory and regulatory accounts, including: • CPI inflation adjustment applied to statutory accounts versus CPI inflated value in RAB. • Land carried at fair valuation in statutory accounts as opposed to historic costs plus inflation in the RAB. • Difference in the useful life for vehicles specified by the AER of 6 years, and the vehicle life of 9 years reflected in the statutory accounts (also differences due to historic RAB adjustments by OTTER to reduce value). • AER RAB valuation recognises expenditure as incurred during the year, which includes movement in work in progress (WIP), whereas the statutory accounts ignore WIP, and recognise additions only once the expenditure is able to be capitalised (e.g. the works are completed and ready for use). • The RAB recognises the value of motor vehicle disposals based on the proceeds from sale, whereas the statutory accounts recognise disposals on the basis of the profit or loss on disposal.

Paragraph 1.1(e) - Capitalisation policy

The Aurora Energy Capitalisation Policy for the 2012-13 Regulatory Year is provided in Appendix A.

Paragraph 1.1(f) - Statement of overhead allocation policy under Cost Allocation Method

Following is a statement of the policies applied by Aurora in the 2012-13 and 2011-12 Regulatory Years when allocating overheads to service segments in accordance with the CAM approved by the AER for the current regulatory control period.

Overheads have been allocated to the service segments in accordance with Aurora’s CAM. The CAM encompasses both the method and policy for the allocation of costs.

Sections 1.2 and 1.3 - Material differences between Regulatory Accounting Statements and Distribution Determination

For each of the items listed in the following table, Aurora is required to identify any material differences between its 2012-13 Regulatory Account Statements and the corresponding amounts provided for by the AER in Aurora's 2012-17 Distribution Determination, and provide details of the operational activities and/or drivers that caused each material difference.

Item	Forecast $'000 nominal	Actual $'000 nominal	Variance %	Explanatory information (paragraph 1.3)
Paragraph 1.2(a) **Total revenue**	276,000	266,204	-4%	• Forecast revenue as per the 2012-13 Pricing Proposal. • DUoS revenue has been impacted by milder weather conditions which have led to reduced levels of consumption by consumers. • Coupled with the impact of embedded micro-generation, this has led to an under-recovery of DUoS revenue.
Paragraph 1.2(b) **Total operating expenditure** **(standard control only)**	32,398	32,573	4%	• Operating expenditure variances detailed in template 10 (operating costs) table 2 (explanation of material differences).
Paragraph 1.2(c) **Total maintenance expenditure** **(standard control only)**	39,895	38,164	-4%	• Maintenance expenditure variances detailed in template 8 (maintenance) table 2 (explanation of material differences).
Paragraph 1.2(d) **Total actual capital expenditure** **(standard control only)**	116,459	98,511	-15%	• Capital expenditure variances are detailed in template 5 (capex) table 2 (explanation of material differences).

Section 1.4 - Classification of distribution services

Following is an explanation of the procedures and processes used by Aurora to ensure that its distribution services have been classified as set out by the AER in the 2012-17 Distribution Determination.

Cost capture and financial management systems

Aurora utilises a five-level hierarchical structure within its business management systems (BMS) for cost attribution against the general ledger chart of accounts:

1. Department: these are only used for internal business reporting and are not relevant to this methodology;
2. Activity: this defines expenditure as either capital works, operational activities or external works;
3. Work Program: there are multiple Work Programs for Aurora's capital works and operations;
4. Work Level: there are multiple Work Levels for each Work Program; and
5. Work Category: there are one or more work categories for each work level.

Each asset and work category is assigned to a category of distribution service as per the service classification hierarchy. By establishing a clear relationship between work categories and distribution services, the BMS ensures that costs are correctly attributed to the relevant distribution service. The work categories relate to operating expenditure or capital expenditure in accordance with Australian Accounting Standards. In this way, costs are automatically separated and allocated (at their source) to the appropriate distribution service category.

A work category describes all costs that apply to Aurora's regulated and unregulated activities. The work category dimension is at the base of the cost allocation hierarchy.

Each year, hundreds of thousands of transactions are automatically processed by the BMS. Aurora's chart of accounts and costing systems have been established so that both operating expenditure and capital expenditure can be separately accounted for and reported in accordance with Aurora's CAM and regulatory reporting requirements.

The chart of accounts structure enables costs to be automatically attributed directly to, or automatically allocated between, the categories of distribution services provided by Aurora.

All costs are captured in the financial system via a unique job number, with each job number linked to the dimension string according to the type of work being registered. An example is – Job Z/15464 - pole replacements – which would have the following dimension string:

(SCS) Standard Control –

(NDR) Reliability and Quality Maintained -

(POLE) Reliability & Quality Maint Poles -

REPOL (Pole Replacements)

This enables reporting to the AER of the costs incurred against each of the service classifications (as set out by the AER in the 2012-17 Distribution Determination). The chart of accounts structure mentioned above enables costs to be automatically allocated directly to, or split between, the categories of distribution services provided by Aurora.

Aurora's BMS provides an integrated approach to tracking costs from their original source to their ultimate attribution or allocation, regardless of whether these costs originate inside or outside of Aurora. The original source of the costs may be labour timesheets, purchase orders, requisitions, or invoices.

Costs are charged to work categories on a full cost recovery basis and do not incorporate any internal margins.

Registration of project cost numbers and approval process

To ensure jobs are registered against the correct Work Category, Aurora has a governance process which requires all POW jobs to be submitted to the Distribution Business Finance Team (Finance) for approval of the work category prior to the job being registered. The registering of jobs in the finance system is limited to Finance and planning teams to avoid/minimise incorrect jobs being created. During this process a check is undertaken against the project approval form, which is prepared by the relevant asset engineer, and outlines the type of work to be performed and the justification for the work being undertaken. This ensures the work category selected matches the nature of the work to be performed, and that the job is registered against the appropriate category in the financial service classification hierarchy.

The project approval forms are also required to be approved by senior technical engineers prior to submission to Finance for registration of the job.

Reporting and monitoring of costs

Finance distributes monthly reports to each asset manager in relation to each job for which they are responsible, outlining the costs incurred and detailing transactions against each service classification (work category). A review of the costs is undertaken and any anomalies investigated (e.g. if any incorrect allocations of costs are identified).

Aurora has established a program of work governance committee which consists of senior management from across the business and includes engineering, commercial and works management. The committee meets monthly and is charged with providing commercial oversight over expenditure on Aurora's program of work, and monitoring spending in accordance with the AER's service classifications. It also provides a forum to discuss future and current commercial and technical aspects of the business' investment decisions.

Quarterly expenditure reset/reforecast

Aurora undertakes a detailed review of expenditure incurred against each service classification as part of the quarterly expenditure re-forecasting process. The purpose of this process is to reforecast the expected end of financial year spends. This process engages stakeholders across the Business and provides an opportunity for detailed review and interrogation of the expenditure. This process assists with providing comfort that costs are being captured in the financial system and reported against service classifications as appropriate.

Cost allocation methodology

Aurora ensures compliance with the AER approved CAM, which sets out the methodology for allocating overheads to the different service classification types as determined by the AER. For each different overhead cost allocation pool (as per CAM) the process undertaken to ensure allocation of overheads in accordance with the CAM is as follows:

Network Services overheads (including a portion of Corporate and Shared Services costs)

- The CAM states that the recovery of this overhead cost pool against the service classifications must be based on the direct labour hours performed for each classification type.
- To ensure this occurs, WASP has been updated with the appropriate overhead rate for each type of work. The system automatically applies the relevant overhead for each labour hour recorded on a job's timesheet, depending on the type of work.
- This is recorded in the financial system as *overhead applied*. As part of the month end process a reconciliation is performed to compare the actual hours worked for each category type and the overheads recovered against the actual overheads incurred. An adjustment is made for any variances.

Network Management costs

- The CAM states that the recovery of this overhead cost pool against the service classifications must be based on total spending on direct costs on each service classification.
- Network management costs are captured under the Network management work category codes, which enables costs incurred in relation to Network Management to be easily extracted.
- As part of the month end process the value of Network Management costs are allocated across the forms of control based on the percentage spend of costs incurred YTD.
- Aurora has automated reports developed within the finance system to extract this data and allocate the costs accordingly.

Network Divisions Corporate and Shared Services costs

- The CAM states that the recovery of this overhead cost pool against the service classifications must be based on total operating spend.
- The Network Division's share of Corporate and Shared Services costs are allocated against work categories that define the expenditure as corporate costs.
- Similar to the process that occurs with the Network Management cost pool, as part of the month end process Network Corporate and Shared Services costs are allocated across the forms of control using the percentage of total operating spend as the driver.
- Aurora has automated reports within the finance system to extract this data and allocate the costs accordingly.

A final review is undertaken at financial year end to ensure the allocation of each cost pool is correct.

Regulatory adjustment (ICAM)

In order to reach the final distribution expenditure for reporting in the RIN, an adjustment is made to the Distribution Business' expenditure as per the Statutory Accounts to account for the final value of corporate costs allocated to the Distribution Business. This adjustment represents the difference between the corporate costs allocated to the Distribution Business in the Statutory Accounts and the actual costs that should have been charged after the final true up is undertaken. In the Statutory Accounts any difference between the budget allocation of ICAM to the Distribution Business and the actual ICAM costs incurred are held in the corporate ledger and not allocated to the Business units. The ICAM adjustment is allocated to the service classifications by applying the same methodology and allocation driver as per the CAM and is reported in the RIN as an adjustment between the statutory accounts and distribution regulated expenditure.

Section 1.5 - Application of negotiated distribution service criteria

As part of its response to the AER's RIN for 2012-13, Aurora is required to document the procedures and processes used to ensure that the negotiated distribution service criteria, as set out in the AER's 2012-17 Distribution Determination[1], have been applied by Aurora when determining prices for negotiated distribution services.

Aurora has only one form of negotiated distribution service during the 2012-17 Regulatory Control Period – the introduction of new public lighting technologies. Aurora did not introduce any new public lighting technologies during the 2012-13 Regulatory Year.

Section 1.6 - Identification of negative change events

When setting the general annual revenue cap which Aurora is allowed to recover from its customers in relation to the provision of distribution network services, the revenue cap for each regulatory year may include a pass through of the unforseen costs, or savings, arising from the occurrence of certain change events that have previously been defined as pass through events by the AER. Negative pass through events are change events that result in Aurora realising savings in the costs of providing direct control services and under Chapter 6 of the National Electricity Rules[2] Aurora is required to submit written notification to the AER of a negative change event within 90 business days of becoming aware of the occurrence of such an event.

Following is a description of the process used by Aurora to identify negative change events and the threshold of materiality applied by Aurora to negative change events.

Aurora undertakes a quarterly review of all budgeted expenditure that is proposed for the relevant financial year. As a component of this review process an assessment is made of all projects that have an intended savings outcome of greater than $3M for both the total operating and capital expenditure related to the project. This saving must be specific to the individual project and is then assessed against the 1 per cent materiality threshold set by the AER for Aurora's distribution determination. Where the project will result in savings greater than the 1 per cent materiality threshold an application for a negative change event may be made to the AER in accordance with the provisions of the NER.

[1] Australian Energy Regulator, AER distribution determination | Aurora 2012–13 to 2016–17 | Negotiating framework and NDSC

[2] Clause 6.6.1(f)

Section 2 - Cost allocation to the regulated distribution business

All costs recorded in Aurora's audited statutory accounts that relate to or are incurred by Aurora in the provision of distribution services must be allocated to Aurora in its capacity as a regulated distribution business, for the purposes of the Regulatory Accounting Statements submitted by Aurora in response to the RIN. There are a number of means by which costs may be allocated to Aurora and paragraphs 2.1 to 2.3 in Schedule 1 of the RIN require Aurora to explain the basis on which costs that were not directly attributable to Aurora have been allocated to Aurora for the 2012-13 Regulatory Year.

Paragraphs 2.1 and 2.2 - Costs allocated to the distribution business on a causal basis

Aurora is required to identify items in its Regulatory Accounting Statements that for the 2012-13 Regulatory Year have been allocated to its distribution business on a causation basis, rather than a directly attributable basis, and explain the basis on which this was done.

Paragraph 2.1(a) - Costs allocated on a causal, rather than direct basis			
Cost item	Paragraph 2.2(a) Amount	Paragraph 2.2(b) Allocation method & rationale	Paragraph 2.2(c) Allocator(s)
People & Culture	$3,694,914	• The costs associated with Aurora's People and Culture Division (which provides recruitment, payroll, safety management and performance management services across the corporation) are allocated to Aurora's Distribution Business on the basis of FTE numbers. • The number of FTEs working in each division was chosen as the allocator for People and Culture costs on the basis that it reflects the amount of effort that the People and Culture Division would reasonably put into providing services to each division and the use of the relevant services by each division.	• The number of FTEs that primarily work for a specific division.
Treasury Operations - Insurance	$1,235,123	• The total cost of insuring Aurora owned buildings, substation assets and buildings, and any minor assets selected for insurance, is allocated to Aurora's Distribution Business on the basis of the percentage of the total insured assets' that are owned by the Distribution Business.	• Insured property asset values.

Paragraph 2.1(a) - Costs allocated on a causal, rather than direct basis			
Cost item	**Paragraph 2.2(a) Amount**	**Paragraph 2.2(b) Allocation method & rationale**	**Paragraph 2.2(c) Allocator(s)**
Accounts Payable	$500,021	• The costs associated with Aurora's centralised accounts payable facility are shared between Aurora's divisions on the basis of the volume of external invoices processed on behalf of each division, as a percentage of the total volume of invoices received from external suppliers. (Internal transactions are excluded on the basis that they are executed by journal entries and do not involve the making of a payment). • The use of invoice volumes was adopted as the most appropriate allocator of these costs. The number of invoices pertaining to each division is also able to be reliably identified without incurring undue cost, using Aurora's existing financial and transactional systems.	• Number of invoices over 12 months requiring payment of an external party.
Information Management	$636,821	• The costs associated with the provision of Aurora's electronic document management system and physical document management function are allocated to the Distribution Business based on the number of personal computers in use within the Division, as a proportion of the total number of PCs in use throughout the organisation. • When developing Aurora's ICAM, it was considered that there is a strong causal link between the number of PCs in service within each division and the work load and direct costs associated with the provision of shared document management services, and the number of PCs also reflects the size and cost of the storage environment required to service each division.	• Number of PCs.
Information Technology	$15,597,755	• The number of PCs in use within each division reflects the strong causal link between the number of Aurora people who use PCs and the work load and direct cost to deliver information technology to the business.	• Number of PCs.
Facilities Management	$5,684,746	• The costs of operating and managing all owned and leased sites occupied by Aurora employees is allocated between Aurora's divisions on the basis of the floor space occupied by each division, as a percentage of the total. • Floor space was selected because it was held to reflect the level of resources and effort applied to property management.	• Occupied floor space.

Paragraph 2.1(a) - Costs allocated on a causal, rather than direct basis			
Cost item	**Paragraph 2.2(a) Amount**	**Paragraph 2.2(b) Allocation method & rationale**	**Paragraph 2.2(c) Allocator(s)**
Contracts	$1,014,681	• Under Aurora's approved ICAM, the cost associated with providing centralised contract administration services is allocated between Aurora's Divisions on the basis of the dollar value of the contracts entered into by each division, relative to the total value of contracts entered into by the business as a whole. • The monetary value of the contracts entered into by each division is considered to be reflective of the overall volume of contracts, their complexity and the corresponding resource effort involved in establishing, maintaining and finalising contracts for each division and subsidiary. The contracts entered into by each division and their value are also able to sourced from Aurora's financial systems, enabling the allocator for this cost item to be developed reliably and cost effectively.	• Dollar value of contracts.
Procurement	$341,741	• The costs associated with the management and delivery of Aurora's procurement processes are shared between divisions on the basis of the dollar value of the procurement contracts entered into by each division (during the course of a year), as a proportion of the total value of procurement contracts . • The value of procurement contracts is taken to reflect the overall volume of purchasing undertaken by each division, on the basis that all goods and services are purchased through contracts with suppliers.	• Dollar value of procurement contracts.

Paragraphs 2.1 and 2.3 - Costs allocated to the distribution business (other than on a causal or direct)

Aurora is required to identify those items in its Regulatory Accounting Statements for the 2012-13 Regulatory Year that were not allocated to its distribution business on a direct basis, and were also unable to be allocated on a causation basis. For each item identified, Aurora is required to explain the reasons why causal allocation could not be applied, indicate the materiality of the amount in question, and the means by which the cost was actually allocated.

Paragraph 2.1(b) - Costs allocated other than on a causal or direct basis				
Cost item	**Paragraph 2.3(a) Amount**	**Paragraph 2.3(b) Materiality**	**Paragraph 2.2(c) Allocation method & rationale**	**Paragraph 2.2(d) Reasons for non-causal allocation**
Office of the CEO	$3,013,842	• Office of the CEO costs are deemed to be material on the basis that the allocation is greater than 10% of the total ICAM allocation to the Distribution Business.	• The costs associated with centralised management and the provision of administrative support for the CEO and the Aurora Board of Directors are allocated between divisions on the basis of the weighted average of the total cost allocations that have a causal driver. • This allocator is used because it reflects the strategic business management focus of the CEO and the Board on each division.	• While shared services costs are allocated between divisions using causal cost drivers, reflecting the generally variable nature of these costs, corporate costs are allocated using non-causal cost drivers because of the generally fixed nature of these costs, and the fact that they tend to be driven by corporate governance requirements rather than business activity. • A review of Aurora's Corporate and Shared Services Cost Allocation by Deloitte in 2010 found that the weighted average of the total cost allocations that have a causality driver is an effective non-causal allocator of corporate costs because it leverages causal allocators and is based on sound causal data, which is in turn underpinned by reliable and objective data sources.

Paragraph 2.1(b) - Costs allocated other than on a causal or direct basis				
Audit & Risk	$700,169	• Audit and risk costs are deemed to be immaterial on the basis that they represent less than 10% of the total ICAM allocation to the Distribution Business.	• The costs associated with Aurora's centralised audit and risk management functions are allocated between divisions on the basis of the weighted average of the total cost allocations that have a causal driver. • This allocator is used because audit and risk related costs are largely determined by corporate governance requirements and it is difficult to find a driver with strong causality for this type of cost.	• Corporate costs are typically allocated using non-causal cost drivers because of the generally fixed nature of these costs, and the fact that they tend to be driven by corporate governance requirements. • The use of the weighted average of the total cost allocations that have a causality driver leverages those causal allocators and is based on sound causal data, which is in turn underpinned by reliable and objective data sources.
Group Finance and Corporate Affairs	$2,747,040	• Group finance and corporate affairs costs are deemed to be immaterial on the basis that they represent less than 10% of the total ICAM allocation to the Distribution Business.	• The costs associated with provision of strategic financial advice, financial compliance processes and business analysis across the organisation are allocated between divisions on the basis of the weighted average of the total cost allocations that have a causal driver. • This allocator is used because, as noted in the approved ICAM, it reflects the relationship with the major internal clients of the CFO, the CEO and the Board.	• Corporate costs are typically allocated using non-causal cost drivers because of the generally fixed nature of these costs, and the fact that they tend to be driven by corporate governance requirements. • The use of the weighted average of the total cost allocations that have a causality driver leverages those causal allocators and is based on sound causal data, which is in turn underpinned by reliable and objective data sources.

Paragraph 2.1(b) - Costs allocated other than on a causal or direct basis				
Treasury Operations	$1,121,947	• Treasury operating costs are deemed to be immaterial on the basis that they represent less than 10% of the total ICAM allocation to the Distribution Business.	• The costs associated with Aurora's treasury operations are allocated between divisions on the basis of the weighted average of the total cost allocations that have a causal driver. • As noted in the approved ICAM, the use of this allocator reflects the relationship with the major internal clients of the CFO, the CEO and the Board.	• While shared services costs are allocated between divisions using causal cost drivers, reflecting the generally variable nature of these costs, corporate costs are allocated using non-causal cost drivers because of the generally fixed nature of these costs, and the fact that they tend to be driven by corporate governance requirements rather than business activity.
Legal Services	$956,584	• The cost of legal services is deemed to be immaterial on the basis that it represents less than 10% of the total ICAM allocation to the Distribution Business.	• The weighted average of the total cost allocations with a causal driver is used to share legal services costs between divisions on the basis that there is no identified causal relationship between the costs associated with the provision of legal services, primarily labour, and the divisions.	• Legal services costs have been allocated using non-causal cost drivers because of the generally fixed nature of these costs, and the fact that they tend to be driven by corporate governance requirements rather than business activity.
Strategy and Corporate Affairs	$2,580,318	• Strategy and corporate affairs costs are deemed to be immaterial on the basis that they represent less than 10% of the total ICAM allocation to the Distribution Business.	• The costs associated with developing business strategy, market monitoring, policy development and public affairs and external relationship management is shared between Aurora's divisions on the basis of the weighted average of the total cost allocations that have a causal driver.	• Strategy and corporate affairs costs have been allocated using non-causal cost drivers because of the generally fixed nature of these costs, and the fact that they tend to be driven by corporate governance requirements.

Section 3 - Cost allocation to service segments

All costs relating to or incurred in the provision of distribution services and allocated to Aurora's distribution business are required to be allocated to a service segment[3]. All costs allocated from the distribution business to a service segment must be allocated in accordance with the cost allocation methodology approved for Aurora by the AER. There are a number of means by which costs may be allocated to service segments and Items 3.1 to 3.3 in Schedule 1 of the RIN require Aurora to explain the basis on which costs that were not directly attributable to a service segment(s) have been allocated between service segments for the 2012-13 Regulatory Year.

Paragraphs 3.1 and 3.2 - Distribution costs allocated to service segments on a causal basis

Aurora is required to identify any items in its Regulatory Accounting Statements for the 2012-13 Regulatory Year that have been allocated from its distribution business to a service segment on a causation basis, rather than a directly attributable basis, and explain the basis on which this was done.

Paragraph 3.1(a) - Costs allocated to service segment on a causal, rather than direct basis			
Cost item	**Paragraph 3.2(a) Amount ($'000)**	**Paragraph 3.2(b) Allocation method & rationale**	**Paragraph 3.2(c) Allocator(s)**
Network Services Management Overheads **(Opex and external costs)**	$19,267	• The Network Services management overheads cost pool is allocated between distribution services classifications on a pro-rata basis, based on the direct labour hours worked in relation to each service segment as a proportion of total program of work direct labour hours, sourced from Aurora's POW.	• Direct labour hours are sourced from the POW.

[3] standard control services, alternative control services, negotiated distribution services and unregulated distribution services

Paragraph 3.1(a) - Costs allocated to service segment on a causal, rather than direct basis			
Cost item	**Paragraph 3.2(a) Amount ($'000)**	**Paragraph 3.2(b) Allocation method & rationale**	**Paragraph 3.2(c) Allocator(s)**
Network Divisional Management (Opex)	$26,711 (excludes Capitalised Labour costs of $7,973)	• Divisional management costs are allocated to service segments on the basis of the total direct spending (Capex and Opex) and other overheads applying to each service segment. • Network management costs include costs incurred in planning, operating and monitoring the distribution network, delivering Aurora's capital program, providing market services (including meter services) and data management, as well as the costs associated with the regulatory and financial management of regulated and unregulated distribution services.	• Uncapitalised Network management labour and other Network management costs are allocated on the basis of total spend (Capex and Opex) of direct and other overheads.
Network Division Corporate & Shared Service Costs (Opex) - ICAM	$9,354 (excludes costs allocated on a non-causal basis of $3,894 which are included in Paragraph 3.1(b))	• Network Division's Corporate & Shared Services primarily sustain the Board and operation of the company's management framework, through contributing to the direction of Aurora and providing appropriate governance to support Aurora's purpose. • Corporate & Shared Services Costs are allocated on a causal basis unless a causal relationship cannot be established without undue cost and effort. Aurora's approved ICAM is used to allocate corporate and shared services costs.	• Allocated on the basis of total direct opex. • ICAM costs have been allocated to the Distribution Business in accordance with the approved ICAM.

Paragraph 3.1(a) - Costs allocated to service segment on a causal, rather than direct basis			
Cost item	**Paragraph 3.2(a) Amount ($'000)**	**Paragraph 3.2(b) Allocation method & rationale**	**Paragraph 3.2(c) Allocator(s)**
Network Services Divisions Management Cost - Corporate & Shared Services - (Capex portion)	$10,891 (excludes Corporate and Shared Services costs of $3,771 allocated on a non-causal basis and included in table below)	• Network Services' portion of Corporate and shared services have been allocated to capex work categories based on the proportion of total capital direct labour hours to total direct labour hours.	• Allocated on the basis of direct labour hours.

The items in table 3.1(a) have been allocated in accordance with the CAM.

Values in table 3.1(a) reconcile to Table 15 Overheads allocation (Regulatory Accounting Statements).

Paragraphs 3.1 and 3.3 - Distribution costs allocated to service segments (other than direct or causal)

Aurora is required to identify any items in its Regulatory Accounting Statements for the 2012-13 Regulatory Year that were not allocated from its distribution business to a service segment on a direct basis, and were also unable to be allocated on a causation basis. For each item identified, Aurora is required to explain the reasons why causal allocation could not be applied, the materiality of the amount in question, and the means by which the cost was actually allocated to a service segment.

Paragraph 3.1(b) - Costs allocated to service segments other than on a causal or direct basis				
Cost item	**Paragraph 3.3(a) Amount ($'000)**	**Paragraph 3.3(b) Materiality**	**Paragraph 3.3(c) Allocation method & rationale**	**Paragraph 3.3(d) Reasons for non-causal allocation**
Network Management Labour (Capex)	$7,973	• Costs are deemed to be material on the basis that the allocation is greater than 10% of the total allocation.	• Allocated based on managerial estimates of the capital percentage allocation of each of FTE/group.	• Allocated based on percentage spend (capital).
ICAM (weighted average) Network services portion	$3,771	• Costs are deemed to be material on the basis that the allocation is greater than 10% of the total allocation.	• Items allocated on non-casual basis to the Distribution business include OCEO, audit and risk, group finance, non-insurance part of treasury, legal and strategy and corporate affairs.	• Allocated based on weighted average method.
ICAM (weighted average) Network Divisional Management portion	$3,894	• Costs are deemed to be material on the basis that the allocation is greater than 10% of the total allocation.	• Items allocated on non-casual basis to the Distribution Business include OCEO, audit and risk, group finance, non-insurance part of treasury, legal and strategy & corporate affairs.	• Allocated based on weighted average method.

Section 4 - Related party transactions

Aurora is required by the AER to identify any related party with which a transaction was conducted during the 2012-13 Regulatory Year. The AER has defined a related entity as another entity that at any time during the 2012-13 Regulatory Year:

- had or, would be expected to have had, control or significant influence over Aurora; or
- was, or would be expected to have been subject to control or significance by Aurora; or
- which was controlled or significantly influenced by another entity that also controlled Aurora.

Related entities do not include financial institutions, authorised trustees corporations, fund managers, trade unions, statutory authorities, government departments or local governments.

Aurora is also required to identify and detail any transactions between Aurora and related entities that relate to the provision of standard control services, alternative control services or negotiated distribution services, where the amount of a transaction is greater than five per cent of the relevant expenditure or revenue category.

Aurora Energy did not conduct any transactions with a related party during the 2012/13 regulatory year.

Aurora does not consider the Hydro-Electric Corporation or Transend Networks Pty Ltd to be related parties.

Section 5 - Efficiency Benefit Sharing Scheme

The purpose of the Efficiency Benefit Sharing Scheme (EBSS) established by the AER is to provide for the sharing between Aurora and distribution network users of any efficiency gains derived by Aurora as a result of its controllable operating expenditure during a given regulatory control period being less than the forecast originally accepted by the AER. The EBSS also allows for the sharing of any efficiency losses incurred by Aurora's as a result of its controllable operating expenditure being more than forecast. As an incentive to reduce operating expenditure, under the EBSS Aurora is able to retain efficiency gains for five years before passing them on to consumers.

Paragraph 5.1 - Capitalisation policy changes

Under the framework and approach paper for the EBSS[4], in order to ensure consistency with actual operating expenditure amounts[5], the AER will adjust the forecast operating expenditure amounts used to calculate 'carryovers' (i.e. the efficiency gains or losses to be carried over between regulatory years) in the event that Aurora changes its capitalisation policies during the current regulatory control period. As part of its annual RIN reporting process, Aurora is required to identify all changes between the capitalisation policy for the relevant regulatory year and the policy applying in the previous regulatory year, state the reasons for the changes and detail the quantum of any impacts that the change in policy has had on forecast and actual operating expenditure.

There were no changes in the capitalisation policy between the previous regulatory year (2011/12) and the current regulatory year (2012/13).

The capitalisation policy is provided in Appendix A.

4 Australian Energy Regulator, *Framework and approach paper*, November 2010.

5 Australian Energy Regulator, *Electricity distribution network service providers: Efficiency Benefit Sharing Scheme*, 26 June 2008, p. 6 (AER, *Electricity DNSPs: EBSS*, 26 June 2008).

Section 6 - Demand Management Incentive Scheme

Under the AER's Demand Management Incentive Scheme (DMIS)[6], in addition to the general annual revenue cap which Aurora is allowed to recover from customers in return for the provision of Tasmania's distribution network and network connection services, Aurora is permitted to recover a fixed amount of additional revenue – the Demand Management Innovation Allowance (DMIA) – as a contribution towards the cost of implementing non-network alternatives to network augmentation, or measures that shift or reduce the demand from customers for network and/or connection services.

As part of its response to the AER's RIN for 2012-13, Aurora is required to report any expenditure on demand management measures undertaken under the DMIS, and demonstrate how each project or program complies with the DMIA criteria[7] set out in the DMIS. This information will form the basis of the AER's assessment of Aurora's compliance with the DMIA criteria, and its entitlement to recover expenditure on those demand management initiatives under the DMIS.

Paragraph 6.1(a) - Provide an explanation of each demand management project or program for which approval is sought

1. **Modelling the amount of load associated with uncontrolled domestic hot water heating that may be shifted using Direct Load Control**

   - The contribution of uncontrolled electric domestic water heating to network peak demand in Tasmania is significant, ranging from 19 per cent – 30 per cent on weekday mornings and 16 per cent – 19 per cent on weekday evenings, as a percentage of the total domestic load.
   - The purpose of this project is the development of a *Hot Water Demand Evaluation Tool,* in order to provide the capability to accurately model and predict the extent of demand reduction (both by location and demographics) that might be achieved through the control of residential electric storage hot water systems, in order to defer network augmentation.
   - The tool will inform the design of a load management program for domestic hot water systems which achieves the maximum peak demand reductions possible whilst ensuring negligible impact on customer amenity.

2. **Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island**

   - The purpose of this project is to model an integrated non-network solution involving load management, energy storage, static voltage control and backup diesel generation, to address capacity constraints in a specific area of the distribution network (Bruny Island). The integrated solution will also be required to provide the capability to allow connection of renewable energy resources, such as wind and solar generation, to the network.

[6] Australian Energy Regulator, Demand Management Incentive Scheme (Aurora Energy) for the Regulatory control period commencing 1 July 2012, October 2010

[7] Australian Energy Regulator, Demand Management Incentive Scheme (Aurora Energy) for the Regulatory control period commencing 1 July 2012, Section 3.1.3, October 2010

3. **Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network**

    - This project entails the execution of a state-wide commercial and industrial (C&I) load survey to identify the characteristics of the principal C&I customers (and customer groups) connected to the distribution network. The survey will also identify the demand management potential which may be realised by C&I customers. The survey's findings will be used to determine the ultimate scope of the C&I demand management program and the benefits which could be realised from the program.

Section 6.1(b) – Compliance with DMIS section 3.1.3 criteria

Paragraph 6.1(b)(i) – Nature and scope of each demand management project or program

1. **Modelling the amount of load associated with uncontrolled hot water heating that may be shifted using Direct Load Control**

    This project involves three phases:

    - gathering consumption data by consumer class and undertaking technical analysis of domestic hot water heating characteristics;
    - building a model that estimates the expected demand reduction that can be achieved without inconveniencing customers; and
    - verifying performance of the model against consumer data.

2. **Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island**

    - The aim of this project is to develop an understanding of the technical feasibility of using an embedded micro-grid power system solution, utilising energy storage and standby diesel generation, to address network constraints in remote areas.
    - The research addresses issues such as frequency and voltage management (encompassing both operational and control strategies), which become more significant for hybrid micro-grid power systems in remote areas such as Bruny Island. The research also addresses issues including dynamic voltage and frequency control, along with small signal stability (i.e. the ability for the network to maintain synchronism under the occurrence of a disturbance). Consideration is also being given to the potential for increasing large-scale and small-scale solar penetration, and the resultant micro-grid coordination and control capabilities which may be required to manage such issues.

3. **Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network**

    - The scope of this project is to evaluate the total potential reduction in peak demand that could be achieved by engaging with C&I customers in the following categories:
        - commercial buildings that have a building management system (BMS) installed;
        - commercial buildings that have the potential to have a BMS installed; and

- industrial customers with discretionary loads, including an evaluation of the discretion that these customers may have to modify their peak demand.

Paragraph 6.1(b)(ii) – Aims and expectations of each demand management project or program

1. Modelling the amount of load associated with uncontrolled hot water heating that may be shifted using Direct Load Control

- This project seeks to provide an efficient means of assessing investment in broad-based or specific area DLC programs to deliver network augmentation deferral through load curtailment.
- Previous studies have shown that consumer engagement is very sensitive to the information being provided, and this project aims to provide factual, independently assessed, information in relation to the extent that consumers would be affected by a hot water DLC program.

2. Research and modelling of the potential for battery storage & embedded generation to address a network constraint on Bruny Island

The aim of this project is to model and optimise the operation of the following new systems on the island:

- An energy storage system (battery).
- An embedded diesel generator.
- Future demand side management capabilities (both residential and commercial).
- Potential for future solar generation of between 200 kW and 1,000 kW in size.
- Potential for future wind generation of between 200 kW and 1,000 kW in size.

Operational scenarios need to be developed to leverage the capabilities of these systems in order to effectively manage the island in the following modes:

- ***Import Mode:*** where the island is importing power from mainland Tasmania (system normal);
- ***Constrained Supply Mode:*** where one submarine cable is out of service;
- ***Islanded Mode:*** where no supply from the mainland is available to the island;
- ***Export Mode:*** where the island is exporting power to mainland Tasmania. This scenario could occur under a network support arrangement where any embedded or renewable generators on Bruny Island could assist in reducing existing constraints on the local distribution and transmission networks.

3. Audit of the scope for peak demand reduction amongst commercial and industrial sector customers connected to the distribution network

The aim of the project is to assist in the creation of a cost effective demand management program to:

- contract significant load reductions from C&I customers, as required; and

- contract the utilisation of embedded/standby generation owned by C&I customers for network support, as required.

Paragraph 6.1(b)(iii) – Process by which each demand management project or program was selected, including the business case for the demand management project and consideration of any alternatives.

1. Modelling the amount of load associated with uncontrolled hot water heating that may be shifted using Direct Load Control

- This project came about through a lack of certainty within the Distribution Business about the demand reduction that might be achieved through the DLC of the large number of domestic electric hot water heating systems that are connected to the uncontrolled energy tariff.
- To formulate a business case for the implementation of a DLC program for domestic hot water systems, the potential load reduction that might be achieved needs to be quantified. This includes assessment of both the level of the reduction in peak demand that is technically possible using DLC and, as part of a separate project, an assessment of the likely level of take-up by consumers.
- Options considered included:
  - using existing industry 'norms' for assessment, many of which are based on summer based peak demand, and accept the resultant uncertainty; and
  - presume the level of control that customers would accept and risk consequent consumer dissatisfaction and disengagement.

2. Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island

- To address constraints imposed by growing demand on Bruny Island and the need to replace ageing infrastructure, Aurora is investigating alternatives to replacement of one of the submarine cables serving the island.
- Aurora has undertaken some preliminary research and evaluation of alternative non-network solutions and has concluded that, with the peak demand periods only occurring for a short period per year, the installation of embedded generation to initially manage the risk of ageing asset failure and defer the replacement of a submarine cable is significantly more cost effective than the other alternatives under consideration.
- Uncertainty does exist regarding whether long term solutions to utilise non-network options, instead of eventual submarine cable replacement, are technically and financially feasible. This project looks at assessing the technical feasibility of the proposed non-network solutions.

3. Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network

- C&I customers make a significant contribution to system peak demand.
- Aurora currently lacks adequate information to develop a comprehensive C&I demand reduction program that takes into account:

- o linkages to the technical trial of a Demand Response System for buildings with a BMS; and
- o the factors that motivate C&I customers to participate in Demand Management programs and commit to managing their loads in response to notifications, and/or their willingness – with appropriate incentives – to accept Demand Management Control of their electrical loads.

Paragraph 6.1(b)(iv) – How each demand management project or program was/is to be implemented

1. **Modelling the amount of load associated with uncontrolled hot water heating that may be shifted though Direct Load Control**
   - The project has been implemented through a collaborative research project with the University of Tasmania.
2. **Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island**
   - The project has been implemented through a collaborative research project with the University of Tasmania.
3. **Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network**
   - This project is being implemented with the assistance of an external service provider to undertake customer audits and evaluate findings.

Paragraph 6.1(b)(v) – Implementation costs of the demand management project or program

1. **Modelling the amount of load associated with uncontrolled hot water heating that may be shifted though Direct Load Control**
   - This project was undertaken in 2012-13, with a total budget allocation of $100,000 (excluding GST).
2. **Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island**
   - This project is scheduled to be undertaken in 2012-14, with a total budget allocation of $100,000 (excluding GST).
3. **Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network**
   - This project is scheduled to run from May 2013 until December 2013, with a budgeted total cost of $180,000 (excluding GST).

Paragraph 6.1(b)(vi) – any identifiable benefits that have arisen from the demand management project or program, including any off peak or peak demand reductions

1. **Modelling the amount of load associated with uncontrolled hot water heating that may be shifted though Direct Load Control**

   - The level of available demand reduction available through the DLC of domestic hot water heating has been identified (for all areas across the state). The results of this analysis are being fed into an economic evaluation of associated DLC programs.

2. **Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island**

   - Demand has been successfully capped to within the nominal rating of the existing submarine cable during the Easter 2013 peak load period using a non-network solution.

3. **Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network**

   - The audit has not yet been completed, so there are no firm results to report at this time.

Paragraph 6.1(c) - Provide and overview of developments in relation to the demand management projects or programs completed in previous years (and any results to date).

- There have not been any demand management programs undertaken or completed in previous years.

Paragraph 6.1(d) - The costs associated with each demand management project or program identified in 6.1(a) are not:

- recoverable under any other jurisdictional incentive scheme;
- recoverable under any other Commonwealth/State Government Scheme;
- included as part of:
  - forecast capital expenditure or forecast operating expenditure; or
  - any other incentive scheme applied by the 2012-17 Distribution Determination.

Paragraph 6.1(e) – Provide the total amount of the Demand Management Innovation Allowance spent in the Current Regulatory Control Period, and how this amount has been calculated

The total expenditure in the Current Regulatory Period against the Demand Management Innovation Allowance is $137,117.

1. **Modelling the amount of load associated with uncontrolled hot water heating that may be shifted though Direct Load Control**

   - Budgeted opex cost for this project is $100,000.
   - Actual costs incurred for 2012-13 are $71,061.
   - Final project costs of $20,000 have been invoiced in 2013/14.

2. Research and modelling of the potential for battery storage and embedded generation to address a network constraint on Bruny Island

- Budgeted opex cost for this project is $100,000.
- Actual costs incurred for 2012-13 were $40,000.

3. Audit of the scope for peak demand reduction amongst commercial and industrial customers connected to the distribution network

- Budgeted opex cost for this project is $180,000.
- Actual costs incurred for 2012-13 were $26,056.

Section 7 - Asset replacement volumes

As part of its response to paragraph 1.1(b), Aurora is required to report the volume of distribution network assets replaced during 2012-13. The following table identifies, for each type of asset, the proportion of those replacements that were like-for-like replacements, where the new asset provided an equivalent level of service to the asset which it replaced. If the proportion of like-for-like replacements has been estimated, details of the basis for estimation are provided.

In identifying the proportion of assets that have been replaced on a like-for-like basis, Aurora has relied on the principle articulated in paragraph 7.1 of Schedule 1, which defines like-for-like replacement as having occurred when a new asset provides an equivalent level of service to the asset which it replaces.

For example, the replacement of a natural wood pole with a pressure impregnated pole has been treated as being an example of like-for-like replacement, despite their differing replacement lives, as has the replacement of Concentric Neutral Solid Aluminium Conductors (CONSAC) with XLPE four core cables, and the replacement of transformers with capacities that are less than the minimum size of transformer now specified by Aurora with larger capacity units.

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Poles			
Concrete	0	0	
Steel & Conc	51	100	
Steel- Lattice	3	100	
Steel-Other	18	100	
Steel-Rail/RSJ	2	0	
Tower-Steel Lattice	3	0	
Wood (Natural) - Not Staked	133	100	
Wood (Natural) - Staked	1	100	

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Wood (CCA) - Not Staked	878	100	
Wood (CCA) - staked	17	100	
Pole-top structures			
Single pole mounted Tx 5<= Tx < 50 kVA	31	100	
Single pole mounted Tx 50<= Tx < 200 kVA	24	100	
Single pole mounted Tx >= 200 kVA	5	100	
Single pole mounted Tx SWER 5<= Tx <25 kVA	0		
Single pole mounted Tx SWER 25<= Tx <= 50 kVA	0		
Galvanised - Single pole mounted Tx 5<= Tx < 50 kVA	43	100	
Galvanised - Single pole mounted Tx 50<= Tx < 200 kVA	36	100	
Galvanised - Single pole mounted Tx >= 200 kVA	10	100	
Galvanised - Single pole mounted Tx SWER 5<= Tx <25 kVA	0		
Galvanised - Single pole mounted Tx SWER 25<= Tx <= 50 kVA	0		
HV Transformers (SWER Isolating & Step)	0		
Galvanised HV Transformers (SWER Isolating & Step)	0		
Conductors			
Steel 3/2.75 GI - Inland (km)	3	100	

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Steel 3/2.75 GI - Near Coast (km)	8	100	
Copper (km)	13	100	
ACSR (km)	0		
AAC (km)	0		
AAAC (km)	0		
HVABC (km)	0		
LV Bare (material unknown)	0		
LVABC	0		
Overhead Services	9	100	
OH System Switchgear			
Recloser/Sectionaliser/LBS - Control Cubicle	0		
Reclosers - N27 Pole Mounted Tank	0		
Sectionaliser/LBS - RL27 Pole Mounted Tank	0		
HV Disconnectors - ABS	75	100	
HV Disconnectors - Links	32	20	Links replaced with ABS mostly
HV Fuse	20	100	
LV Disconnector Fuse	120	100	

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Regulators			
Three Phase Regulators	0		
Single Phase Regulators (Pole Mounted)	0		
Single Phase Regulators (Ground Mounted)	0		
Underground cables			
HV Sub transmission Cables (Oil Filled)	0		
HV Sub transmission Cables (Others)	0		
HV Cable (Oil Draining)	0		
HV Cable (MIND)	0		
HV Cable (Submarine)	0		
HV Cable (XLPE)	0		
HV Cable (XLPE - TR)	0		
LV Cable (Oil Draining)	0		
LV Cable (MIND)	0	100	
LV Cable (CONSAC)	1,500	100	
LV Cable (XLPE)	0		
HV Terminations (Cast Iron Potheads)	12	100	

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
HV Terminations (Heat Shrink)	6	100	
LV Terminations	12	100	
Services (inc. LV pillars & LV service pits)			
LV Furniture - Cabinet	0		
LV Furniture - Turret	0		
Distribution transformers			
Padmount/Kiosk (1500 kVA or greater) - Oil filled	0		
Padmount/Kiosk (1500 kVA or greater) - Air or Gas	0		
Padmount/Kiosk (1000 kVA) - Oil filled	0		
Padmount/Kiosk (1000 kVA) - Air or Gas	0		
Padmount/Kiosk (750 kVA) -- Oil filled	0		
Padmount/Kiosk (750 kVA) - Air or Gas	1	100	
Padmount/Kiosk (500 kVA or less) - Oil filled	0		
Padmount/Kiosk (500 kVA or less) - Air or Gas	2	100	
Fence - Transformer (1500 kVA or greater)	0		
Fence - Transformer (750-1200 kVA)	0		
Fence - Transformer (500 kVA or less)	2	100	

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Fence - Infrastructure	0		
Building - Building and infrastructure	1	100	
Building - Transformer (1500 kVA or greater)	1	100	
Building - Transformer (1000 and 1200 kVA)	0		
Building - Transformer (750 kVA)	0		
Building - Transformer (500 kVA or less)	2	100	
Distribution Switchgear			
Fence - Switchgear (oil-filled)	2	100	
Fence - Switchgear (air/gas insulated)	0		
Fence - LV switchgear	0		
Building - Switchgear (oil-filled)	5	100	
Building - Switchgear (air/gas insulated)	0		
Building - LV Switchgear	0		
Switching Station - Oil-filled switchgear	0		
Switching Station - air/gas insulated switchgear	0		
Connection Assets			
Metering Transformers	9	100	

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Zone transformers			
Rural Zone - Transformer (between 1MVA and 2.5MVA)	0		
Rural Zone - Transformer (less than 1MVA)	0		
Urban Zone - Transformer 20/30 MVA	0		
Urban Zone - Transformer 15/22.5MVA	0		
Zone Switchgear			
Rural Zone - Switchgear	0		
Urban Zone - Switchgear (oil-insulated) - 2 transformer sub	0		
Urban Zone - Switchgear (air-insulated) - 2 transformer sub	0		
Urban Zone - Switchgear (oil-insulated) - 3 transformer sub	0		
Urban Zone - Switchgear (air-insulated) - 3 transformer sub	0		
Zone 'other assets'			
Rural Zone - Building and Infrastructure	0		
Urban Zone - Building and Infrastructure	0		
Urban Zone - Batteries	0		
SCADA and protection			
Urban Zone - Protection Systems	0		

Paragraph 7.1 - Like-for-like asset replacement			
Asset Group/Category	**Actual replacement volumes**	**Like-for-like replacements (%)**	**If like-for-like replacements proportion estimated, provide basis for estimation**
Urban Zone - SCADA Systems	0		
Other			

Section 8 - Non-financial performance monitoring information

Paragraph 8.1 - STPIS Reliability

Following is an explanation of any material differences between the target performance measures specified by the AER under the Service Target Performance Incentive Scheme (STIPS)[8] and Aurora's actual performance in 2012-13, as reported in response to paragraph 1.1(b) of Schedule 1.

The supply reliability categories used in the following tables are as defined in the Tasmanian Electricity Code and the performance targets are as per the Australian Energy Regulator's final determination of the SAIDI and SAIFI targets for Aurora's STPIS[9].

STPIS Reliability

Supply reliability category	Component	Target	Actual	Variance	Explanation
Critical infrastructure	SAIFI	0.22	0.16	-0.06	• Compared to the historical average, the critical infrastructure supply reliability category recorded a similar number of outages. • In 2012/13 the outages experienced in the critical infrastructure category were rectified quicker than the historical average.
	SAIDI	20.79	4.64	-16.15	
High density commercial	SAIFI	0.49	0.30	-0.19	• Compared to the historical average, the high density commercial supply reliability category experienced a reduction in the number of outages with no known cause during 2012/13.
	SAIDI	38.34	33.55	-4.79	
Urban	SAIFI	1.04	0.81	-0.23	• Compared to the historical average, the urban supply reliability category experienced a 22% reduction in outages during 2012/13. • There were material reductions in outages caused by weather, vegetation, and outages with unknown causes.
	SAIDI	82.75	62.64	-20.11	

8 Australian Energy Regulator, *Electricity distribution network service providers Service target performance incentive scheme*, November 2009.
9 Australian Energy Regulator, *Final Distribution Determination Aurora Energy Pty Ltd 2012–13 to 2016–17*, Section 12.1.4 Performance targets, April 2012.

STPIS Reliability					
Supply reliability category	**Component**	**Target**	**Actual**	**Variance**	**Explanation**
High density rural	SAIFI	2.79	2.13	-0.66	• Compared to the historical average, customers in high density rural areas experienced a 5% reduction in outages during 2012/13. • There were reductions in outages caused by weather, vegetation, asset failures and a reduction in outages where the cause was unknown.
	SAIDI	259.48	191.19	-68.29	
Low density rural	SAIFI	3.20	2.90	-0.30	• Compared to the historical average, the low density rural supply reliability category experienced an 8% reduction in outages during 2012/13. • There were material reductions in outages caused by weather and asset failures.
	SAIDI	333.16	337.60	+4.44	

Customer Service - Telephone answering

For the first three years of the current regulatory period, the performance target set by the AER in relation to Aurora's telephone answering requires 73.6 per cent of calls to be answered within 30 seconds.

Telephone answering				
	Target	**Actual**	**Variance**	**Explanation**
Percentage of calls answered within 30 seconds	73.6%	83.3%	-9.7%	• The percentage of calls answered by the Aurora Fault Centre within 30 seconds exceeded the target due to process changes that improved the flow of fault information and fault emergency calls. • 2011/12 calls volumes increased by approximately 4% during 2012/13.

Section 9 - Reconciliation of regulated asset base

Aurora is required to provide information that reconciles:

- the incremental change that occurred between the 2011-12 and 2012-13 Regulatory Years in the closing value of property, plant and equipment, as recorded in Aurora's audited statutory accounts; and
- the incremental change in the closing value of Aurora's regulatory asset base which occurred between the 2011-12 and 2012-13 Regulatory Years.

Property, Plant and Equipment

Paragraph 9.1(a) - Audited Statutory Accounts							
Property, Plant and Equipment	**2011-12** $'000 nominal	**Asset Revaluation/CPI Adjustments** $'000 nominal	**2012-13** Additions $'000 nominal	**2012-13** Depreciation $'000	**2012-13** Customer Contributions/Disposals $'000	**2012-13** Other Adjustment $'000	**2012-13** $'000 nominal
Closing balance as per Aurora's statutory accounts (Distribution Business allocated)	1,436,269	(8,257)	106,175	(91,317)	(3,839)	1,201	1,440,233
Standard control services[10]	1,298,952	21,173	99,258	82,999	(11,886)	(2,006)	1,322,491

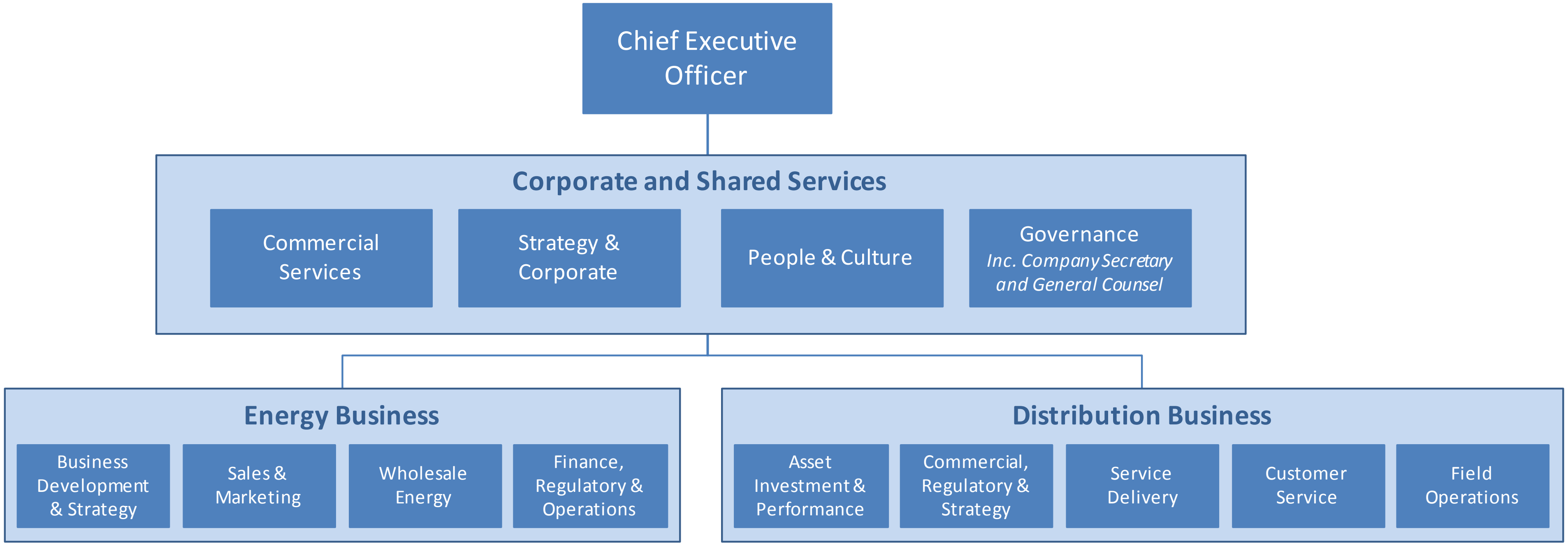
[10] May not sum due to rounding

Section 10 - Charts

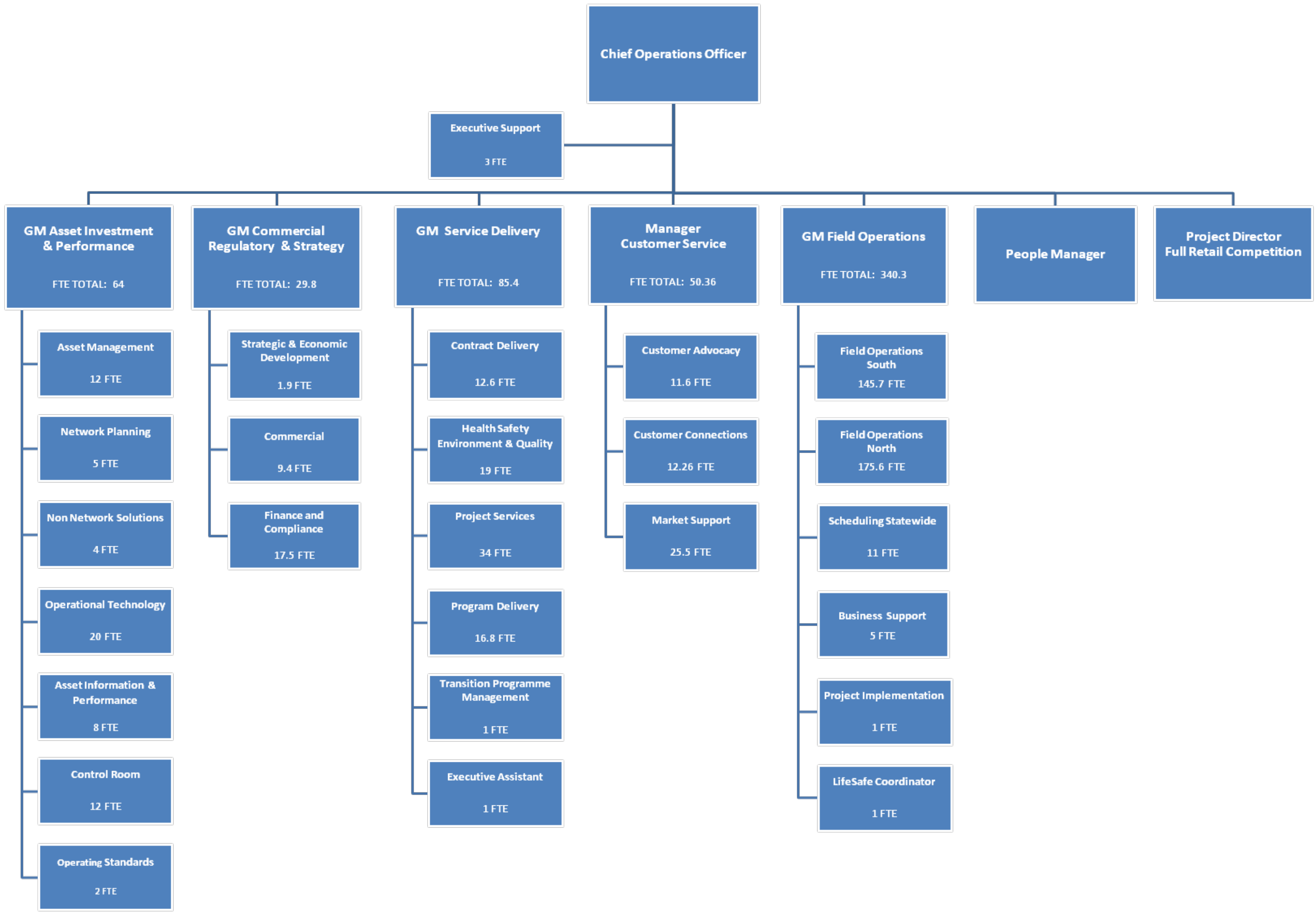
As part of its response to the AER's Regulatory Information Notice, Aurora is required to provide charts setting out:

- the group corporate structure of which Aurora is a part; and
- Aurora's organisational structure.

Paragraph 10.1(a) – Aurora Energy Group structure (at 30 June 2013)



Paragraph 10.1(b) – Distribution Business organisational structure (at 30 June 2013)



Section 11 - Audit reports

Paragraph 11.1(a) - Special purpose financial report

Tasmanian
Audit Office

Independent Auditor's Report

To the Members of Aurora Energy Pty Ltd

I have audited the accompanying special purpose financial report of Aurora Energy Pty Ltd ("the Company"), which comprises the Regulatory Information Notice Financial Template for the year ended 30 June 2013.

In accordance with section 28M(e) of the National Electricity (Tasmania) Law, the forecast information, explanations relating to material differences and step change expenditure included in the Regulatory Information Notice Financial Template has not been audited.

Directors' Responsibility for the Regulatory Information Notice Financial Template

The Directors of the Company are responsible for the preparation of the Regulatory Information Notice Financial Template and have determined that the basis of preparation described in the Regulatory Information Notice is appropriate to meet the reporting requirements of the Australian Energy Regulator and to meet the needs of the members. The Directors are also responsible for such controls as they determine are necessary to enable the preparation of the Regulatory Information Notice Financial Template that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on the Regulatory Information Notice Financial Template based on my audit. I conducted my audit in accordance with Australian Auditing Standards. Those standards require that I comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance about whether the Regulatory Information Notice Financial Template is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Regulatory Information Notice Financial Template. The procedures selected depend on my judgment, including the assessment of the risks of material misstatement of the Regulatory Information Notice Financial Template, whether due to fraud or error. In making those risk assessments, I consider internal controls relevant to the entity's preparation and fair presentation of the Regulatory Information Notice Financial Template 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 Company's internal controls. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by the Directors in the 30 June 2013 financial report of the Company used as a basis for completion of the Regulatory Information Notice Financial Template, as well as evaluating the overall presentation of the Regulatory Information Notice Financial Template.

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I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Independence

In conducting this audit, I have complied with the independence requirements of Australian Auditing Standards and other relevant ethical requirements.

Opinion

In my opinion the Regulatory Information Notice Financial Template presents fairly, in all material respects, the basis of accounting described in the Aurora Energy Pty Ltd 30 June 2013 financial report and has been prepared in accordance with the relevant requirements of the Regulatory Information Notice.

Restriction on Distribution

Without modifying my opinion, I draw attention to the fact the Regulatory Information Notice Financial Template is prepared to assist the Company to meet the requirements of the Aurora Regulatory Information Notice issued by the Australian Energy Regulator. As a result the Regulatory Information Notice Financial Template may not be suitable for another purpose. My report is intended solely for the Company and the Australian Energy Regulator and should not be distributed to parties other than the Company or the Australian Energy Regulator.

Tasmanian Audit Office

E R De Santi
Deputy Auditor-General
Delegate of the Auditor General

HOBART
2 December 2013

Paragraph 11.1(b) - Audit report for non-financial regulatory information

Tasmanian Audit Office

Independent Assurance Report

To the Members of Aurora Energy Pty Ltd

I have performed assurance procedures on the accompanying the Regulatory Information Notice Non-Financial Template of Aurora Energy Pty Ltd ("the Company") for the year ended 30 June 2013.

In accordance with section 28M(e) of the National Electricity (Tasmania) Law, I have undertaken certain audit procedures (as described below) on the following Regulatory Information Notice Non-Financial Template schedules:

Service Target Performance incentive Scheme:

- Schedule 1a – Reliability
- Schedule 1b – Customer Service
- Schedule 1c – Daily Performance
- Schedule 1d – Major Event Day (MED) Threshold
- Schedule 1e – Exclusions

Demand:

- 2 – Demand

Directors' Responsibility for the Regulatory Information Notice Non-Financial Template

The Directors of the Company are responsible for the preparation of the Regulatory Information Notice Non-Financial Template and have determined that the basis of preparation described in the Regulatory Information Notice is appropriate to meet the reporting requirements of the Australian Energy Regulator and the needs of the members. The Directors are also responsible for such controls as they determine are necessary to enable the preparation of the Regulatory Information Notice Non-Financial Template that is free from material misstatement, whether due to fraud or error.

Assurance Practitioner's Responsibility

My responsibility is to express a conclusion on the Regulatory Information Notice Non-Financial Template based on my procedures. I conducted my procedures in accordance with Standard on Assurance Engagements ASAE 3000 *Assurance Engagements Other than Audits or Reviews of Historical Financial Information*. This standard requires that I comply with relevant ethical requirements relating to limited assurance engagements and plan and perform my work to obtain limited assurance about whether the Regulatory Information Notice Non-Financial Template is free from material misstatement.

A limited assurance engagement involves performing procedures on the amounts and disclosures included in the Regulatory Information Notice Non-Financial Template. Specifically, I have agreed the Regulatory Information Notice Non-Financial Template schedules to non-financial data extracted by Company personnel from relevant Company operating systems. Based on the limitations described below, I do not provide any conclusion on the completeness of the amounts included in the Regulatory Information Notice Non-Financial Template.

Independence

In conducting my procedures, I have complied with the independence requirements of Australian Auditing Standards and other relevant ethical requirements.

Non-Financial Data Provided

In completing my procedures, the following data for the year ended 30 June 2013 was provided to me and used in assessing the accuracy of the non-financial data included in the Regulatory Information Notice Non-Financial Template:

Service Target Performance incentive Scheme:	
Schedule 1a - Reliability	Excel spreadsheets based on planned/unplanned outage data extracts from the "Outage Management System" Customer data from the Geographic Information System and the Spatial Data Warehouse
Schedule 1b – Customer Service	Call centre data summary reports
Schedule 1c - Daily Performance	Excel spreadsheets based on planned/unplanned outage data extracts from the "Outage Management System" Customer data from the Geographic Information System and the Spatial Data Warehouse
Schedule 1d – Major Event Day (MED) Threshold	MED data from the Spatial Data Warehouse
Demand	
2 – Demand	Maximum coincident demand data at the network level System data and related reports by substation and demand type (forecast, actual raw and weather normalised).

My procedures involved undertaking a walkthrough of the systems / process by which non-financial data is captured and reported. Due to the nature of the systems / processes used, I have undertaken a substantive approach to my procedures. These procedures included agreeing the non-financial data in the Regulatory Information Notice Non-Financial Template to the non-financial data described above. Where applicable to support the non-financial data in the Regulatory Information Notice Non-Financial Template, calculations were re-performed using the non-financial data and formulae included in the Regulatory Information Notice Non-Financial template or as provided to me.

Limitations of Non-Financial Data

There are a number of limitations associated with the non-financial data provided and used in assessing the accuracy of the non-financial data included in the Regulatory Information Notice Non-Financial Template:

- I have not assessed the operation of any IT general controls or application specific controls and therefore are unable to conclude on the completeness of the non-financial data;
- I have not undertaken any limited assurance procedures during the year and therefore am unable to conclude on the operation of controls over systems and processes used to generate the non-financial data;
- The Outage Management System is "live" and therefore only point in time data is available for review and use; and
- Source data from the Company's telecommunications systems is not retained by the Company beyond a period of three months and therefore I was unable to assess the accuracy of summary report data provided to me and used in undertaking my procedures.

My conclusion has been formed taking these limitations into account.

Conclusion

Based on the completion of the procedures described in this report over the non-financial data provided to me, nothing has come to my attention that causes me to believe that the non-financial data contained within the Regulatory Information Notice Non-Financial Template, in all material respects, is not fairly stated.

Restriction on Distribution

Without modifying my conclusion, I draw attention to the fact the Regulatory Information Notice Non-Financial Template is prepared to assist the Company to meet the requirements of the Aurora Regulatory Information Notice issued by the Australian Energy Regulator. As a result the Regulatory Information Notice Non-Financial Template may not be suitable for another purpose. My report is intended solely for the Company and the Australian Energy Regulator and should not be distributed to parties other than the Company or the Australian Energy Regulator.

Tasmanian Audit Office

E R De Santi
Deputy Auditor-General
Delegate of the Auditor General

HOBART
2 December 2013

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Section 12 - Board resolution

Aurora Board Resolution

RIN Response – Regulatory Year One 2012/13)

Statutory Declaration

I, Geoffrey Livingstone Willis Confidential do solemnly declare that:

At the November 2013 Aurora Board meeting:

- It was **resolved** that to the best of the Board's information, knowledge and belief the:
  - Information provided in response to paragraph 1.1(a) (being the information to be provided in the workbook attached to Appendix B) is true and fair; and
  - Service target performance incentive scheme, demand and asset installation information provided in response to paragraph 1.1(b) (being the information provided in templates 1(a), 1(b), 1(c), 1(d), 1(e), 1(f), 2 and 7 of the workbook attached at Appendix C) is true and fair.
- The Board **approved** the submission of the RIN response to the AER by the CEO by 13 December 2013.

I make this solemn declaration under the *Oaths Act 2001*.

Declared at: HOBART TASMANIA
(Place)

On: 28 - 11 - 13
(Date)

(Signature)

Before me: JANELLE MARIE O'REILLY
Confidential

~~*(Justice, commissioner for declarations or authorised person)*~~
SOLICITOR ADMITTED TO PRACTISE
IN VIC, NSW & TAS.

Principles and requirements (Appendix A checklist)

In providing the financial information specified in Schedule 1 of the AER's Regulatory Information Notice, Aurora is required to adhere to the principles and requirements set out by the AER in Appendix A of the RIN. The following table records Aurora's general compliance with the requirements of Appendix A.

Principle		Statement of compliance	Supporting information
1.	**General**		
1.1	(a)	Aurora's Regulatory Accounting Statements have been derived from its Audited Statutory Accounts.	• Independent audit opinion.
	(b)	Aurora's Regulatory Accounting Statements may be verified with reference to its Audited Statutory Accounts.	• Independent audit opinion.
	(c)	Aurora's Regulatory Accounting Statements reflect the economic substance of transactions rather than their legal form.	• Independent audit opinion.
	(d)	Aurora's Regulatory Accounting Statements include only costs that have been incurred in or relate to the provision of *standard control services*, *alternative control services*, *negotiated distribution services* and *unregulated distribution services*.	• Aurora's regulatory accounts include only costs that have been incurred in or relate to the provision of distribution services that have been allocated to the Distribution Business as per Aurora's approved ICAM, and to service segments in accordance with Aurora's CAM.
	(e)	Aurora's Regulatory Accounting Statements are presented on a fair and reasonable basis and reflect only those costs, revenues, assets and liabilities that may be reasonably attributed to Aurora Energy.	• Costs, revenue, assets and liabilities have been reported as per Aurora's chart of accounts and agree with Aurora's audited statutory accounts. • Independent audit opinion.
	(f)	In so far as is reasonably practicable, Aurora's Regulatory Accounting Statements have been prepared in accordance with the general rules and format, and use the accounting principles and policies applicable to, the Audited Statutory Accounts, except as otherwise required by the Regulatory Information Notice.	• Independent audit opinion.

Principle		Statement of compliance	Supporting information
	(g)	Aurora's Regulatory Accounting Statements have been presented in an understandable manner, without compromising relevance or reliability.	• Independent audit opinion.
	(h)	Aurora's Regulatory Accounting Statements state fairly the financial position of Aurora Energy as at 30 June 2013.	• Independent audit opinion.
	(i)	Aurora's Regulatory Accounting Statements have not been adjusted for inflation.	• Aurora's expenditure for 2012-13 is reported as incurred and as per Aurora's audited financial statements.
2.	**Cost allocation to the regulated distribution business**		
2.1	All costs in the Audited Statutory Accounts that relate to or have been incurred in the provision of distribution services have been allocated to Aurora Energy in accordance with paragraph 2.3 of Appendix A – Principles and Requirements.		• All costs that relate to or have been incurred in the provision of distribution services have been allocated to Aurora Energy in accordance with paragraph 2.3 of Appendix A. • Audit opinion and audited statutory accounts.
2.2	All costs in the Audited Statutory Accounts that relate to or have been incurred in the provision of distribution services and allocated to Aurora Energy have been allocated to a *standard control service*, *alternative control service*, *negotiated distribution service* or *unregulated distribution service*.		• All costs relating to or incurred in the provision of distribution services have been allocated to categories of distribution services in accordance with Aurora's approved CAM. • Independent audit opinion.
2.3	(a)	All costs allocated to Aurora Energy under requirement 2.1 that are directly attributable to Aurora Energy have been allocated to Aurora Energy.	All costs relating to or incurred in the provision of distribution services that are directly attributable to Aurora's Distribution Business have been allocated in accordance with Aurora's approved ICAM.

Principle	Statement of compliance	Supporting information
(b)	All costs allocated to Aurora Energy under requirement 2.1 that are not directly attributable to Aurora Energy have been allocated to Aurora Energy on a causation basis using an appropriate allocator (determined in accordance with Schedule 1 of the RIN), unless the item is not material.	• All costs relating to or incurred in the provision of distribution services that are not directly attributable to Aurora Energy's distribution business have been allocated in accordance with Aurora's approved ICAM.
(c)	All costs allocated to Aurora Energy under requirement 2.1 that are directly attributable to Aurora but not directly attributable to a *standard control service*, *alternative control service*, *negotiated distribution service* or *unregulated distribution service* have been allocated across distribution services in accordance with the Cost Allocation Method.	• All costs allocated to Aurora's Distribution Business that are directly attributable to the Distribution Business but not a category of distribution service have been allocated to asset categories in accordance with Aurora's approved CAM.
(d)	All costs allocated to Aurora Energy under requirement 2.1 that are directly attributable to Aurora that are fixed asset (costs?) have been allocated to asset categories on a directly attributable or causal basis using appropriate allocators.	• Distribution fixed assets costs have been allocated to Aurora's Distribution Business either directly or on a causation basis in accordance with Aurora's approved ICAM.
(e)	All costs allocated to Aurora Energy under requirement 2.1 that are an operating or maintenance cost have been allocated to a cost category on a directly attributable or causation basis using an appropriate allocator.	• Operating or maintenance costs allocated to a cost category on a directly attributable or causation basis have been allocated using the allocators set out in Aurora's ICAM.
3.	**Cost allocation to service segments**	
3.1	All costs allocated from the distribution business to a service segment have been allocated in accordance with Aurora's approved cost allocation method.	• Costs allocated to service segments have been allocated in accordance with Aurora's approved CAM.

Principle	Statement of compliance	Supporting information
4.	**Capital contributions**	
	Customer capital contributions have been treated by Aurora in accordance with the method approved in the AER's 2012-17 Distribution Determination.	• Capital contributions have been recognised in line with Aurora's Customer Capital Contributions policy.
5.	**Reconciliation of Regulatory Asset Base**	
5.1	The incremental change in Aurora's Regulatory Asset Base has been derived in nominal terms for the purposes of reconciliation with the Audited Statutory Accounts.	• Aurora's Regulatory Asset Base has been reported in nominal terms.
5.2	No asset revaluations or adjustments for impairment have been made that have not been agreed to or required by the AER.	• A metering asset impairment has been reported in Aurora's income statement in order to align the valuation of meters in Aurora's statutory accounts with the value of Aurora's metering assets at 1 July 2012, as determined by AER.
5.3	No asset revaluations or adjustments for impairment made in Aurora's Audited Statutory Accounts have been reflected in Aurora's Regulatory Account Statements.	• In the case of grid assets, Aurora's accounting policies require statutory asset values to align with regulatory asset values. • Therefore asset revaluations and adjustments for impairment made in Aurora's statutory accounts (see metering asset impairment referenced in relation to Principle 5.2) have been reflected in Aurora's regulatory accounts.
5.4	Capital work-in-progress has been allocated to the relevant asset categories and has not been shown as work-in-progress.	• Capital work in progress has been included as part of capital additions based on an "as incurred" methodology.
5.5	All expenditure on capital works has been allocated to an asset category.	• Capital additions have been allocated to asset categories and the value of those additions aligned with Aurora's audited financial statements. • Independent audit opinion.

Principle	Statement of compliance	Supporting information
5.6	Goodwill and any related impairments have not been included in the Regulatory Accounting Statements.	• Goodwill and impairment of assets have not been allocated to Aurora's Distribution Business, and are held by Aurora at the consolidated company level.
6.	**Depreciation**	
6.1	Depreciation charges attributed to Aurora Energy have been attributed to the distribution services that employ the assets to which the charges relate, in accordance with the requirements of Appendix A of the RIN.	• Depreciation has been attributed to the asset class and services to which the assets relate.
6.2	Depreciation charges on assets accounted for within distribution services have been based on economic asset lives.	• Aurora's depreciation schedules for grid assets are as per the asset lives determined in the AER's 2012-17 Distribution Determination for both regulatory and statutory accounting purposes.
7.	**Alternative control services and other activities**	
7.1	Direct and indirect overheads relating to alternative control services or other activities have been allocated in accordance with Aurora's approved cost allocation method.	• Overheads have been allocated to services including, alternative control services, based on Aurora's approved CAM.

Appendix A – Capitalisation Policy

The Aurora Energy Capitalisation Policy for the 2012-13 Regulatory Year

Fixed Assets - Policy

Capitalisation

23 October 2012

Version 3.0

Aurora Energy

DOCUMENT DETAILS

Document title	Fixed Assets – Policy - Capitalisation
Document Version	Version 3.0
Version Date	23 October 2012
Next Review Date	23 October 2013
Document file name	CO-#407411-v5-Fixed_Assets_-_Policy_-_Capitalisation.DOC

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Purpose and Scope

The objective of this policy is to prescribe the accounting treatments for property, plant and equipment. This policy is set up in compliance with accounting standard AASB116 Property, Plant and Equipment and AASB 138 Intangible Assets.

This policy shall apply to the accounting for cost incurred in the replacement, alteration, construction and purchase of plant, property and equipment by Aurora and its subsidiaries.

This policy applies to both capital works (constructed assets) and purchased assets.

This policy should be read in conjunction with the policies referenced in Section 8.

Background

This policy has been developed to specify the capitalisation criteria that expenditure needs to meet in order to qualify as capital and therefore be recognised in the carrying amount of an item of property, plant and equipment.

Definitions

For the purpose of this policy unless otherwise stated the definitions used within this policy are taken to be the same as in AASB Glossary of Defined Terms.

Policy Statements

Asset Recognition

The capitalisation threshold for expenditure on an asset is a value greater than $1,000, unless the asset is covered by the Attractive Assets Policy. All assets that meet this threshold are to be capitalised in accordance with AASB 116 and AASB 138.

An asset should be recognised in the statement of financial position when and only when:

a) It is probable that any future economic benefits associated with the item will flow to or from the entity; and

b) The asset has a cost or value that can be measured with reliability.

Asset Cost

The cost of an item of plant, property and equipment (purchased or constructed) comprises mainly:

- The purchase price;
- Import duties and non refundable taxes (i.e. GST is excluded from the cost);
- Initial delivery and handling cost (including freight);
- Cost of site preparation;

- Installation and assembly cost;
- Professional fees (e.g. design, architectural and engineering);
- Cost of testing to bring the asset into service (this should be net of any proceeds that may be generated from the testing process);
- Borrowing cost capitalised (see below);
- Direct material cost; and
- Systematic allocation of direct labour and overheads attributable to bringing the asset to its working condition. The cost of an internally constructed asset should use the full absorption costing basis. As such overheads attributable to the costs of construction of the asset would be included in the capitalised cost.

In addition to the above, retirement/restoration cost should also be included in the cost of an item of property, plant and equipment to the extent it is recognised as a provision under AASB 137 Provisions, Contingent Liabilities and Contingent Assets. In brief, such cost should be significant, can be accurately measured, specific to the asset and is probable to occur at the end of the service life of the asset.

The following costs may not be capitalised as assets:

- Costs of relocating or reorganising an asset, or entity's operations;
- Costs of opening a new facility, or conducting a business in a new location (including the cost of staff training);
- Costs of introducing a new product, including advertising or promotional costs;
- Administration costs, and general overhead costs including (training, establishing policies and procedures, hiring and redundancy costs);
- Initial operating losses post commercial commissioning; and
- Repairs and maintenance of an asset. Repairs involve the day-to-day servicing and maintenance of an asset and ensure that it is maintained at its full productive capacity, and do not increase the previously estimated useful life. Refer section 6 and examples in Appendix 1.

Initial Spares

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 (capital spares) qualify as property, plant and equipment when it is expected that they will be used for 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.

Capitalised Interest

Borrowing costs, such as interest, are to be capitalised as part of the cost of the asset on all projects when the following conditions are satisfied:

i. The borrowing costs are attributable to the acquisition, construction or production of a qualifying asset as defined under AASB 123; and
ii. The project is funded from external borrowing not internal funds.

The capitalisation of borrowing costs, as part of the cost of a qualifying asset shall commence when:

i. Expenditure for the asset are being incurred;
ii. Borrowing costs are being incurred; and
iii. Activities that are necessary to prepare the asset for its intended use or sale are in progress.

Capitalisation of borrowing costs shall cease when substantially all the activities necessary to prepare the qualifying asset for its intended use or sale are complete.

Where funds are borrowed specifically for a project the amount can be determined by the actual borrowing costs, however where funds are borrowed generally and used for the purpose of obtaining qualifying assets, the rate of interest used as the capitalisation rate is to be equivalent to the weighted average borrowing costs of Aurora.

Discussion of Policy Statements

Repairs v Refurbishment/ Replacement

One of the difficulties of fixed asset accounting is determining whether expenditure on an asset is a repair or refurbishment.

The key difference is that repairs involve day-to-day maintenance of an asset, aimed at restoring the asset to its original working condition. Repairs do not extend the useful life or increase the future economic benefits of an asset. Examples include: regular maintenance checks, replacement of tyres and small parts.

Refurbishments or replacements are expenditure, which increase the estimated useful life of an asset, and provides significant increased future economic benefits through improved quality of output, increased capacity, improved efficiencies or economy of operation. Examples include a major overhaul, replacing the interior of a building, planned replacement of major components of an asset to improve function, office fit-outs or refurbishments and system upgrades.

Cancelled Projects

If at any stage a project does not proceed, or it is deemed that the project will not provide any future economic benefits, as soon as the decision is made that the project has ceased, all the accumulated costs that relate to that project must be expensed to the business area responsible.

Work In Progress

Assets are set up as capital projects in the Navision system via capital jobs. These jobs sit in capital work in progress account until the completion of the job, at which time the cost will be capitalised to asset shells and form part of property plant and equipment on the Balance Sheet. Depreciation commences from the completion date of the job.,

Capital Works Job Review

Operating Business Units are to regularly review their capital jobs sitting in work in progress for completed jobs to ensure they continue to comply with the capitalisation policy, to write off expenditure no longer satisfying criteria for being carried as an asset and transfer completed jobs to asset shells.

Decommission/ Derecognising an Asset

The gain or loss arising from the decommission/derecognising of an asset should be included in profit and loss when the item is derecognised.

The decommissioning cost of an existing asset should not form part of the cost basis of a new asset created to replace it, except were the decommissioning costs are not material and are difficult to separately identify from the installation or construction costs of the new assets.

An example is the replacement of poles and equipment as a result of bushfires. The value associated with the remaining useful life of the assets, which have been replaced, is written off, and does not form part of cost base of the new assets to replace them. The asset which has been replaced must also be written out of the Regulated Asset Base (RAB), at the same time the new asset is introduced to the RAB, otherwise the RAB will be overstated.

Impairment of assets

At each reporting date Aurora is required to review the carrying amount of its assets, and determine whether an indication of impairment exists. This will be undertaken in line with AASB 136 and will be authorised by the CFO.

Intangible Assets

Where there is expenditure incurred in creating an internally generated intangible asset, it needs to be determined whether the expenditure meets the definition of research or development expenditure as defined in AASB 138 Intangible Assets.

Research expenditure is the original planned investigation undertaken with the prospect of gaining new scientific or technical knowledge and shall be expensed to the income statement as incurred.

Development expenditure is the application of research findings to plan or design a product, process, systems or services before the start of commercial production or use. Any costs incurred during the development phase must be expensed unless it can be demonstrated that the criteria in AASB 138 are met.

All expenditure on research and development, regardless of whether capitalised or expensed needs to be identified for each project for taxation purposes.

Administration

Breach of Policy

Significant breaches of this policy will be reported to the GM Group Finance and Shared Services.

Periodic Review of this Policy

This Policy will be reviewed every two years unless circumstances change that require earlier review.

References

- AASB 116 Property, Plant and Equipment
- AASB 138 Intangible Assets
- AASB 137 Provisions, Contingent Liabilities and Contingent Assets
- AASB Glossary of Defined Terms
- Fixed Assets - Policy – Fixed Asset Manual CO#-10209370
- Fixed Assets - Policy - Attractive Assets CO#-10080513
- Fixed Assets - Policy - Minor Fixed Asset Stocktake CO#-10138560

Appendix 1

Examples of capital and operating expenditure

Whether expenditure is capital or operating expense is determined by considering the facts in each case. The following examples are provided to assist with the application of this policy.

Note: Where there is a replacement of an asset, which forms part of our regulated asset base (RAB), the impact on RAB as part of the replacement must be considered to ensure that RAB is not overstated.

Distribution Assets

Unit of Property (UOP)	**Expenditure**	**Capitalisation Criteria**	**Accounting Treatment**
Feeder (overhead)	Repair a wooden pole as a consequence of car accident with either a wooden pole or a concrete pole as being the modern day equivalent	Repair	Operating
	Complete replacement of poles (eg due to car accidents, bush fires, or programmed)	Extend the life of the original asset Note: the asset, which has been replaced, must be written out of RAB, at same time as the new asset introduced to the RAB. Debit income statement with the remaining useful life value of asset that is replaced.	Capital
	Replacing conductor for all HV and LV feeders over 2 spans with larger conductor to increase capacity	Increase in capacity	Capital
	Programmed replacement HV and LV conductors that have reached the end of their serviceable life	Extend the life of the original asset	Capital
	Repairing a transformer (eg. rewiring as part of maintenance program)	Repair	Operating
	All additions and extensions to overhead HV and LV feeders over 2 spans including switchyards	Creates a new asset	Capital

Unit of Property (UOP)	Expenditure	Capitalisation Criteria	Accounting Treatment
	Installing larger capacity transformer and associated equipment	Increase in capacity	Capital
	Installing additional transformer and associated equipment, reclosers, sectionalisers and air break isolators	Creates a new asset	Capital
Feeders (Underground)	Installing additional HV and LV underground cables, including fittings	Creates a new asset	Capital
	Installing HV and LV underground cable to replace overhead line	Creates a new asset	Capital
Substations	To upgrade an existing earth mat due to meet safety requirements	Additional functionality	Capital
	Installing new substation, including HV and LV switchgear, transformers and enclosure	Creates a new asset	Capital

Meter Assets

Unit of Property (UOP)	Expenditure	Capitalisation Criteria	Accounting Treatment
Domestic Residential Meters	Cost of meter and Installation to customer's residence	Creates a new grouped asset	Capital
Demand Meters	Cost of meter and Installation to customer's residence	Creates a new grouped asset	Capital
Domestic Electronic LV Meter (Intelligent metering system)	Cost of meter and Installation to business and key customer's premises	Creates a new grouped asset	Capital
Polyphase 3 phase HV Meter (Intelligent metering	Cost of meter and Installation to business and key customer's premises	Creates a new grouped asset	Capital

Unit of Property (UOP)	Expenditure	Capitalisation Criteria	Accounting Treatment
system)			
Prepayment LV Meter (domestic)	Cost of meter and Installation to customer's residence	Creates a new grouped asset	Capital

Other Assets

Unit of Property (UOP)	Expenditure	Capitalisation Criteria	Accounting Treatment
Minor Corporate Application Systems	Increases in the functionality of a computer system for example, improving the quality of output, speed or security	Additional functionality	Capital
Major IT Projects	Installing new systems eg BIRT reporting/ upgrades and enhancements to current systems eg WASP, Frontline/ Navision.	Searching for possible alternative products/ services.	Operating
		All costs incurred in the development and implementation phases, including project management.	Capital
		Where it becomes evident that it is not probable future economic benefits will eventuate from project	Operating
Facilities/ Property	Refurbishments/ office fit-outs eg workstations/ refurbishment to café area	Creates an asset with separate useful life or increases future economic benefits of existing asset.	Capital
	Upgrades to various Depot locations i.e. truck wash, vehicle shelters/ toilet upgrades etc	Where major works are carried out, which extend useful life, improve functionality or create a new asset	Capital