Category Analysis RIN Basis of Preparation

Template 2.1 Expenditure Summary

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.1 Expenditure Summary of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.1 Expenditure Summary (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.1 Expenditure Summary , Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

Furthermore, the below additional requirement/s were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation. Responses to these requirements are made as attachment/s to this Basis of Preparation.

Table 1: Attachment/s to Basis of Preparation for Template 2.1 Expenditure Summary

Notice Reference	Requirement	Attachments
Appendix E, paragraph 2.4-2.5	▪ Ergon Energy must provide an excel spread sheet that contains the calculation of balancing items reported in Regulatory Template 2.1 ▪ Ergon Energy must provide a reconciliation between the total capital and operating expenditure provided in the Regulatory Template 2.1 to the capital and operating expenditure recorded in Ergon Energy's Regulatory Accounting Statements and Audited Statutory Accounts. ▪ Ergon Energy must provide a reconciliation between the total capital and operating expenditure provided in the Regulatory Template 2.1 to the capital and operating expenditure recorded in Ergon Energy's Regulatory Accounting Statements and Audited Statutory Accounts.	EECL 0913 CARIN_T2.1 EXPS A1 EECL 0913 CARIN_T2.1 EXPS A2 EECL 0913 CARIN_T2.1 EXPS A3

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.1 Expenditure Summary (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.1 Expenditure Summary

Tables 2.1.1 - 2.1.4: SCS (Capex)/(Opex), ACS (Capex)/(Opex)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	▪ Capital Expenditure reported against activities in Table 2.1.1 have been extracted from individual Templates. ▪ Where Ergon Energy was not required to distinguish expenditure for Public Lighting and Metering services between Capex and Opex nor Standard Control Services or Alternative Control Services in Table 4.1.2, and 4.2.2 respectively, for the purposes of reporting these costs in the Expenditure Summary disaggregation was required to be obtained from subject matter expert supporting files. o All ACS capex overheads have been considered to be corporate overheads as this split is not evident in the template 2.10. o Public lighting has been assumed to be SCS in 2008/09 and 2009/10 in line with QCA classifications, and then ACS for 2010/11 to 2012/13 is in line with AER classifications. o Public lighting light installation and light replacement have been considered as capex, while light maintenance has been considered as opex. o Metering (new) installation and replacement have been assumed to be ACS capex for the purposes of this template. ▪ In accordance with paragraph 2.4 of the Principles and Requirements an additional Excel spread sheet has been prepared which contains the balancing items reported in Regulatory Template 2.1. ▪ Ergon Energy has identified balancing items which relate to duplications in reporting expenditure throughout the templates. ▪ There are no balancing items relating to instances where Ergon Energy has reported capex not on an ‘as-incurred’ basis. That is to say, where Ergon Energy is required to report in $2012/13 real dollars (Table 2.3.1) in respect of Augex expenditure this table is not relevant to the Expenditure Summary. ▪ In order to create an Expenditure Summary total capex that is mutually exclusive and collectively exhaustive as per RIN requirements, along with populating the balancing line item, Ergon Energy inserted Metering and Public Lighting categories.
Use of Actual Information	Where the underlying Expenditure reported in templates is noted as being actual information, the data in the Expenditure Summary Table also reflects actuals.
Source of Actual	Refer to individual Basis of Preparation documents as relevant to the

Minimum Requirements	Ergon Energy Response
Information	underlying Expenditure reported in templates, as drawn through to populate the Expenditure Summary.
Methodology and assumption's used in relation to Actual Information	Refer to individual Basis of Preparation documents as relevant to the underlying Expenditure reported in templates, as drawn through to populate the Expenditure Summary. **Duplications**- A matrix of Category Analysis RIN requirements was prepared which identified reporting of capex, opex, SCS, and ACS, direct, overheads, gifted asset exclusions, for each table. Further checks were identified where instructions or definitions in the Notice identified specific inclusions / exclusions for activities reported. Discussions were held with the GM Finance & Commercial to understand how costs are treated within Ergon Energy's financial systems to identify duplications in various activities reported throughout the CA RIN. Duplicated amounts reported throughout tables were linked through into the reconciliation file identifying the associated activity and amount of the duplication. **Reconciliation between CA RIN and Regulatory Reporting Statements** – Through the same process mentioned for duplications above, differences between the CA RIN and the Regulatory Reporting Statements were identified for Total Capex and Total Opex. **Reconciliation between Regulatory Reporting Statements & Audited Statutory Accounts** – Based on the AER's Issue Register, where reconciliations had already been reported between Audited Statutory Accounts and the Distribution Network Service Provider (SCS, ACS) in the Regulatory Reporting Statements these Statements / Tables have been extracted and provided as attachments. For completeness a summary of these figures for each Initial Regulatory Year (2009 – 2013) and the reconciling difference with explanations have also been provided. Additional information was required to be extracted from the Audited Statutory Accounts in respect of Capex as no such reconciliation had been reported in the past. Extracts of the Work in Progress additions from the Notes to Accounts for Property, Plant and Equipment for the Entity was used to compare to the DNSP Capex figures reported in Regulatory Reporting Statements. As the DNSP operates within the entity Ergon Energy Corporation Limited, which provides both regulated and non-regulated services this is the largest driver of reconciling differences for all years. For the earlier years (2009, 2010) the methodology for allocating costs (CAMP) differed for Statutory and Regulatory purposes i.e.: allocations based on total costs, and labour only respectively.
Use of Estimated Information	Where the underlying Expenditure reported in templates is noted as being estimated information, the data in the Expenditure Summary Table also reflects estimates.
Why is it not possible to use Actual Information, and	Refer to individual Basis of Preparation documents as relevant to the underlying Expenditure reported in templates, as drawn through to

Minimum Requirements	Ergon Energy Response
why an estimate is required	populate the Expenditure Summary.
How the estimate has been produced	Refer to individual Basis of Preparation documents as relevant to the underlying Expenditure reported in templates, as drawn through to populate the Expenditure Summary.

Tables 2.1.5 – 2.1.6: Dual Function Assets (Capex)/(Opex)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has no dual function asset capex.

Ergon Energy Corporation Limited **EECL 0913 CARIN_T2.1 EXPS A2 020614**
2009-2013 Category Analysis RIN
Reconciliation of Total Capex and Opex in Table 2.1
To Regulatory Accounting Statements
To adhere with requirement 2.5 of Appendix E: Principles and Requirements

Requirement:

At paragraph 2.5 of the Principles and Requirements it states, Ergon Energy must provide a reconciliation between the total capital and operating expenditure provided in the Regulatory Template 2.1 to the capital and operating expenditure recorded in Ergon Energy's Regulatory Accounting Statements and Audited Statutory Accounts.

COMMENT:
Ergon Energy has identified all known differences and/or balancing items in reconciling between expenditures provided in Regulatory template 2.1 of the Category Analysis RIN and prior submitted Regulatory Accounting Statements. A difference in treatment of gifted Assets (required to be excluded in the CA RIN) impacts Capex. Other differences between reporting requirements can be attributed to extraction methodologies and analysis performed in estimation of disagregations required.

Standard control services - total gross capex (includes overheads)

	($000s)					
	2009	2010	2011	2012	2013	Notes
Category Analysis RIN	737,939	651,159	757,111	796,017	767,846	Source: CA RIN Table 2.1.1
Gifted Assets (not in CA RIN)	21,586	22,111	15,308	16,796	30,464	Source: CA RIN Templates
Regulatory Accounting Statements	766,432	689,329	773,742	808,223	798,194	(2011, 2012), AP RIN Table 5.1 (2013)
Difference between Reporting Requirements	- 6,907	- 16,059	- 1,323	4,590	116	

Standard control services - total gross opex (includes overheads)

	($000s)					
	2009	2010	2011	2012	2013	Notes
Category Analysis RIN	305,424	335,627	387,790	437,964	422,319	Source: CA RIN Table 2.1.2
Regulatory Accounting Statements	305,549	334,101	387,499	437,595	422,137	Source: QCA RRS - Statement 1 (2009, 2010), AP RIN Table 3.1 (2011, 2012), AP RIN Table 1.1 (2013)
Difference between Reporting Requirements	- 125	1,526	292	368	182	

Alternative control services total gross capex

	($000s)					
	2009	2010	2011	2012	2013	Notes
Category Analysis RIN	3,602	19,522	17,893	22,556	26,034	Source: CA RIN Table 2.1.3
Regulatory Accounting Statements	-	-	6,968	14,761	26,999	Source: QCA RRS - Schedule P (2009, 2010), AP RIN Table 2.8 (2011, 2012), AP RIN Table 5.4 (2013)
Difference between Reporting Requirements	3,602	19,522	10,925	7,795	- 965	

Alternative control services total gross opex

	($000s)					
	2009	2010	2011	2012	2013	Notes
Category Analysis RIN	23,223	24,235	23,571	44,210	43,006	Source: CA RIN Table 2.1.4
Regulatory Accounting Statements	23,220	24,233	23,785	45,050	43,008	Source: QCA RRS - Statement 1 (2009, 2010), AP RIN Table 7a (2011, 2012), AP RIN Table 1.1 (2013)
Difference between Reporting Requirements	3	2	- 215	- 841	- 2	

Dual function assets capex

	($000s)					
	2009	2010	2011	2012	2013	Notes
Category Analysis RIN						Not applicable
Regulatory Accounting Statements						Not applicable
Difference between Reporting Requirements						Not applicable
Commentary:	Ergon Energy does not have dual function assets.					

Dual function assets opex

	($000s)					
	2009	2010	2011	2012	2013	Notes
Category Analysis RIN						Not applicable
Regulatory Accounting Statements						Not applicable
Difference between Reporting Requirements						Not applicable
Commentary:	Ergon Energy does not have dual function assets.					

Acronyms:
ASA - Audited Statutory Accounts
QCA RRS - Queensland Competition Authority Regulatory Reporting Statements
AP RIN - Australian Energy Regulator Annual Performance Regulatory Information Notice
RAS - Regulatory Accounting Statements consisting of QCA RRS and AP RIN

Ergon Energy Corporation Limited
2009-2013 Category Analysis RIN
Reconciliation of Total Capex and Opex
in Regulatory Accounting Statements to Audited Statutory Accounts
To adhere with requirement 2.5 of Appendix E: Principles and Requirements

Requirements:

At paragraph 2.5 of the Principles and Requirements it states, Ergon Energy must provide a reconciliation between the total capital and operating expenditure provided in the Regulatory Template 2.1 to the capital and operating expenditure recorded in Ergon Energy's Regulatory Accounting Statements and Audited Statutory Accounts.

Additionally, in accordance with the AER's issues register for the CA RIN, to the extent the Regulatory Accounting Statements include a reconciliation to amounts in the Audited Statutory Accounts, Ergon Energy has provided a copy of the Regulatory Accounting Statements as stated by the the AER to be sufficient to comply with this requirement. Ergon Energy notes that the AER is seeking to identify items relevant to demonstrating this reconciliation.

Standard control services and Alternative Control Services capex (includes overheads)

	2009 $000	2010 $000	2011 $000	2012 $000	2013 $000
Audited Statutory Accounts	816,797	762,127	841,347	872,078	871,879
Regulatory Accounting Statements	766,432	689,329	780,710	822,985	825,193
Reconciling difference - Amount	**50,365**	**72,798**	**60,637**	**49,093**	**46,686**
- Explanation	Non-regulated component, cost allocation adjustments	Non-regulated component, cost allocation adjustments	Non-regulated component	Non-regulated component	Non-regulated component
Source	QCA RRS - Schedule P; ASA Note 11: PP&E	QCA RRS - Schedule P; ASA Note 11: PP&E	2010/11 AP RIN Table 2.1 & 2.8 ASA Note 11: PP&E	2011/12 AP RIN Table 2.1 & 2.8 ASA Note 11: PP&E	2012/13 AP RIN Table 5.1 & 5.4 ASA Note 11: PP&E

* Street lighting and Large Customer Connections were reclassified as Alternative Control Services (from Prescribed Distribution Services) from the 1 July 2010, resulting in reporting of capital expenditure for these years.

Standard control services and Alternative Control Services opex (includes overheads)

No reconciliation required for Opex, as there are reconciliations in Ergon Energy's Regulatory Accounting Statements which meet the requirements in accordance with the AER's issues register.

Acronyms:
ASA - Audited Statutory Accounts
QCA RRS - Queensland Competition Authority Regulatory Reporting Statements
AP RIN - Australian Energy Regulator Annual Performance Regulatory Information Notice
RAS - Regulatory Accounting Statements consisting of QCA RRS and AP RIN

Extracts Attached:
ASA - Extracts from Audited Statutory Accounts relating to the additions in Work in Progress (2009 - 2013)
RAS - Extracts from QCA RRS (2009 -2010), and AP RIN (2011 - 2013).

Category Analysis RIN
Basis of Preparation

Template 2.2 Replacement Expenditure

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.2 Replacement Expenditure of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.2 Replacement Expenditure (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.2 Replacement Expenditure, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirement/s were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.2 Replacement Expenditure (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.2 Replacement Expenditure

Table 2.2.1 - Cost Metrics by Asset Category

Ergon Energy provides the below comments specific to individual asset groups / categories represented in Template 2.2.

Generally, in regards to requirements for Template 2.2, Table 2.2.1, Ergon Energy notes that:

- Where asset sub-categories corresponding to the prescribed asset categories were provided, the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category.
- Additional rows were inserted to provide a clear indication of the asset category applicable to each sub-category.
- In instances where expenditure is reported associated with Asset Refurbishments / Life Extensions Capex, Ergon Energy has inserted additional rows at the bottom of the table for the relevant asset group to account for this. The Asset Category name is followed by “Refurbished” in this regard.
- Additional rows have been inserted to account for assets not accounted for under the prescribed asset group categories or sub-categorisations.
- The sum of the individual asset categories, including any additional sub-category, additional other asset category or Asset Refurbishments / Life Extensions asset category expenditure reconciles to the total expenditure of the asset group.
- Ergon Energy has reported replacement volumes by asset group in Template 2.2, Table 2.2.1 that equal the applicable replacement volume data provided in table 2.2.2. It should be noted that the total poles in table 2.2.2 does not include pole staking, because a pole stake is a reinforcement applied to support a pole and not a pole asset in and of itself.
- The sum of the asset group replacement expenditures is equal to the total replacement expenditure contained in template 2.1 (Expenditure Summary)
- Where estimated expenditure data has been provided on the basis of historical data that has included works across asset groups, Ergon Energy has provided the Asset Age Profile data in Template 5.2 against the most elementary asset category. Documentation of instances where back cast unit costs generated have involved allocations of historical records that include expenditure across asset groups has been provided.

- Activity Codes from Ergon Energy's General Ledger have been used to identify expenditure on Asset Replacement using the three (3) activity codes which align with this activity. They have also been used to identify Replacement Asset Quantity from stores issues for many distribution assets and in some instances quantity of assets issued against "Maintenance" activity codes to count failures. The Activity Code for Other is also listed as occasionally some of this expenditure contains an element of asset replacement. This is documented in detail for specifics assets in the individual asset tables in the BoP.

Activity Code	Description	Budget	Driver
53120	Corrective Reg Lines	OPEX	Maintenance
53150	Corrective Reg Subs	OPEX	Maintenance
54100	Forced Regulated Maintenance	OPEX	Maintenance
C2000	Network Refurbishment	CAPEX	Replacement
C2020	Ageing Asset Replacement	CAPEX	Replacement
C2130	Street Lighting Refurbishment	CAPEX	Replacement
C2050	Other Regulated System Capex	CAPEX	Other

Table 1: Staking of a Wooden Pole

Minimum Requirements	Ergon Energy Response [Staking of a Wooden Pole]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1: Replacement Expenditure Volumes and Asset Failures, by Asset Category, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following variables: ▪ Expenditure by Asset Category (2008/09-2012/13) ▪ Asset Replacements (2008/09-2012/13) ▪ Asset Failures (2008/09-2012/13)
Why is it not possible to use Actual Information,	It was not possible to use Actual Information, and an estimate is required in relation to Expenditure By Asset Category (2008/09-2012/13) because the corporate ERP and associated processes were not envisioned or configured with the level of detail

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response [Staking of a Wooden Pole]</th></tr>
<tr><td>and why an estimate is required</td><td>requested by the AER in mind. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist.

It was not possible to use Actual Information, and an estimate is required in relation to Asset Replacements (2008/09-2012/13) because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access data relating to each asset replaced does not exist.

It was not possible to use Actual Information, and an estimate is required in relation to Asset Failures because Ergon Energy's Asset Management systems and processes did not allow adequate tracking of equipment once it is no longer in service.</td></tr>
<tr><td>How the estimate has been produced</td><td>In relation to Expenditure, Ergon Energy has developed the following estimation methodology:

Plant Cost Allocation Method

1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger (data in the Ellipse financial module) using the three (3) activity codes which align with this activity: These codes are:

<table>
<tr><th>Activity Code</th><th>Description</th><th>Budget</th><th>Driver</th></tr>
<tr><td>53120</td><td>Corrective Reg Lines</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>53150</td><td>Corrective Reg Subs</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>54100</td><td>Forced Regulated Maintenance</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>C2000</td><td>Network Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2020</td><td>Ageing Asset Replacement</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2130</td><td>Street Lighting Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2050</td><td>Other Regulated System Capex</td><td>CAPEX</td><td>Other</td></tr>
</table>

2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets are replaced is insignificant and not reported separately.

3) That portion of Asset Replacement expenditure associated with the asset group - Lines and Distribution Plant (poles, pole tops, conductor, cable, services, distribution transformers, distribution switchgear and street lighting) has been determined from 'J Code' combinations.

4) The number of replacements is determined from maintenance work orders.

5) The total expenditure on Pole Stakes (material only) is extracted from the Ellipse inventory module, as a weighted average cost of the items in store. The "plant cost" for each financial year for the pole staking asset category is calculated by multiplying the number of pole stakes by the average cost of procurement.

6) The ratio may be adjusted to enable correction for errors caused when the ratio of labour to material costs varies from the average, or low volumes of assets lead to</td></tr>
</table>

Minimum Requirements	Ergon Energy Response [Staking of a Wooden Pole]
	significant purchase cost variation. The unit plant cost is reviewed by the SME to confirm that the value is consistent with their experience. For the small number that were not consistent such as staking of poles, the ratio is adjusted to bring the value in line with the SME's expected values. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit asset cost is reviewed and plant costs adjusted by the SME to ensure that the value is consistent with their experience. In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good proxy for the distribution of other costs associated with installing the Staking Of A Wooden Pole. In relation to **Asset Replacement** information Ergon Energy has developed an estimate based on the following approach: ▪ As Staking pole is an activity and not an asset Ergon Energy has provided the number of poles staked per year based on Works Order data. Ergon Energy works orders associated with staking poles in its Ellipse works management module. In developing this estimate, Ergon Energy has assumed that work Orders are completed. Ergon Energy considers that the best estimate has been provided for Asset Replacement information on the basis that: ▪ Pole staking is not an asset but a refurbishment activity, therefore works orders are the appropriate record. ▪ Works order information is derived from Ergon Energy's Ellipse works management module. In relation to **Asset Failures** (for Staking of Poles), Ergon Energy has developed the following estimation methodology: ▪ Works Orders for pole maintenance have been reviewed. The works orders were filtered to include only staked poles and the number of poles replaced were counted by year. The number of (staked) poles replaced provides a measure of asset failures, since pole stakes are not replaced for reasons other than pole replacement. In developing this estimate, Ergon Energy has assumed that Staked (Nailed) poles are not replaced for reasons other than failure.

Minimum Requirements	Ergon Energy Response [Staking of a Wooden Pole]
	Ergon Energy considers that the best estimate has been provided for Asset Failure information for Staked Poles on the basis that: ▪ As the pole stakes are not treated as an asset, but an activity, the works orders are therefore, the most effective method to track them. ▪ The number of (staked) poles replaced provides a measure of asset failures. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. ▪ Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 2: Poles, Pole Top Structures

Minimum Requirements	Ergon Energy Response [Poles, Pole Top Structures]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1: Replacement Expenditure Volumes and Asset Failures, by Asset Category, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for : ▪ Asset failure data for High Voltage Poles, which include: o > 11 kV & < = 22 kV; WOOD o > 22 kV & < = 66 kV; WOOD o > 66 kV & < = 132 kV; WOOD o > 132 kV; WOOD o > 1 kV & < = 11 kV; STEEL o > 11 kV & < = 22 kV; STEEL o > 22 kV & < = 66 kV; STEEL o > 66 kV & < = 132 kV; STEEL o > 132 kV; STEEL

Minimum Requirements	Ergon Energy Response [Poles, Pole Top Structures]
	▪ Asset failure data for High Voltage Pole top structures which include: o > 1 kV & < = 11 kV o > 11 kV & < = 22 kV o > 22 kV & < = 66 kV o > 66 kV & < = 132 kV o > 132 kV
Source of Actual Information	Actual Information for Asset Failure volumes for High Voltage Poles, Pole top structures and Overhead conductor only was sourced from e-Safe (corporate record of safety issues)
Methodology and assumption's used in relation to Actual Information	Asset failure data for High Voltage Poles, Pole top structures and Overhead conductor. In order to obtain the information, it was necessary for Ergon Energy to manipulate the e-Safe (corporate record of safety issues) data into to three main Asset groups being, Conductor (including Deadend, Splice, Tie and Clamp) failures, Pole Top Structure (including Crossarm and Insulators) failures and Pole (including Stay) failures. The data has been filtered by financial year and voltage (where known). Data with an unknown or undefined voltage has been excluded. In doing so it was assumed that Dangerous Electrical Event as defined by the *Electrical Safety Act 2002 (QLD)* are failures. This data excludes extreme or atypical weather events.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following variables: ▪ Expenditure by Asset Category (2008/09-2012/13) o Poles o Pole top structures ▪ Asset Replacements (2008/09-2012/13) o Poles o Pole top structures ▪ Asset Failures (2008/09-2012/13) Poles (Low Voltage) o < = 1 kV; WOOD o < = 1 kV; CONCRETE o < = 1 kV; STEEL ▪ Pole top structures (Low Voltage) o < = 1 kV
Why is it not possible to use Actual Information, and why an	It was not possible to use Actual Information, and an estimate is required in relation to Expenditure by Asset Category and Asset Replacements for all classes in these categories because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. Processes within

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response [Poles, Pole Top Structures]</th></tr>
<tr><td>estimate is required</td><td>Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist.

It was not possible to use Actual Information, and an estimate is required in relation to Asset Failures for all classes in these categories because Ergon Energy's Asset Management system and processes did not allow adequate tracking of equipment once it is no longer in service. Whilst this information is not routinely available in the period of the backcast, Ergon Energy is working to implement capability that will allow provision of this data in the future.</td></tr>
<tr><td>How the estimate has been produced</td><td>In relation to expenditure for all asset categories, Ergon Energy has developed the following estimation methodology:

Plant Cost Allocation Method

1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are:

<table>
<tr><th>Activity Code</th><th>Description</th><th>Budget</th><th>Driver</th></tr>
<tr><td>53120</td><td>Corrective Reg Lines</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>53150</td><td>Corrective Reg Subs</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>54100</td><td>Forced Regulated Maintenance</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>C2000</td><td>Network Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2020</td><td>Ageing Asset Replacement</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2130</td><td>Street Lighting Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2050</td><td>Other Regulated System Capex</td><td>CAPEX</td><td>Other</td></tr>
</table>

2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets are replaced is insignificant and not reported separately.

3) That portion of Asset Replacement expenditure associated with the Asset Groups - Lines and Distribution Plant (poles, pole tops, conductor, cable, services, distribution transformers, distribution switchgear and street lighting) has been determined from 'J Code' combinations.

4) For each asset category the number of asset replacements for each financial year is determined from stores issues of the key plant item allocated to the activity codes from step 1. The key plant items counted are those stores items that become the asset category item once installed

5) The "plant cost" for each asset category is taken as the total stores issue cost for the key plant item for each financial year and is extracted from the Ellipse inventory module.

6) For the Lines and Distribution Plant, the expenditure for the financial year is calculated as the proportion of the ratio of the plant cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total</td></tr>
</table>

Minimum Requirements	Ergon Energy Response [Poles, Pole Top Structures]
	expenditure costs are apportioned appropriately to the each asset category. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit plant cost is reviewed and plant weightings altered by the SME to ensure that the value is consistent with their experience. In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good starting point for the distribution of other costs associated with installing the asset. In relation to Asset Failure, Ergon Energy has developed an estimate based on the following approach: ▪ Failures for LV Poles and Pole Top Structures were estimated from the HV Failures by applying the population ratio for LV to HV assets from the data in table 5.2.1. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 3: Overhead Conductor, Underground Cable and Service Lines

Minimum Requirements	Ergon Energy Response [Overhead Conductor, Underground Cable and Service Lines]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1: Replacement Expenditure Volumes and Asset Failures, by Asset Category, in accordance with the Notice requirements, including the Principles and Requirements

Minimum Requirements	Ergon Energy Response [Overhead Conductor, Underground Cable and Service Lines]
	set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for : ▪ Asset failure data for High Voltage Overhead conductor which include: o > 1 kV & < = 11 kV o > 11 kV & < = 22 kV ; SWER o > 11 kV & < = 22 kV ; SINGLE-PHASE o > 11 kV & < = 22 kV ; MULTIPLE-PHASE o > 22 kV & < = 66 kV o > 66 kV & < = 132 kV o > 132 kV
Source of Actual Information	Actual Information for Asset Failure volumes for High Voltage Overhead conductor only was sourced from e-Safe (corporate record of safety issues).
Methodology and assumption's used in relation to Actual Information	Asset Failure Data for High Voltage Overhead conductor. In order to obtain the information, it was necessary for Ergon Energy to manipulate the e-Safe data into to three main Asset groups being, Overhead Conductor (including Deadend, Splice, Tie and Clamp) failures, Pole Top Structure (including Crossarm and Insulators) failures and Pole (including Stay) failures. The data has been filtered by financial year and voltage (where known). Data with an unknown or undefined voltage has been excluded. This data excludes extreme or atypical weather events. In doing so it was assumed that Dangerous Electrical Event as defined by the *Electrical Safety Act 2002 (QLD)* constitute a failure.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following variables: ▪ Expenditure by Asset Category (2008/09-2012/13) o Overhead conductors o Underground Cables o Service Lines ▪ Asset Replacements (2008/09-2012/13) o Overhead conductors o Underground Cables o Service Lines ▪ Asset Failures (2008/09-2012/13) o Overhead Conductors (Low Voltage), < = 1 kV o Underground cables o Service Lines

Minimum Requirements	Ergon Energy Response [Overhead Conductor, Underground Cable and Service Lines]
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to Expenditure and Asset Replacements for all asset categories because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist. It was not possible to use Actual Information, and an estimate is required in relation to Asset Failures (except for HV OH conductors) because Ergon Energy's Asset Management system and processes did not allow adequate tracking of equipment once it is no longer in service. Whilst this information is not routinely available in the period of the back cast, Ergon Energy is working to implement capability that will allow provision of this data in the future.
How the estimate has been produced	In relation to Expenditure For Each Asset Category, Ergon Energy has developed the following estimation methodology:

1) All Low Voltage (<= 11kV) Services are included under the two "SIMPLE TYPE" categories below:

< = 11 kV ; RESIDENTIAL ; SIMPLE TYPE

< = 11 kV ; COMMERCIAL & INDUSTRIAL ; SIMPLE TYPE

2) This is because Ergon Energy has no sensible way to differentiate the "COMPLEX TYPE" Low Voltage (<= 11kV) services.

< = 11 kV ; RESIDENTIAL ; COMPLEX TYPE

< = 11 kV ; COMMERCIAL & INDUSTRIAL ; COMPLEX TYPE

3) The remaining High Voltage categories of services are constructed of assets which are reported as the individual assets from which they are constructed.

Plant Cost Allocation Method

1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are:

Activity Code	Description	Budget	Driver
53120	Corrective Reg Lines	OPEX	Maintenance
53150	Corrective Reg Subs	OPEX	Maintenance
54100	Forced Regulated Maintenance	OPEX	Maintenance
C2000	Network Refurbishment	CAPEX	Replacement
C2020	Ageing Asset Replacement	CAPEX	Replacement
C2130	Street Lighting Refurbishment	CAPEX	Replacement
C2050	Other Regulated System Capex	CAPEX	Other

2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets

Minimum Requirements	Ergon Energy Response [Overhead Conductor, Underground Cable and Service Lines]

are replaced is insignificant and not reported separately.

3) That portion of Asset Replacement expenditure associated with the **asset group - Lines and Distribution Plant (poles, pole tops, conductor, cable, services, distribution transformers, distribution switchgear and street lighting)** has been determined from ‘J Code’ combinations.

4) For each asset category the number of asset replacements for each financial year is determined from stores issues of the key plant item allocated to the activity codes from step 1. The key plant items counted are those stores items that become the asset category item once installed. In some cases a ratio is applied to convert the stores issue quantity to the asset quantity e.g. 3,000 metres of single core UG 11kV cable becomes one (1) circuit kilometre of “> 1 kV & < = 11 kV UNDERGROUND CABLE”. For unitised assets like poles or distribution transformers the ratio is 1:1. It is noted the number of service line replacements and expenditure are higher commencing 2011/12 due to the open wire service replacement program.

5) The “plant cost” for each asset category is taken as the total stores issue cost for the key plant item for each financial year is extracted from the Ellipse inventory module.

6) For the **Lines and Distribution Plant**, the expenditure for the financial year is calculated as the proportion of the ratio of the plant cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total expenditure costs are apportioned appropriately to the each asset category.

In developing this estimate, Ergon Energy has made the assumptions that:

- All replacement expenditure is allocated across the Asset Categories in Table 2.2.1.
- The ratio of material costs to other direct costs (labour etc.), is consistent across assets.
- There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings)

Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit plant cost is reviewed and plant weightings altered by the SME to ensure that the value is consistent with their experience. In the case of the conductor replacement, plant weightings have been adjusted achieve alignment with standard estimates, sensible relativity between the various asset categories and to set the total expenditure for 2012/13 to approximate the expenditure on conductor able to be identified with J Code combinations.

In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good proxy for the distribution of other costs associated with installing the asset.

Minimum Requirements	Ergon Energy Response [Overhead Conductor, Underground Cable and Service Lines]
	Asset Failures – Overhead Conductors In relation to Asset Failures (for Overhead Conductors), Ergon Energy has developed the following estimation methodology: ▪ The ratio of HV circuit kilometres to LV circuit kilometres has been applied to the total failures from volumes for High Voltage Overhead conductor sourced from e-Safe (corporate record of safety issues) to estimate the failures of LV conductors. ***Asset Failures – Service Lines*** In relation to **Asset Failure**, Ergon Energy has developed an estimate based on the following approach: ▪ Service Lines are invariably replaced in response to the ability to “perform its intended function safely” as per the AER definition of Asset failure. Accordingly, the stores issues records for these assets costed to the OPEX Maintenance and CAPEX replacement activity codes are considered to be Failures for service lines. ***Asset Failures – Underground Cables*** In relation to Asset Failures (for Underground Cables), Ergon Energy has developed the following estimation methodology: ▪ FeederStat was used to identify an outage which is then attributed by some engineering knowledge and experience to a particular asset class. This data excludes extreme or atypical weather events. In developing this estimate Ergon Energy has assumed that all failures will lead to an outage. Ergon Energy considers that the best estimate has been provided for Asset Failures for substation plant categories on the basis that: ▪ a failure will lead to an outage, and the process for reporting these outages is consistently followed. It has not been possible from data available to exclude external events however Ergon Energy does not believe this has a material impact. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy’s replacement costs when averaged over multiple years.

Table 4: Distribution Transformers, Distribution Circuit Breakers and Fuses

Minimum Requirements	Ergon Energy Response [Distribution Transformers, Distribution Circuit Breakers and Fuses]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1: Replacement Expenditure Volumes and Asset Failures, by Asset Category, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following variables: ▪ Expenditure by Asset Category (2008/09-2012/13) ▪ ASSET REPLACEMENTS (2008/09-2012/13) ▪ ASSET FAILURES (2008/09-2012/13)for Distribution Transformers for the Asset Categories: o POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE o POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE o POLE MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE o POLE MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE o POLE MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE o POLE MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE o POLE MOUNTED ; > 22kV ; < = 60 kVA ; SINGLE PHASE o POLE MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE o POLE MOUNTED ; > 22kV ; > 600 kVA ; SINGLE PHASE o POLE MOUNTED ; > 22kV ; < = 60 kVA ; MULTIPLE PHASE o POLE MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE o POLE MOUNTED ; > 22kV ; > 600 kVA ; MULTIPLE PHASE o KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE o KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE o KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE

Minimum Requirements	Ergon Energy Response [Distribution Transformers, Distribution Circuit Breakers and Fuses]
	o KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE o KIOSK MOUNTED ; < = 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE o KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE o KIOSK MOUNTED ; > 22kV ; < = 60 kVA ; SINGLE PHASE o KIOSK MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE o KIOSK MOUNTED ; > 22kV ; > 600 kVA ; SINGLE PHASE o KIOSK MOUNTED ; > 22kV ; < = 60 kVA ; MULTIPLE PHASE o KIOSK MOUNTED ; > 22kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE o KIOSK MOUNTED ; > 22kV ; > 600 kVA ; MULTIPLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; < = 60 kVA ; SINGLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 60 kVA AND < = 600 kVA ; SINGLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVA ; SINGLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; < = 60 kVA ; MULTIPLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 60 kVA AND < = 600 kVA ; MULTIPLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVA ; MULTIPLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; < = 15 MVA Note: In the case of Ergon Energy assets the “GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVA ; MULTIPLE PHASE” and “GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; < = 15 MVA” categories include both distribution transformers and zone substation transformers. ▪ Distribution Switchgear o < = 11 kV ; FUSE o < = 11 kV ; CIRCUIT BREAKER o > 11 kV & < = 22 kV ; CIRCUIT BREAKER Note: Ergon Energy has reported all distribution fuses in the category “< = 11kV; FUSE”. In Ergon Energy’s case this will include LV, 11kV, 22kV and 33kV fuses.
Why is it not possible to use Actual Information, and why an estimate is	It was not possible to use Actual Information, and an estimate is required in relation to Expenditure By Asset Category and Asset Replacements for these assets because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response [Distribution Transformers, Distribution Circuit Breakers and Fuses]</th></tr>
<tr><td>required</td><td>the ability to directly access the individual costs of each asset replaced does not exist.

It was not possible to use Actual Information, and an estimate is required in relation to Asset Failures because Ergon Energy's Asset Management system and processes did not allow adequate tracking of equipment once it is no longer in service.</td></tr>
<tr><td>How the estimate has been produced</td><td>In relation to Expenditure For Each Asset Category, Ergon Energy has developed the following estimation methodology:

Plant Cost Allocation Method

1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are:

<table>
<tr><th>Activity Code</th><th>Description</th><th>Budget</th><th>Driver</th></tr>
<tr><td>53120</td><td>Corrective Reg Lines</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>53150</td><td>Corrective Reg Subs</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>54100</td><td>Forced Regulated Maintenance</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>C2000</td><td>Network Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2020</td><td>Ageing Asset Replacement</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2130</td><td>Street Lighting Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2050</td><td>Other Regulated System Capex</td><td>CAPEX</td><td>Other</td></tr>
</table>

2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets are replaced is insignificant and not reported separately..

3) That portion of Asset Replacement expenditure associated with the asset group - Lines and Distribution Plant (poles, pole tops, conductor, cable, services, distribution transformers, distribution switchgear and street lighting) has been determined from 'J Code' combinations.

4) For each asset category the number of asset replacements for each financial year is determined from stores issues of the key plant item allocated to the activity codes from step 1. The key plant items counted are those stores items that become the asset category item once installed. In some cases a ratio is applied to convert the stores issue quantity to the asset quantity e.g. A three (3) switch Ring Main Unit is counted as 3 switches. For unitised assets like poles or distribution transformers the ratio is 1:1.

5) In the case of fuses, replacements have been obtained from stores issues of fuse carrier against CAPEX activity codes for replacement.

6) The "plant cost" for each asset category is taken as the total stores issue cost for the key plant item for each financial year is extracted from the Ellipse inventory module.

7) For the asset group - Lines and Distribution Plant, the expenditure for the financial year is calculated as the proportion of the ratio of the plant</td></tr>
</table>

Minimum Requirements	Ergon Energy Response [Distribution Transformers, Distribution Circuit Breakers and Fuses]
	cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total expenditure costs are apportioned appropriately to the each asset category. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit plant cost is reviewed and plant weightings altered by the SME to ensure that the value is consistent with their experience. In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good proxy for the distribution of other costs associated with installing the asset. In relation to ***Asset Failure***, Ergon Energy has developed an estimate based on the following approach: ▪ The maintenance practice for distribution transformers and distribution circuit breakers is to run them to failure and then replace, therefore all replacements are assumed to be failures. It has not been possible from data available to exclude external events however Ergon Energy does not believe this has a material impact. ▪ Asset Fuse failures have been obtained from stores issues of fuse carriers against OPEX activity codes for maintenance. Ergon Energy considers that the best estimate has been provided for Asset Failure information for Distribution Transformers and Circuit Breakers on the basis that these assets are “run to fail”, and therefore only replaced when they fail. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy’s replacement costs when averaged over multiple years.

Table 5: Distribution Switches and Public Lighting

Minimum Requirements	Ergon Energy Response [Distribution Switches and Public Lighting]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1: Replacement Expenditure Volumes and Asset Failures, by Asset Category, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has limited reporting in Template 2.2 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. This results in reporting for public lighting for the years 2008/09 and 2009/10 only. As the provision of street lighting services was reclassified as an Alternative Control Service from 1 July 2010 associated costs and therefore metrics have not been reported for years thereafter (2010/11 – 2012/13) in Table 2.2.1
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following variables: ▪ Expenditure By Asset Category (2008/09-2012/13) ▪ Asset Replacements (2008/09-2012/13) ▪ Asset Failures (2008/09-2012/13) FOR DISTRIBUTION Switches: o < = 11 kV ; SWITCH o < = 11 kV ; CIRCUIT BREAKER o > 11 kV & < = 22 kV ; SWITCH o > 11 kV & < = 22 kV ; CIRCUIT BREAKER o > 22 kV & < = 33 kV ; SWITCH ▪ Public Lighting
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to Expenditure By Asset Category and Asset Replacements for these assets because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist. It was not possible to use Actual Information, and an estimate is required in relation to Asset Failures because Ergon Energy's Asset Management system and processes did

Minimum Requirements	Ergon Energy Response [Distribution Switches and Public Lighting]
	not allow adequate tracking of equipment once it is no longer in service.
How the estimate has been produced	In relation to Expenditure For Each Asset Category, Ergon Energy has developed the following estimation methodology:

Plant Cost Allocation Method

1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are:

Activity Code	Description	Budget	Driver
53120	Corrective Reg Lines	OPEX	Maintenance
53150	Corrective Reg Subs	OPEX	Maintenance
54100	Forced Regulated Maintenance	OPEX	Maintenance
C2000	Network Refurbishment	CAPEX	Replacement
C2020	Ageing Asset Replacement	CAPEX	Replacement
C2130	Street Lighting Refurbishment	CAPEX	Replacement
C2050	Other Regulated System Capex	CAPEX	Other

2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets are replaced is insignificant and not reported separately..

3) That portion of Asset Replacement expenditure associated with the **asset group - Lines and Distribution Plant (poles, pole tops, conductor, cable, services, distribution transformers, distribution switchgear and street lighting)** has been determined from ‘J Code’ combinations.

4) For each asset category the number of asset replacements for each financial year is determined from stores issues of the key plant item allocated to the activity codes from step 1. The key plant items counted are those stores items that become the asset category item once installed.

5) The “plant cost” for each asset category is taken as the total stores issue cost for the key plant item for each financial year is extracted from the Ellipse inventory module.

6) For the **asset group - Lines and Distribution Plant**, the expenditure for the financial year is calculated as the proportion of the ratio of the plant cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total expenditure costs are apportioned appropriately to the each asset category.

In developing this estimate, Ergon Energy has made the assumptions that:

- All replacement expenditure is allocated across the Asset Categories in Table 2.2.1.
- The ratio of material costs to other direct costs (labour etc.), is consistent across assets.
- There is sufficient volume in each asset class to smooth price fluctuations (this has

Minimum Requirements	Ergon Energy Response [Distribution Switches and Public Lighting]
	been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit plant cost is reviewed and plant weightings altered by the SME to ensure that the value is consistent with their experience. In the case of the public lighting, plant weightings have been adjusted to set the total expenditure for 2012/13 to approximate the expenditure seen against activity code C2130. this This recently introduced C2130 activity code now identifies public lighting replacement expenditure separate to other replacement expenditure. In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good proxy for the distribution of other costs associated with installing the asset. In relation to ***Asset Failure,*** Ergon Energy has developed an estimate based on the following approach: ▪ The stores issues costs for these assets costed to the OPEX code are considered to be Failures. Ergon Energy considers that the best estimate has been provided for Asset Failure information for Distribution switches and public lighting on the basis that planned replacements will be costed to CAPEX, augmentation will be costed to AUGEX and replacing failures will be costed to OPEX, and as we are using the issue cost of the replacement key asset then we are including the appropriate records. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 6: Zone Transformers, Zone Substation Switchgear

Minimum Requirements	Ergon Energy Response [Zone Transformers, Zone Substation Switchgear]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual	Ergon Energy has not provided Actual Information, in accordance with the AER's

Minimum Requirements	Ergon Energy Response [Zone Transformers, Zone Substation Switchgear]
Information	definition for the variables in this asset category.
Source of Actual Information	Ergon Energy has not provided Actual Information, in accordance with the AER's definition for the variables in this asset category.
Methodology and assumption's used in relation to Actual Information	Ergon Energy has not provided Actual Information, in accordance with the AER's definition for the variables in this asset category.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following Transformers: ▪ Expenditure by Asset Category (2008/09-2012/13) ▪ Asset replacement (2008/09-2012/13) ▪ Asset failure (2008/09-2012/13) ▪ For: o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVA ; MULTIPLE PHASE o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; < = 15 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; > 15 MVA AND < = 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; > 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < = 66 KV ; < = 15 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < = 66 KV ; > 15 MVA AND < = 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < = 66 KV ; > 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < = 132 KV ; < = 100 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < = 132 KV ; > 100 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 KV ; < = 100 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 KV ; > 100 MVA Note: In the case of Ergon Energy assets the "GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVA ; MULTIPLE PHASE" and "GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; < = 15 MVA" categories include both distribution transformers and zone

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response [Zone Transformers, Zone Substation Switchgear]</th></tr>
<tr><td></td><td>substation transformers.</td></tr>
<tr><td>Why is it not possible to use Actual Information, and why an estimate is required</td><td>It was not possible to use Actual Information, and an estimate is required relation to Expenditure By Asset Category (2008/09-2012/13), because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist.

An estimation methodology has been developed in relation to providing expenditure data for individual asset categories.

It was not possible to use Actual Information, and an estimate is required in relation to ASSET REPLACEMENT And ASSET FAILURES because Ergon Energy's Asset Management system and processes did not allow adequate tracking of equipment once it is no longer in service.</td></tr>
<tr><td>How the estimate has been produced</td><td>Expenditure By Asset Category (2008/09-2012/13)

In relation to expenditure for each asset category, Ergon Energy has developed the following estimation methodology:

Plant Cost Allocation Method

1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are:
<table>
<tr><th>Activity Code</th><th>Description</th><th>Budget</th><th>Driver</th></tr>
<tr><td>53120</td><td>Corrective Reg Lines</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>53150</td><td>Corrective Reg Subs</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>54100</td><td>Forced Regulated Maintenance</td><td>OPEX</td><td>Maintenance</td></tr>
<tr><td>C2000</td><td>Network Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2020</td><td>Ageing Asset Replacement</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2130</td><td>Street Lighting Refurbishment</td><td>CAPEX</td><td>Replacement</td></tr>
<tr><td>C2050</td><td>Other Regulated System Capex</td><td>CAPEX</td><td>Other</td></tr>
</table>
2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets are replaced is insignificant and not reported separately..

3) The number of Asset Replacements is determined by identification of all scrapped assets (in this class) and matching the previous location with new equipment to obtain the year replaced. Scrapped is a term used and is equivalent to removed from service. To identify these scrapped assets, data tags such as Deleted, Out of Service, Disposed and Scrapped, as well as a hierarchy group called scrapped were used.

4) That portion of Asset Replacement expenditure associated with the Asset Group – Substation Plant, (zone transformers, substation switchgear, protection and control equipment, and other) has been determined from 'J Code' combinations.</td></tr>
</table>

Minimum Requirements	Ergon Energy Response [Zone Transformers, Zone Substation Switchgear]
	5) Plant unit costs for representative items for each asset category have been obtained from Ergon Energy's current period contract rates for procurement of these items. 6) The "plant cost" for each financial year for each asset category is calculated by multiplying the number of replacements by the current cost of procurement of the representative item. 7) For the **Asset Group – Substation Plant**, the expenditure for the financial year is calculated as the proportion of the ratio of the plant cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total expenditure costs are apportioned appropriately to the each asset category. 8) The ratio may be adjusted to enable correction for errors caused when the ratio of labour to material costs varies from the average, or low volumes of assets lead to significant purchase cost variation. The unit plant cost is reviewed by the SME to confirm that the value is consistent with their experience. For the few that were not consistent, the ratio is adjusted to bring the value in line with the Standard Estimate which is Ergon Energy's expectation of cost of install of this asset. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) ***Asset Replacement*** (2008/09-2012/13) In relation to Asset Replacement, Ergon Energy has developed an estimate based on the following approach: ▪ Identification of all scrapped assets (in this class) and matching the previous location with new equipment to obtain the year replaced. In developing this estimate Ergon Energy has made the following assumptions: ▪ All scrapped assets are marked as such in the data source ▪ It was possible to determine where the asset was when it failed. ***Asset Failure***(2008/09-2012/13) In relation to Asset Failures, Ergon Energy has developed the following estimation methodology: FeederStat was used to identify an outage which is then attributed by some engineering knowledge and experience to a particular asset class. This data excludes extreme or atypical weather events. In developing this estimate Ergon Energy has assumed that all failures will lead to an outage.

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response [Zone Transformers, Zone Substation Switchgear]</th></tr>
<tr><td></td><td>Ergon Energy considers that the best estimate has been provided for Asset Failures for substation plant categories on the basis that:
▪ a failure will lead to an outage, and the process for reporting these outages is consistently followed. It has not been possible from data available to exclude external events however Ergon Energy does not believe this has a material impact.
NOTE: It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed:
▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years
▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost.
Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.</td></tr>
</table>

Table 7: Other

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response [Other]</th></tr>
<tr><td rowspan="2">Consistency with the requirements of the Notice</td><td>Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.</td></tr>
<tr><td>Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.</td></tr>
<tr><td>Use of Actual Information</td><td>Ergon Energy has provided Actual Information, in accordance with the AER's definition for:
▪ Static Var Compensators
o Expenditure for the period (2008/09 – 2012/13)
o Asset Replacement for period (2008/09 – 2012/13)</td></tr>
<tr><td>Source of Actual Information</td><td>Actual information for Static Var Compensators was sourced from Ellipse – Works Management Module (Project / Work Requests).</td></tr>
<tr><td>Methodology and assumption's used in relation to Actual Information</td><td>In order to obtain the information it was necessary for Ergon Energy to obtain the Works Requests for the project.
In doing so, it was assumed that there were no others replaced, this is a sound assumption as Ergon Energy only has four of these multi-million dollar pieces of equipment.</td></tr>
<tr><td>Use of Estimated Information</td><td>Ergon Energy has provided Estimated Information, in accordance with the AER's definition, in relation to the following variables:
▪ Expenditure by Asset Category (2008/09-2012/13) for:</td></tr>
</table>

Minimum Requirements	Ergon Energy Response [Other]
	o Current Transformers o Voltage Transformers o Capacitor Banks ▪ Asset replacement (2008/09-2012/13) for: o Current Transformers o Voltage Transformers o Capacitor Banks ▪ Asset failure (2008/09-2012/13) for: o Current Transformers o Voltage Transformers o Capacitor Banks o Static Var Compensator
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required relation to Expenditure By Asset Category (2008/09-2012/13), because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist. An estimation methodology has been developed in relation to providing expenditure data for individual asset categories It was not possible to use Actual Information, and an estimate is required in relation to ***ASSET REPLACEMENT*** And ***ASSET FAILURES*** because Ergon Energy's Asset Management system and processes did not allow adequate tracking of equipment once it is no longer in service.
How the estimate has been produced	***EXPENDITURE BY ASSET CATEGORY (2008/09-2012/13)*** In relation to expenditure for each asset category, Ergon Energy has developed the following estimation methodology: ***Plant Cost Allocation Method*** 1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are:

Activity Code	Description	Budget	Driver
53120	Corrective Reg Lines	OPEX	Maintenance
53150	Corrective Reg Subs	OPEX	Maintenance
54100	Forced Regulated Maintenance	OPEX	Maintenance
C2000	Network Refurbishment	CAPEX	Replacement
C2020	Ageing Asset Replacement	CAPEX	Replacement
C2130	Street Lighting Refurbishment	CAPEX	Replacement
C2050	Other Regulated System Capex	CAPEX	Other

Minimum Requirements	Ergon Energy Response [Other]
	2) Note Network Refurbishment above refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. All Expenditure reported is in line with the AER definition and relates to replacement of individual assets. Instances where no assets are replaced is insignificant and not reported separately.. 3) The number of Asset Replacements is determined by identification of all scrapped assets (in this class) and matching the previous location with new equipment to obtain the year replaced. Scrapped is a term used and is equivalent to removed from service. To identify these scrapped assets, data tags such as Deleted, Out of Service, Disposed and Scrapped, as well as a hierarchy group called scrapped were used. 4) That portion of Asset Replacement expenditure associated with the **Asset Group Substation Plant, (zone transformers, substation switchgear, protection and control equipment, and other)** has been determined from 'J Code' combinations. 5) Plant unit costs for representative items for each asset category have been obtained from Ergon Energy's current period contract rates for procurement of these items. 6) The "plant cost" for each financial year for each asset category is calculated by multiplying the number of replacements by the current cost of procurement of the representative item. 7) For the **Asset Group Substation Plant,** the expenditure for the financial year is calculated as the proportion of the ratio of the plant cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total expenditure costs are apportioned appropriately to the each asset category. 8) The ratio may be adjusted to enable correction for errors caused when the ratio of labour to material costs varies from the average, or low volumes of assets lead to significant purchase cost variation. The unit plant cost is reviewed by the SME to confirm that the value is consistent with their experience. For the few that were not consistent, the ratio is adjusted to bring the value in line with the Standard Estimate which is Ergon Energy's expectation of cost of install of this asset. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) ***Asset Replacement** (2008/09-2012/13)* In relation to Asset Replacement, Ergon Energy has developed an estimate based on

Minimum Requirements	Ergon Energy Response [Other]
	the following approach: ▪ Identification of all scrapped assets (in this class) and matching the previous location with new equipment to obtain the year replaced. ▪ Scrapped is a term used equivalent to removed from service and which is assumed to lead to REPLACED. To identify these scrapped assets, data tags such as Deleted, Out of Service, Disposed and Scrapped, as well as a hierarchy group called scrapped were used. In developing this estimate Ergon Energy has made the following assumptions: ▪ All scrapped assets are marked as such in the data source ▪ We were able to determine where the asset was when it failed. ***Asset Failure****(2008/09-2012/13)* In relation to Asset Failures, Ergon Energy has developed the following estimation methodology: ▪ FeederStat was used to identify an outage which is then attributed by some engineering knowledge and experience to a particular asset class. This data excludes extreme or atypical weather events. In developing this estimate Ergon Energy has assumed that all failures will lead to an outage. Ergon Energy considers that the best estimate has been provided for Asset Failures for substation plant categories on the basis that: a failure will lead to an outage, and the process for reporting these outages is consistently followed. It has not been possible from data available to exclude external events however Ergon Energy does not believe this has a material impact. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 8: SCADA Network Control Master Stations and Local Wiring

Minimum Requirements	Ergon Energy Response [SCADA Network Control Master Stations and Local Wiring]
Consistency with the requirements of	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

Minimum Requirements	Ergon Energy Response [SCADA Network Control Master Stations and Local Wiring]
the Notice	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Local wiring is not recorded as a separate asset in Ergon Energy's systems. Accordingly, all local wiring is considered part of the asset to which it is attached and therefore not reported separately. This is in line with the AERs Issue Register – Issue No. 15.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information for: ▪ Expenditure by Asset Category (2008/09-2012/13) ▪ Asset replacement (2008/09-2012/13) ▪ Asset failure (2008/09-2012/13) For: o Master Station Assets (Including local wiring for asset)
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required relation to ***Expenditure*** By Asset Category Or ***Asset Replacements*** (2008/09-2012/13), because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist. An estimation methodology has been developed in relation to providing expenditure data for individual asset categories. It was not possible to use Actual Information, and an estimate is required in relation to Asset Failures because Ergon Energy's Asset Management system and processes did not allow adequate tracking of equipment once it is no longer in service.
How the estimate has been produced	*Expenditure By Asset Category (2008/09-2012/13)* In relation to expenditure for each asset category, Ergon Energy has developed the following estimation methodology: ***Plant Cost Allocation Method*** 1) The total expenditure on Replacement (by financial year) is taken from the General Ledger using the two activity codes which align with this activity: These codes are C2000 Network Refurbishment C2020 and C2013 Ageing Asset Replacement. Network Refurbishment refers to the process of refurbishing a major part of the

Minimum Requirements	Ergon Energy Response [SCADA Network Control Master Stations and Local Wiring]
	network like a feeder or a zone substation by replacing its subordinate parts. 2) The number of Asset Replacements is determined by identification of all Replaced assets (in this class) through the use of secondary spreadsheets and databases developed by the secondary system teams. These spreadsheets and databases have become less accurate as Ergon Energy has attempted to move data into the corporate ERP – Ellipse, so far this has not been successful. 3) The total expenditure on the asset is extracted from the Ellipse inventory module, as is the total expenditure on materials. Ergon Energy considers that this ratio can be used to determine the proportion of other (non-material) costs as determined in step 1. 4) Using this ratio the total expenditure costs in activity codes C2000 and C2020 which include all direct costs can be apportioned appropriately to the asset. 5) The ratio may be adjusted to enable correction for errors caused when the ratio of labour to material costs varies from the average, or low volumes of assets lead to significant purchase cost variation. The unit plant cost is reviewed by the SME to confirm that the value is consistent with their experience. For the few that were not consistent, the ratio is adjusted to bring the value in line with the Standard Estimate which is Ergon Energy's expectation of cost of install of this asset. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit asset cost is reviewed and plant costs adjusted by the SME to ensure that the value is consistent with their experience. In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good proxy for the distribution of other costs associated with installing the asset. ***Asset Replacements*** In relation to expenditure for each asset category, Ergon Energy has developed the following estimation methodology: ▪ Asset replacements were sourced from Asset Management Control system's SCADA master system and ellipse. Ergon Energy considers the best estimate has been provided for Asset replacements as the SCADA master system contains the records and the Ellipse Asset management module contains asset attributes. In developing this estimate, it was assumed that the date installed was the year of manufacture. ***Asset Failures***

Minimum Requirements	Ergon Energy Response [SCADA Network Control Master Stations and Local Wiring]
	Ergon Energy has used a 5% failure rate based upon a sample of relay test-bench failures (available data at the time) for a 5 year period between 2008 and 2012. The population of relays in sample includes the three types in service (Electro-mechanical, Numerical and Static), **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 9: Field Devices and Local Wiring Assets

Minimum Requirements	Ergon Energy Response [Field Devices and Local Wiring Assets]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Local wiring is not recorded as a separate asset in Ergon Energy's systems. Accordingly, all local wiring is considered part of the asset to which it is attached and therefore not reported separately. This is in line with the AERs Issue Register – Issue No. 15.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables: ▪ Expenditure by Asset Category (2008/09-2012/13) ▪ Asset replacement (2008/09-2012/13) ▪ Asset failure (2008/09-2012/13) For:

Minimum Requirements	Ergon Energy Response [Field Devices and Local Wiring Assets]
	o Field Devices (Including local wiring for assets) o Remote Terminal Units (RTU) o Protection Relays (RELAY)
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to ***Expenditure***, ***Asset Replacement*** And ***Asset Failure***. ***Asset (Protection Relay) Replacements Volumes*** It was not possible to use Actual Information, and an estimate is required in relation to replacements because: ▪ Ellipse business rules do not include the requirement of recording secondary system asset history or traceability, ▪ The PDS (Protection Database System) is designed to record protection settings and produce change work orders therefore the date of settings change is accurate but the attributes of the relay are not stored in PDS. ▪ Current records are in secondary spreadsheets and databases developed by the secondary system teams. These spreadsheets and databases have become less accurate as Ergon Energy has attempted to move data into the corporate ERP – Ellipse, so far this has not been successful. ***Asset Failure Volumes*** It was not possible to use Actual Information, and an estimate is required in relation to relay failure rates because Ellipse business rules do not include the requirement of recording secondary system asset failures. ***Expenditure By Asset Category*** It was not possible to use Actual Information, and an estimate is required in relation to, the quantity of data and level of detail required for the “Expenditure” for each of 5 financial years in Table 2.2.1 represented a significant challenge for Ergon Energy. The corporate ERP and associated processes were not envisioned and configured with the level of detail now requested by the AER in mind. By and large, processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced simply does not exist.
How the estimate has been produced	In relation to ***Asset (Protection Relay) Replacements Volumes*** Ergon Energy has developed an estimate based on the following approach ▪ All local wiring is considered part of the asset to which it is attached. ▪ Protection Relays: PDS data indicating a replace have been used to identify relay Replacements ▪ Records in transition have been completed and have been distributed throughout the for-mentioned period according to their finalised date. In developing this estimate, Ergon Energy has made the following assumptions: ▪ PSR (Protection Setting Request) records and PDS data is relatively accurate, however asset information is not routinely updated and is not designed for asset

Minimum Requirements	Ergon Energy Response [Field Devices and Local Wiring Assets]
	condition and history. Thus, extracting replacement and installation asset data is labour intensive and requires analysis to identify appropriate asset records for replacement and will retain a certain level of accuracy, This analysis has not been performed previously but has been performed to obtain the replacement volumes required by the Category Analysis RIN. Ergon Energy considers the best estimate has been provided for relay replacement on the basis that: ▪ PDS's depository of PSR records hold one of the few sources of information for replacement information, ▪ PDS replacement data (via PSRs) is cross-referenced with completed relay replacement programs under Capital works. ***RTU AND AFLC REPLACEMENTS*** In relation to relay failures Ergon Energy has developed an estimate based on the following approach: ▪ RTU (Remote Terminal Units) replacements were sourced from Asset Management Control systems' internal RTU and AFLC (Auto Frequency Load Control) spreadsheets, SCADA master system and ellipse. Ergon Energy considers the best estimate has been provided for relay replacement on the basis that the secondary system team maintains the spreadsheets manually and are therefore the best information on these assets. ***Relay Failures*** In relation to relay failures Ergon Energy has developed an estimate based on the following approach: ▪ Use of failure rate of 5% of all replacements as failures, In developing this estimate, Ergon Energy has made the following assumptions: ▪ Relay failures shall be a subset of relay replacements, ▪ Relay failure shall be defined as entire relay replacement due to a critical failure and not a partial failure. ▪ Based failure rate on the study of available relay test records. Ergon Energy considers the best estimate has been provided for relay failures on the basis that: ▪ Reliance on available sample data study reflected a 4 to 14% of relay test failure rate based. The 5% was based upon a weighted average of relay types and ages of failed assets. ***Expenditure By Asset Category (2008/09-2012/13)*** ***Plant Cost Allocation Method*** 1) The total expenditure on Replacement (by financial year) is taken from the General Ledger using the two activity codes which align with this activity: These codes are C2000 Network Refurbishment C2020 Ageing Asset Replacement and C2130 Street Lighting Refurbishment. Network Refurbishment refers to the

Minimum Requirements	Ergon Energy Response [Field Devices and Local Wiring Assets]
	process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. 2) The number of Asset Replacements is determined by identification of all Replaced assets (in this class) through the use of secondary spreadsheets and databases developed by the secondary system teams. These spreadsheets and databases have become less accurate as Ergon Energy has attempted to move data into the corporate ERP – Ellipse, so far this has not been successful. 3) The asset Material cost is determined from the purchasing contracts in the Ellipse inventory system. 4) This material cost is multiplied by the number of assets determined in step 2. 5) The result is adjusted to correct for errors caused when the ratio of labour to material costs varies from the average, or low volumes of assets lead to significant purchase cost variation. The unit plant cost is reviewed by the SME to confirm that the value is consistent with their experience. For the few that were not consistent, the ratio is adjusted to bring the value in line with the Standard Estimate which is Ergon Energy's expectation of cost of install of this asset. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly Expenditure on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit plant cost is reviewed and plant costs adjusted by the SME to ensure that the value is consistent with their experience. In the absence of actual data, Ergon has proportioned the costs for substation plant and adjusted the values to approximate the Standard estimate values, whilst still totalling to the actual expenditure for substation replacement. **NOTE:** It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed: ▪ There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years ▪ When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost. Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 10: Communication and Local Wiring Assets

Minimum Requirements	Ergon Energy Response [Communication and Local Wiring Assets]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Local wiring is not recorded as a separate asset in Ergon Energy's systems. Accordingly, all local wiring is considered part of the asset to which it is attached and therefore not reported separately. This is in line with the AERs Issue Register – Issue No. 15.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Use of Estimated Information	Ergon Energy has provided Estimated information, in accordance with AER's definition for ▪ Expenditure ▪ Asset Replacements Volume ▪ Asset Failure Volume For: ▪ Communications Network Assets ▪ Communications Site Infrastructure ▪ Communications Linear Assets
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information for Expenditure By Asset Category (2008/09 TO 2012/13) as the processes and systems within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes and budgetary allocations. Thus the ability to directly access the individual costs of each asset replaced does not exist. An estimation methodology was used to provide expenditure data for individual asset classes. Local wiring is included with the asset for which it was used. It was not possible to use Actual Information For Asset Replacements Or Failure Volumes (2008/09 TO 2012/13) because Ellipse business rules do not include the requirement of recording asset history or traceability.
How the estimate has been produced	In relation to ***Expenditure By Asset Category (***2008/09 TO 2012/13), Ergon Energy developed the following estimation methodology: ▪ Manually identify number of replacements in each asset category by excluding

erroneous data that could not clearly be allocated to a communications asset category.

- Filter the data per financial year and allocate the expenditure based on that filter, making the assumption the asset was replaced the financial year it was purchased.
- 100% of the P25 mobile radio replacement program was incorrectly allocated to the activity code C2050 – Other Regulated System Capex. Ergon Energy identified that this should have been allocated to activity code C2020 - Ageing Asset Replacement.
- 25% of the Ubinet project data based on SME knowledge against replacements and expenditure. This was not previously reported in past Annual Performance RIN's. The total dollar impact is an increase of $34.57M.
- The portion of 25% of the overall Ubinet project expenditure has been estimated to be allocated to REPEX through independent consultation with 3 SME's that worked closely on the project. At the time of the project these SME's were the Project Manager, Network Architect and Telecommunication Network & Design Manager combined they have around 80yrs experience in the industry. They determined the allocation of 25% by having an in-depth knowledge of the existing Ergon Network prior to the commencement of the project. As the project moved forward it became evident that aged asset replacement would be a more viable option than the creation of new sites and that is the direction a portion of the project then took. At the time of collecting the data for RIN, the SME's consulted in relation to the Ubinet Project all came back with the figure of 25%.

In developing this estimate Ergon Energy has assumed that all sites are equal and no particular exemptions or additions have been made.

Ergon Energy considers the best estimate has been provide for communications assets on the basis that Ergon Energy's systems and processes have not recorded this information in the past. The information provided has been validated by experienced Engineers.

NOTE: It should be noted that there are inherent limitations with the weighted plant method that need to be disclosed:

- There can be a lag between when stores are issued, items are replaced and expenditure incurred. This can result in variances in the unit replacement cost over the five years
- When replacement quantities are low and not consistent from year to year, and stores costs are high, the weighted allocation method does not allow for the expenditure to be smoothed out to create a consistent unit replacement cost.

Nevertheless, the unit replacement cost is considered consistent with Ergon Energy's replacement costs when averaged over multiple years.

Table 2.2.2 - Descriptor Metrics

Table 11: Poles, Overhead Conductors and Underground Cables

Minimum Requirements	Ergon Energy Response [Poles, Overhead Conductors and Underground Cables]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. Ergon Energy does not have “CBD” Poles, Conductor or Cable assets.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category.
Methodology and assumption’s used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables: ▪ Replacements
Why is it not possible to use Actual Information, and why an estimate is required	It is not possible to use Actual Information and an estimate is required in relation to Asset Replacements because the assets do not have these categories attached.
How the estimate has been produced	Asset volume in commission by Urban, Rural Short And Rural Long classifications for poles, conductor and cable is sourced from Ergon Energy’s Smallworld GIS. Smallworld GIS data was also used to source the split of overhead conductors by material type. In order to obtain Asset Volumes Currently In Commission, it was necessary for Ergon Energy to sum all equipment on each Feeder, as the classifications are applied at the feeder level. In doing so it is assumed that Ergon Energy’s classification of “Transmission” sits within “Rural Long”. In relation to Replacements, Ergon Energy has developed an estimate based on an approach whereby the ratio of Urban, Rural And Rural Long asset volumes and material type is used to assign a portion of the replacements to each category.

Table 12: Transformers

Minimum Requirements	Ergon Energy Response [Transformers]
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for TOTAL MVA [currently in commission].
Source of Actual Information	Actual Information for TOTAL MVA [currently in commission] was sourced from ▪ For Zone transformers, MVA ratings have been sourced from Ergon Energy's corporate ERP – Ellipse (Asset Management Module) nameplate data. ▪ For Distribution Transformers, nameplate rating has been obtained from Ergon Energy's corporate ERP – Smallworld GIS data.
Methodology and assumption's used in relation to Actual Information	***TOTAL MVA [currently in commission***] ▪ For Substation transformers, MVA ratings have been sourced from Ergon Energy's corporate ERP- Ellipse. The nameplate data is summated. ▪ For Distribution Transformers, nameplate rating has been obtained from the Smallworld GIS "slot" rating. ▪ Total MVA capacity currently in commission is then obtained by adding Power transformer data to Distribution transformer data.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables: ▪ TOTAL MVA DISPOSED OF ▪ TOTAL MVA REPLACED for all period 2008/09 to 2012/13 ▪ TOTAL MVA [replaced in current year]
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information. And an estimate is required in relation to TOTAL MVA DISPOSED OF, because there is a large time lapse when transformers are sent to be tested for possible repair and then are disposed. It was not possible to use Actual Information. And an estimate is required in relation to TOTAL MVA REPLACED, because there is no direct record in our system of when an asset is replaced, or log of when it is replaced. It was not possible to use Actual Information. And an estimate is required in relation to TOTAL MVA [currently in commission], because data is obtained from a system that is not the master asset data.
How the estimate has been	***TOTAL MVA DISPOSED OF***

Minimum Requirements	Ergon Energy Response [Transformers]
produced	***TOTAL MVA REPLACED for*** all period 2008/09 to 2012/13 ***TOTAL MVA [replaced*** in current year] In relation to TOTAL MVA, Ergon Energy has developed an estimate based on the following approach ▪ For Substation transformers, MVA ratings have been sourced from Ergon Energy's corporate ERP- Ellipse. The nameplate data is summated. ▪ For Distribution Transformers, nameplate rating has been obtained stores issues data. The nameplate rating is contained within the text description of distribution transformers in the inventory register. A temporary data table was produced by reading each distribution transformer description and giving it a rating. ▪ Total MVA capacity replaced each year is then obtained by adding Power transformer data to Distribution transformer data In developing this estimate, Ergon Energy assumed those transformers that are installed are booked to the correct code. Ergon Energy considers this the best estimate has been provided for these TOTAL MVA as the inventory system is well maintained and has rigorous processes and the manual searching was vigorous and included input from data professionals and engineers.

Category Analysis RIN Basis of Preparation

Template 2.3 Augex Project Data

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.3 Augex Project Data of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.3 Augex Project Data (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.3 Augex Project Data, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

Furthermore, the below additional requirement/s were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation. Responses to these requirements are made as attachment/s to this Basis of Preparation.

Table 1: Attachment/s to Basis of Preparation for Template 2.3 Augex Project Data

Notice Reference	Requirement	Attachments
7.1(c)(i), and 7.3(c)(i)	▪ Where expenditure has been reported in real $2012/13, provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.	EECL 0913 CARIN_T2.3 AGX A1

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.3 Augex Project Data (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.3 Augex Project Data

Table 2.3.1 Augex Asset Data – Subtransmission Substations, Switching Stations and Zone Substation

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.3, Table 2.3.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported), excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type. Ergon Energy has not included information for gifted assets, and no augmentation expenditure in relation to connections has been included in template 2.3. Projects were included for augmentation and the addition of equipment within sub-transmission substations i.e. monitoring and communication equipment under table 2.3.1, although there were no additional capacity (MVA) added to substations. These projects were therefore included as non-material projects. Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). The calculations of capacity are based on normal conditions and in response to paragraph 7.1(b), Ergon Energy defines "normal conditions": ▪ "When assessing compliance with the network security criteria it is important to select the correct plant ratings for each scenario. It should be noted that, the Normal Cyclic Capacity (NCC) of equipment applies during system normal conditions i.e. where all network elements are in service." With regards to Related Party expenditure: ▪ Within the Ergon Energy group, the parent entity Ergon Energy Corporation Limited (EECL) maintains controlling interest over three reporting entities. These include Ergon Energy Queensland Pty Limited (EEQ) and Ergon Energy Telecommunications Pty Limited (EET) which are both 100% owned, and a jointly controlled entity SPARQ Solutions Pty Ltd (SPARQ) where Ergon Energy maintains

Minimum Requirements	Ergon Energy Response
	a 50% ownership interest. EEQ is a non-competing electricity retailer; EET is a wholesale telecommunication service provider; and SPARQ is an information, communications and technology service provider. ▪ EECL provides management services to its subsidiaries. Accordingly, EEQ and EET do not have their own management structures. EECL pays SPARQ a charge in accordance with service level agreements which is captured as a corporate overhead. ▪ EECL is subject to common control as a Queensland Government Owned Corporation (GOC), with all shares held by shareholding Ministers on behalf of the State of Queensland and transacts with other State of Queensland controlled entities. However, the Queensland Government and State of Queensland controlled entities are not considered related parties for the purposes of the CA RIN due to the specific exclusion of government departments in the definition. ▪ Accordingly, Ergon Energy did not identify any Related Parties contract expenditure in relation to Augmentation projects and Related Party Margins is recorded as "zero". ▪ All Non Related Party Contracts are calculated as the Total Contractors expenditure. Expenditure in 'All related party contracts' and 'All non-related party contracts' columns do not contribute to the total direct expenditure on an augex project ('Total direct expenditure') as required. ▪ Finally, all contract expenditure for augex projects under the 'All related party contracts' and 'All non-related party contracts' columns were allocated to the appropriate 'Plant and equipment" expenditure and "Other Expenditure". Ergon Energy has considered and complied with clarifications provided by the AER on issues related to template 2.3 and relevant to Ergon Energy. With regards to instructions specific to Table 2.3.1 (on regulatory template 2.3), Ergon Energy notes: ▪ Ergon Energy has reported all expenditure data for Augex in Table 2.3.1 in real $2012/13. Nominal dollars has been converted to real dollars using actual CPI rates (Mar-Mar) for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS). Calculations have been provided as Attachment 1: Nominal to real values Template 2.3. ▪ Ergon Energy only included data in table 2.3.1 for augmentation works where project close occurred within the years specified and did not include data for works where the project closed after the years specified but incurred expenditure prior to this date. ▪ Augmentation project**s** on a subtransmission substation, switching station and zone substation owned and operated by Ergon Energy

Minimum Requirements	Ergon Energy Response
	with greater than or equal to $5 million (nominal) cumulative expenditure over the life of the project where project close occurred at any time in the years specified**,** have been reported separately in table 2.3.1. ▪ In this regard, both direct and indirect (overheads) costs were included in determining the cumulative expenditure over the life of a project as per the AER clarification however, only the direct cost was reportable in table 2.3.1. ▪ Projects with less than $5 million nominal expenditure over the life of the project where project close occurred at any time in the years specified have been consolidated into the expenditure figures in the penultimate row of table 2.3.1. ▪ All augmentation work on substations in Ergon Energy's network was included in table 2.3.1. There were no substations operating at notional transmission voltages. ▪ Each row in table 2.3.1 represents an individual substation and project. Ergon Energy does not conduct work on more than one substation per one project. Ergon Energy uses a parent project with child projects underneath the parent project to structure projects. The highest level (parent project) is the substation with all the components relevant to that one substation raised as child projects under the parent project. ▪ No substation augmentation projects in table 2.3.1 are related to other projects, including other tables in template 2.3. ▪ Ergon Energy has provided additional information in relation to projects where "Other – specify" were selected in **Appendix A: Template 2.3 Table 2.3.1 Other – specify.** ▪ The substation ID's provided in table 2.3.1 represents Ergon Energy's unique substation identification number and the project ID is Ergon Energy's project number allocated within the Ellipse operating system. ▪ The primary trigger was selected within the drop down list provided. None of the projects listed in table 2.3.1 have any secondary triggers to be disclosed. Where 'Other – specify" were selected, the triggers are described in **Appendix A: Template 2.3 Table 2.3.1 Other – specify** ▪ Voltages on substations listed in table 2.3.1 were entered in the format xx/xx or xx/xx/xx, reflecting the primary, secondary and tertiary voltages. ▪ Ergon Energy has complied with the required in put 'Pre' and 'Post' substation ratings as per paragraph 7.2 (k) ▪ Ergon Energy only included procurement cost under 'Total expenditure' for transformers, switchgear, capacitors and other plant items. Installation costs have been reported separately in each table.

Minimum Requirements	Ergon Energy Response
	▪ With regards to Land and Easement expenditure: ▪ Total direct expenditure does not include any expenditure for land or easements. ▪ The land and easement acquisition for augmentation works on substation ID82647119 was captured under a separate project and therefore disclosed as a separate line item in table 2.3.1. Furthermore, Ergon Energy input all expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively, including legal, stamp duties and cost of purchase or easement compensation payments. Where contractor payments were not coded to the Land & Easement expense element the costs were included under "Installation Labour" or "Other Plant". ▪ Ergon Energy calculated 'Other Plant' expenditure as the total cost of all equipment and materials booked to the relevant project less estimated cost for Transformers, Switchgear and Capacitors.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for the following variables in Template 2.3, Table 2.3.1 which requires expenditure data on a project close basis, for all initial regulatory years (2008/09 to 2012/13). ▪ Installation Volume ▪ Installation (Labour) Expenditure ▪ Civil Works Expenditure ▪ Other Direct Expenditure ▪ Years Incurred ▪ All Non Related Party Contracts ▪ Land Purchase ▪ Easements ▪ Non Material Projects – Total Direct Expenditure ▪ Non Material Projects – Years Incurred ▪ Non Material Projects – Land Purchase ▪ Non Material Projects – Easements ▪ Voltage (KV) ▪ Substation Rating Normal Cyclic (MVA) ▪ Substation Rating N-1 Emergency (MVA) ▪ Transformers – Units added ▪ Transformers – MVA Added ▪ Switchgear – units added ▪ Capacitors – MVAR added

Minimum Requirements	Ergon Energy Response
	The majority of Augmentation projects incurred cost over more than one financial year and in some cases over a number of financial years. Projects with project close dates within the reporting period (2008/09 to 2012/13) would have had cost incurred before the reporting period (pre 2008/09), which was included in expenditure disclosed in table 2.3.1.
Source of Actual Information	Actual Information for the financial variables was sourced from Ergon Energy's Ellipse operating system. Where possible, cost for projects that closed within the reporting period (2008/09 to 2012/13), but incurred costs prior to September 2006 were sourced from the Oracle operating system, the legacy system. The following actual information for non-financial variables was sourced from Smallworld GIS data using search functions based on the equipment class to extract the data: ▪ Transformers – Units added ▪ Transformers – MVA Added ▪ Switchgear – units added ▪ Capacitors – MVAR added The following information was taken from planning reports: ▪ Voltage (KV) ▪ Substation Rating Normal Cyclic (MVA) ▪ Substation Rating N-1 Emergency (MVA)
Methodology and assumption's used in relation to Actual Information	Reports were run from the Ellipse operating system which listed all projects closed within regulatory years 2009 – 2013 under the Augex financial activity codes C2010, C2030, C2040 and C2050 – the RIN C2040 report and the RIN C2010, C2030, C2050 report, excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type. These reports included all Ergon Energy augmentation projects, not only those related to Subtransmission Substations, Switching Stations and Zone Substations. The project list was filtered to include only those projects relating to Subtransmission Substations, Switching Stations and Zone Substations by analysing the project j-codes (asset classification codes) and extracting Subtransmission Substations, Switching Stations and Zone Substations projects. The extracted substation project list reported each project and their total cumulative expenditure over the life of the project, broken down by direct costs and overheads as well as their total annual expenditure as incurred (excluding overheads). Each project with a total (whole of life) expenditure of equal or greater than $5 million (nominal, inclusive of direct and overhead costs) was reported as a separate project in the RIN

Minimum Requirements	Ergon Energy Response
	template. Those projects less that $5 million were labelled as a non-material project to be consolidated into a single substation line item in table 2.3.1. No projects with a total (whole of life) expenditure of equal or greater than $5 million (nominal, inclusive of direct and overhead costs) was identified through the RIN C2010, C2030, C2050 report. All projects identified through the RIN C2010, C2030, C2050 report had a total expenditure less than $5 million and was therefore included as non-material projects. The report also provided cost per project for the following expenditure categories: Materials, Contractor cost, Labour cost, Purchases, Stores, Other direct cost. Further detailed expenditure reports were run from Ellipse on each material project providing details of each expense booked to the project. Where possible, cost for projects that closed within the reporting period (2008/09 to 2012/13), but incurred costs prior to September 2006 were sourced from the Oracle operating system. A detailed expense report was run for each of the identified material projects that had cost incurred before September 2006 from the Oracle system and cost analysed and categorised per expense type. In order to report the information in the required expense categories per table 2.3.1, Ergon Energy applied the following methodology and assumptions to the data presented in the RIN C2040 and RIN C2010, C2030, C2050 reports and the data extracted from Oracle: **Installation (Labour) Volume** was calculated as the sum of Total Labour Hours reported from Oracle, labour hours identified from RIN C2040 report and labour hours which was identified by searching each project's cost within Ellipse for Ergon Energy employees for each project. **Installation (Labour) Expenditure** was calculated as the Sum of Contract Labour and Internal Labour as per the RIN C2040 report and Oracle reports, less civil works labour identified through detailed analysis of labour expenditure for each project. **Civil Works Expenditure** was calculated on the Asset apportionment percentage for Substation Buildings on the Incurred To Date Costs (excluding overheads). There is no report available to provide this information as civil costs fall to the contractor expense elements. After reviewing detailed contractor and purchase transactions for Projects in Ellipse reports we could not identify with accuracy civil works costs. We therefore used the BPU apportionment for Substation buildings (percentage of project cost allocated to Substation buildings) and applied this percentage to the Total cumulative costs (excluding overheads) of the individual projects and input as civil works cost into table 2.3.1. **Other Direct Expenditure** was calculated as the Total Other Costs as

Minimum Requirements	Ergon Energy Response
	per the RIN C2040 report, less the sum of Land and Easements. Total Other Cost as per RIN C2040 report includes Land and Easement cost. Other Costs includes:- ▪ Capital Interest ▪ Computer ▪ Other ▪ Transport Internal ▪ Transport External ▪ Travel & Accommodation **Years Incurred** was sourced from the RIN C2040 report. Projects carried from the legacy system (Oracle) (prior to September 2006) are reported with the commencement year of 2007. **Related Party Margins** is recorded as “zero”; Ergon Energy did not identify any Related Parties contract expenditure in relation to Augmentation projects. **All Non Related Party Contracts** is disclosed as the Total Contractors expenditure as per the RIN C2040 report. **Land Purchase and Easements** cost is included as Other Costs in the RIN C2040 report and Ellipse. Land and Easement cost was therefore calculated by running an Ellipse report for activity C2040 (augmentation) by expense element 6160 (Easement/Land), the Land & Easements C2040000006160 Report. This report provided the total land and easement cost per project. It was also confirmed that Oracle cost was brought over to Ellipse as Land and Easement to the correct expense element. To split the cost between Land Purchase and Easements, we used the BPU apportionment for Land (L5) (percentage of project cost allocated to Land) and Easements (L9) (percentage of project cost allocated to Easement) and applied this percentage to the total Land and Easement expenditure as per Ellipse report Land & Easements C2040000006160 for each project and input as Land purchase or Easements in table 2.3.1. **Non Material Projects – Total Direct Expenditure** was sourced from the RIN C2040 and RIN C2010, C2030, C2050 reports. The total cumulative expenditure (excluding overheads) over the life of the projects identified as non- material projects as per the RIN C2040 and RIN C2010, C2030, C2050 reports was listed as Total Direct Expenditure for Non Material projects in table 2.3.1. **Non Material Projects – Years Incurred** was sourced from the RIN C2040 and RIN C2010, C2030, C2050 reports. Projects carried over from the legacy system (Oracle) (prior to September 2006) are reported with the commencement year of 2007. **Non Material Projects - Land Purchase and Easements** was

Minimum Requirements	Ergon Energy Response
	calculated by applying the same methodology as for Land Purchase and Easements for material projects described above. The following actual Information for non-financial variables was sourced from Smallworld GIS data using search functions based on the equipment class to extract the data: ▪ Transformers – Units added ▪ Transformers – MVA Added ▪ Switchgear – units added ▪ Capacitors – MVAR added In order to provide the information required in table 2.3.1, it was necessary for Ergon Energy to run searches on data for each individual substation for the required data fields. Data was extracted by running reports on each required substation using the substation number as the limit for the search. Equipment classes were searched to return the number of individual assets in each class that are child assets of the parent substation number. Where there is a zero input it means that there were zero assets in that class for the parent asset being reported on. Ergon Energy also consulted system operating diagrams and substation construction drawings to confirm data and determine the sections associated with substation upgrades. In doing so, it was assumed that the number of switches for Project ID CPMNS00567 (the construction of skid mount sub-stations) was the same as our standard design and no alterations were made when they were installed at specific locations. The following information was taken from planning reports on each individual project: ▪ Voltage (KV) ▪ Substation Rating Normal Cyclic (MVA) ▪ Substation Rating N-1 Emergency (MVA) **<u>Converting nominal to real values</u>** Ergon Energy has reported all expenditure data for Augex in Table 2.3.1 in real $2012/13. Nominal dollars has been converted to real dollars using actual CPI rates (Mar-Mar) for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS). The RIN C2040 and RIN C2010, C2030, C2050 reports provided a split of total cumulative cost (excluding overheads) in nominal values for each year in which cost was incurred. Ergon Energy applied the relevant CPI rate for each specified year in which cost was incurred to convert the nominal values to real values. The following assumptions were applied in converting nominal values to real values:

Minimum Requirements	Ergon Energy Response
	Land & Easements – The financial year in which land and easements costs were incurred was not specified within reporting data. The assumption that land and easement costs have been incurred first was applied to convert land and easement cost to real values. **Expenditure categories -** Cost incurred by financial year cannot be split by expense category. Total project cost nominal values per year incurred have therefore been converted to real values and total real values apportioned into expenditure categories based on the nominal values allocated to each expense category. **Expenditure incurred prior to September 2006 -** Cost for projects that closed within the reporting period (2008/09 to 2012/13), but incurred costs prior to September 2006 was assumed to have fallen in 2006/07 financial year.
Use of Estimated Information	Ergon Energy has used Estimated Information in relation to the following Plant and Equipment expenditure variables, for regulatory years 2008/09 to 2012/13: ▪ Transformers; ▪ Switchgears; and ▪ Capacitors; and ▪ Other Plant Expenditure.
Why is it not possible to use Actual Information, and why an estimate is required	An estimate was required in relation to Transformer expenditure as transformers of this capacity are purchased externally and not through stores and requisitioning information was limited in detail. It was therefore not possible to identify expenditure related to transformers. Many of these projects costs also fell in Ergon Energy's legacy system (Oracle) and it was not possible to extract data in detail. Ergon Energy extracted stores requisition data to identify Switchgear expenditure per project through the RIN Reporting Requisitioning Data (Ellipse report). The data however did not detail individual project transactions on all projects. An estimate was required in relation to Switchgear expenditure. An estimate was required in relation to Capacitor Expenditure as these items are purchased externally and not through stores and requisitioning information was limited in detail. It was therefore not possible to identify expenditure related to capacitors. Many of these project costs also fell in Ergon Energy's legacy system (Oracle) and it was not possible to extract data in detail. Other Plant Expenditure was categorised as an estimate as it was calculated as the Total Materials and Purchases less estimated numbers for Transformers, Switchgear and Capacitors.
How the estimate has been produced	**Transformer Expenditure** In relation to transformer expenditure, Ergon Energy has developed an estimate based on a review and identification of transformer purchase

Minimum Requirements	Ergon Energy Response
	transactions on three projects through the review of Ellipse and legacy system data. Transaction data was used to calculate an average price per unit and MVA added. The average percentage per unit and per MVA were exact across the three projects, Ergon Energy therefore considered this to be a suitable average to apply to estimate Transformer expenditure. Ergon Energy considers that the best estimate has been provided for Transformer Expenditure on the basis that: ▪ There was limited sampling in the RIN Reporting Requisitioning Data available; ▪ Data was limited in legacy systems which made extracting transformer information impossible; and ▪ Average price based on percentage per unit and percentage per MVA was exact for the samples made. **Switchgear Expenditure** In relation to Switchgear Expenditure Ergon Energy has developed an estimate based on the following approach: Identified all Switchgear items purchased through internal stores as per the RIN Reporting Data Requisitioning Data Report (Ellipse). This data was used to calculate an average price per unit based on the number of units reported per dollar value. The average price per Switchgear unit was then applied to the number of units added to calculate the Switchgear expenditure reported. In developing this estimate, Ergon Energy notes the actual data was not suitable due to the unavailability of detailed information on switchgear expenditure as per the RIN Reporting Requisitioning Data Report. Ergon Energy do not have an expense category that details switchgear cost. Ergon Energy considers the best estimate has been provided for Switchgear Expenditure on the basis that a larger sample more accurately calculates a better average price per unit. **Capacitor Expenditure** In relation to Capacitor Expenditure Ergon Energy has developed an estimate having identified two transactions through current system sources, from which data was used to calculate an average price based on MVA added. In developing this estimate, Ergon Energy notes it was only able to identify transactions with capacitor information on two projects through the RIN Reporting Requisitioning Data Report and yet five projects had capacitors added. It was considered that the average price per MVA would need to be applied as per the transformer sampling for consistency. Ergon Energy considers the best estimate has been provided for Capacitor Expenditure given the limited availability of data and time permitted to prepare the RIN information.

Minimum Requirements	Ergon Energy Response
	Other Plant Expenditure Other Plant Expenditure was calculated as the Total Materials and Purchases as per the RIN C2040 report, less estimated cost for Transformers, Switchgear and Capacitors. **Converting nominal to real values** Expenditure categories - Cost incurred by financial year cannot be split by expense category. Total project cost nominal values per year incurred have therefore been converted to real values and total real values apportioned for transformers, switchgear, capacitors and other plant expenditure based on the nominal values allocated to each of these expense categories.

Table 2.3.2 Augex Asset Data – Subtransmission Lines

Table 2: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.3, Table 2.3.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy have considered and complied with clarifications provided by the AER on issues related to template 2.3 and relevant to Ergon Energy. Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported). Ergon Energy has not included information for gifted assets, and no augmentation expenditure in relation to connections has been included in template 2.3. Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). The calculations of capacity are based on normal conditions and in response to paragraph 7.1(b), Ergon Energy defines "normal conditions": ▪ "When assessing compliance with the network security criteria it is important to select the correct plant ratings for each scenario. It should be noted that, the Normal Cyclic Capacity (NCC) of equipment applies during system normal conditions i.e. where all network elements are in service." With regards to Related Party expenditure:

Minimum Requirements	Ergon Energy Response
	▪ Within the Ergon Energy group, the parent entity Ergon Energy Corporation Limited (EECL) maintains controlling interest over three reporting entities. These include Ergon Energy Queensland Pty Limited (EEQ) and Ergon Energy Telecommunications Pty Limited (EET) which are both 100% owned, and a jointly controlled entity SPARQ Solutions Pty Ltd (SPARQ) where Ergon Energy maintains a 50% ownership interest. EEQ is a non-competing electricity retailer; EET is a wholesale telecommunication service provider; and SPARQ is an information, communications and technology service provider. ▪ EECL provides management services to its subsidiaries. Accordingly, EEQ and EET do not have their own management structures. EECL pays SPARQ a charge in accordance with service level agreements which is captured as a corporate overhead. ▪ EECL is subject to common control as a Queensland Government Owned Corporation (GOC), with all shares held by shareholding Ministers on behalf of the State of Queensland and transacts with other State of Queensland controlled entities. However, the Queensland Government and State of Queensland controlled entities are not considered related parties for the purposes of the CA RIN due to the specific exclusion of government departments in the definition. ▪ Accordingly, Ergon Energy did not identify any Related Parties contract expenditure in relation to Augmentation projects and Related Party Margins is recorded as “zero”. ▪ All Non Related Party Contracts are calculated as the Total Contractors expenditure. Expenditure in ‘All related party contracts’ and ‘All non-related party contracts’ columns do not contribute to the total direct expenditure on an augex project (‘Total direct expenditure’) as required. ▪ Finally, all contract expenditure for augex projects under the ‘All related party contracts’ and ‘All non-related party contracts’ columns were allocated to the appropriate ‘Plant and equipment” expenditure With regards to instructions specific to Table 2.3.2 (on regulatory template 2.3), Ergon Energy notes: ▪ Ergon Energy has reported all expenditure data for Augex in Table 2.3.2 in real $2012/13. Nominal dollars has been converted to real dollars using actual CPI rates (Mar-Mar) for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS). Calculations have been provided as Attachment 1 to this Basis of Preparation. ▪ Ergon Energy only included data in table 2.3.2 for augmentation works where project close occurred within the years specified and did not include data for works where the project closed after the

Minimum Requirements	Ergon Energy Response
	years specified but incurred expenditure prior to this date. ▪ Augmentation project on a subtransmission line owned and operated by Ergon Energy with greater than or equal to $5 million (nominal) cumulative expenditure over the life of the project where project close occurred at any time in the years specified have been reported separately in table 2.3.2. Both direct and indirect (overheads) cost was included in determining the cumulative expenditure over the life of a project as per AER clarification. Only direct cost was included in table 2.3.2. ▪ Projects with less than $5 million nominal expenditure over the life of the project where project close occurred at any time in the years specified have been consolidated into the expenditure figures in the penultimate row of table 2.3.2. ▪ All augmentation work on subtransmission lines in Ergon Energy's network was included in table 2.3.2. There were no augmentation projects on lines or cables operating at notional transmission voltages that closed during the years specified. ▪ Each row in table 2.3.2 represents data for all circuits of a given voltage subject to *augmentation* works under the Project ID. Where an augmentation project applied to two or more circuits of the same voltage, Ergon Energy entered data for all the circuits in one row. There were no projects identified where an augmentation project applied to more than one circuits of different voltages. ▪ No subtransmission lines augmentation projects in table 2.3.2 are related to other projects, including other tables in template 2.3. ▪ Ergon Energy did not select "Other – specify" for any projects disclosed in table 2.3.2. ▪ The line ID's provided in table 2.3.2 is Ergon Energy's unique line identification number allocated within the Ellipse operating system. ▪ The project ID's provided in table 2.3.2 is Ergon Energy's unique project identification number allocated within the Ellipse operating system. ▪ The primary trigger was selected within the drop down list provided. None of the projects listed in table 2.3.2 have any secondary triggers to be disclosed. Ergon Energy did not choose "Other – specify" for any projects disclosed in table 2.3.2. ▪ "Km added" disclosed in table 2.3.2 is the gross addition of the relevant line or cable added as a result of the augmentation work and any line or cable removed was not netted off against the km's added. ▪ Ergon Energy only included procurement cost under 'Total expenditure' for poles/towers, including civil works. Installation costs have been reported separately in each table. ▪ Ergon Energy only included procurement cost under 'Total

Minimum Requirements	Ergon Energy Response
	expenditure' for lines, cables and 'other plant item'. Installation costs have been reported separately in each table. ▪ Civil works expenditure related to poles/towers was not included under 'Total expenditure' for civil work, but included under Poles/Towers Expenditure. ▪ With regards to Land and Easements, Ergon Energy notes that: ▪ Total direct expenditure does not include any expenditure for land purchases or easements. ▪ Ergon Energy did not record any land and easement projects and/or expenditure as separate line items in table 2.3.2. ▪ Ergon Energy input all expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively, including legal, stamp duties and cost of purchase or easement compensation payments.Where contractor payments were not coded to the Land & Easement expense element,the costs were included under "Installation Labour" or "Other Plant". ▪ Ergon Energy calculated 'Other Plant' expenditure as the total cost of all equipment and materials booked to the relevant project less cost for poles/towers, lines and cables.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for the following variables in Template 2.3, Table 2.3.2 which requires expenditure data on a project close basis , for all initial regulatory years (2008/09 to 2012/13).: ▪ Voltage (KV) ▪ Route line length added – KM added ▪ Poles/Towers added ▪ Poles/Towers upgraded ▪ Poles/Towers Expenditure ▪ Overhead lines – Circuit Km added ▪ Overhead lines – Circuit Km upgraded ▪ Overhead Lines Expenditure ▪ Underground cables – Circuit Km added ▪ Underground cables – Circuit Km upgraded ▪ Underground cables Expenditure ▪ Other Plant Expenditure ▪ Installation Volume ▪ Installation (Labour) Expenditure ▪ Civil Works Expenditure

Minimum Requirements	Ergon Energy Response
	▪ Other Direct Expenditure ▪ Years Incurred ▪ All Non Related Party Contracts ▪ Land Purchase ▪ Easements ▪ Non Material Projects – Total Direct Expenditure ▪ Non Material Projects – Years Incurred ▪ Non Material Projects – Land Purchase ▪ Non Material Projects – Easements The majority of Augmentation projects incurred cost over more than one financial year and in some cases over a number of financial years. Projects with project closed dates within the reporting period (2008/09 to 2012/13) would have had cost incurred before the reporting period (pre 2008/09), which was included in expenditure disclosed in table 2.3.2.
Source of Actual Information	Actual Information for the financial variables was sourced from Ergon Energy's Ellipse operating system. Where possible, cost for projects that closed within the reporting period (2008/09 to 2012/13), but incurred costs prior to September 2006 were sourced from the Oracle system, the legacy system. The following actual Information for non-financial variables was sourced from Smallworld GIS data using search functions based on the equipment class to extract the data: ▪ Route line length added – KM added ▪ Poles/Towers added ▪ Poles/Towers upgraded ▪ Overhead lines – Circuit Km added ▪ Overhead lines – Circuit Km upgraded ▪ Underground cables – Circuit Km added ▪ Underground cables – Circuit Km upgraded The following information was taken from planning reports: ▪ Voltage (KV)
Methodology and assumption's used in relation to Actual Information	Report were run from the Ellipse operating system which listed all projects closed within regulatory years 2009 – 2013 under the Augex financial activity codes C2010, C2030, C2040 and C2050 – the RIN C2040 report and the RIN C2010, C2030, C2050 report, excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type. These reports included all Ergon Energy augmentation projects, not

Minimum Requirements	Ergon Energy Response
	only those related to Subtransmission lines. The project list was filtered to include only those projects relating to Subtransmission lines by analysing the project j-codes (asset classification codes) and extracting Subtransmission line projects. The extracted line project list reported each project and their total cumulative expenditure over the life of the project, broken down by direct costs and overheads as well as their total annual expenditure as incurred(excluding overheads). Each project with a total (whole of life) expenditure of equal or greater than $5 million (nominal, inclusive of direct and overhead costs) was reported as a separate project in the RIN template. Those projects less that $5 million were labelled as a non-material project to be consolidated into a single subtransmission line item in table 2.3.2. No projects with a total (whole of life) expenditure of equal or greater than $5 million (nominal, inclusive of direct and overhead costs) was identified through the RIN C2010, C2030, C2050 report. All projects identified through the RIN C2010, C2030, C2050 report had a total expenditure less than $5 million and was therefore included as non-material projects.The reports also provided cost per project for the following expenditure categories: Materials, Contractor cost, Labour cost, Purchases, Stores, Other direct cost. Further detailed expenditure reports were run from Ellipse on each material project providing details of each expense booked to the project. Where possible, cost for projects that closed within the reporting period (2008/09 to 2012/13), but incurred costs prior to September 2006 were sourced from the Oracle operating system. A detailed expense report was run for each of the identified material projects that had cost incurred before September 2006 from the Oracle system and cost analysed and categorised per expense type. In order to report the information in the required expense categories per table 2.3.2, Ergon Energy applied the following methodology and assumptions to the data presented in the RIN C2040 report and the data extracted from Oracle: **Poles/Towers Expenditure**, **Overhead Lines Expenditure**, **Underground cables Expenditure** was identified and calculated by reviewing individual project transaction reports (Ellipse Fin 900h reports and Oracle transaction reports) and identifying and totalling individual transactions under expense categories for “purchases’ and “contractors” that related to poles/towers, overhead lines, underground cables and civil works transactions. Civil works costs identified were categorised into civil structures (poles/towers) and other civil. Civil structure values were reported as part of the Poles/Towers Expenditure and other civil values were reported as Civil Works Expenditure. **Other Plant Expenditure** was calculated as the Total Materials and Purchases as per the RIN 2040 report, less Poles/Towers Expenditure,

Minimum Requirements	Ergon Energy Response
	Overhead Lines Expenditure, Underground cables Expenditure. **Installation Volume** was calculated as the sum of Total Labour Hours reported from Oracle, labour hours identified from RIN C2040 report and labour hours which was identified by searching each project's cost within Ellipse for Ergon Energy employees for each project. **Installation Labour Expenditure** was calculated as the Sum of Contract Labour and Internal Labour as per the RIN C2040 report and Oracle reports, less civil works labour identified through detailed analysis of labour expenditure for each project. **Civil Works Expenditure** was identified and calculated reviewing individual project transaction reports (Ellipse Fin 900h reports) and identifying civil works transactions. These costs identified were categorised into civil structures (poles/towers) and other civil. Civil structure values were reported as part of the Poles/Towers Expenditure and other civil values were reported as Civil Works Expenditure. **Other Direct Expenditure** was calculated as the Total Other Costs as per the RIN C2040 report, less the sum of Land and Easements. Total Other Cost as per RIN C2040 report includes Land and Easement cost. Other Costs includes:- ▪ Capital Interest ▪ Computer ▪ Other ▪ Transport Internal ▪ Transport External ▪ Travel & Accommodation **Years Incurred** was sourced from the RIN C2040 report. Projects carried from the legacy system (Oracle) (prior to September 2006) are reported with the commencement year of 2007. **Related Party Margins** is recorded as "zero"; Ergon Energy did not identify any Related Parties contract expenditure in relation to Augmentation projects. **All Non Related Party Contracts** is disclosed as the Total Contractors expenditure as per the RIN C2040 report. **Land Purchase and Easements** cost is included as Other Costs in the RIN C2040 report and Ellipse. Land and Easement cost was therefore calculated by running an Ellipse report for activity C2040 (augmentation) by expense element 6160 (Easement/Land), the Land & Easements C2040000006160 Report. This report provided the total land and easement cost per project. It was also confirmed that Oracle cost was brought over to Ellipse as Land and Easement to the correct expense element. To split the cost between Land purchase and Easements, we used the

Minimum Requirements	Ergon Energy Response
	BPU apportionment for Land (L5) (percentage of project cost allocated to Land) and Easements (L9) (percentage of project cost allocated to Easement) and applied this percentage to the total Land and Easement expenditure as per Ellipse report Land & Easements C2040000006160 for each project and input as Land purchase or Easements in table 2.3.2. **Non Material Projects – Total Direct Expenditure** was sourced from the RIN C2040 and RIN C2010, C2030, C2050 reports. The total cumulative expenditure (excluding overheads) over the life of the projects identified as non- material projects as per the RIN C2040 and RIN C2010, C2030, C2050 reports was listed as Total Direct Expenditure for Non Material projects in table 2.3.2. **Non Material Projects – Years Incurred** was sourced from the RIN C2040 and RIN C2010, C2030, C2050 reports. Projects carried over from the legacy system (Oracle) (prior to September 2006) are reported with the commencement year of 2007. **Non Material Projects - Land Purchase and Easements** was calculated by applying the same methodology as for Land purchase and Easements for material projects described above. The following actual Information for non-financial variables was sourced from Smallworld GIS data using search functions based on the equipment class to extract the data:: ▪ Route line length added – KM added ▪ Poles/Towers added ▪ Poles/Towers upgraded ▪ Overhead lines – Circuit Km added ▪ Overhead lines – Circuit Km upgraded ▪ Underground cables – Circuit Km added ▪ Underground cables – Circuit Km upgraded In order to provide the information required in table 2.3.2, it was necessary for Ergon Energy to run searches on data for each individual subtransmission line for the required data fields. Data was extracted by running reports on each required feeder using the feeder number as the limit for the search. Equipment classes were searched to return the number of individual assets in each class that are child assets of the parent feeder number. Where there is a zero input it means that there is zero assets in that class for the parent asset being reported on. Ergon Energy also consulted system operating diagrams and substation construction drawings to confirm data and determine the sections associated with line upgrades. **Poles/Towers upgraded, Overhead lines – Circuit Km upgraded, Underground cables – Circuit Km upgraded** – It has been assumed

Minimum Requirements	Ergon Energy Response
	that none of this type of work occurred on the feeders being reported on as all the projects were for new feeders on new line routes. It was unable to be determined from the searches conducted on Smallworld GIS of upgraded components. The following information was taken from planning reports on each individual project: ▪ Voltage (KV) **Converting nominal to real values** Ergon Energy has reported all expenditure data for Augex in Table 2.3.2 in real $2012/13. Nominal dollars has been converted to real dollars using actual CPI rates (Mar-Mar) for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS). The RIN C2040 and RIN C2010, C2030, C2050 reports provided a split of total cumulative cost (excluding overheads) in nominal values for each year in which cost was incurred. Ergon Energy applied the relevant CPI rate for each specified year in which cost was incurred to convert the nominal values to real values. The following assumptions were applied in converting nominal values to real values: **Land & Easements –** The financial year in which land and easements costs were incurred was not specified within reporting data. The assumption that land and easement costs have been incurred first was applied to convert land and easement cost to real values. **Expenditure categories -** Cost incurred by financial year cannot be split by expense category. Total project cost nominal values per year incurred have therefore been converted to real values and total real values apportioned into expenditure categories based on the nominal values allocated to each expense category. **Expenditure incurred prior to September 2006 -** Cost for projects that closed within the reporting period (2008/09 to 2012/13), but incurred costs prior to September 2006 was assumed to have fallen in 2006/07 financial year.
Use of Estimated Information	Ergon Energy has not provided estimated information in relation to Table 2.3.2.
Why is it not possible to use Actual Information, and why an estimate is required	Not applicable. Ergon Energy has not provided estimated information in relation to Table 2.3.2.
How the estimate has been produced	Not applicable. Ergon Energy has not provided estimated information in relation to Table 2.3.2.

Table 2.3.3 Augex Asset Data – HV/LV Feeders and Distribution Substations

Table 2.3.3.1 Descriptor Metrics

Table 3: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.3 - Augex project data, Table 2.3.3.1 - Descriptor Metrics (units upgraded; added in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported), excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type. Ergon Energy has not included information for gifted assets, and no augmentation in relation to connections has been included in template 2.3. Ergon Energy have considered and complied with clarifications provided by the AER on issues related to template 2.3 and relevant to Ergon Energy. With regards to instructions specific to Table 2.3.3 (on regulatory template 2.3), Ergon Energy notes: ▪ Metrics relating to augmentation works on the specified types (overhead lines, underground cables) of ***HV feeders*** owned and operated by Ergon Energy undertaken at any time during the years specified for projects with a cumulative expenditure over the life of the project greater than or equal to $0.5 million (nominal), have been reported. Descriptor metrics for Works on HV Feeders for projects with less than $0.5 million nominal expenditure over the life of the project were not required. ▪ Metrics relating to augmentation works on the specified types (overhead lines, underground cables) of ***LV feeders*** owned and operated by Ergon Energy undertaken at any time during the years specified for projects with a cumulative expenditure over the life of the project greater than or equal to $50,000 (nominal), have been

Minimum Requirements	Ergon Energy Response
	reported. Descriptor metrics on works on LV Feeders for projects with less than $50,000 nominal expenditure over the life of the project were not required. ▪ Metrics relating to augmentation works on the specified types (pole mounted, ground mounted, indoor) of ***Distribution Substations*** owned and operated by Ergon Energy undertaken at any time during the years have been reported. ▪ For projects spanning across regulatory years, *'circuit km added'*, *'circuit km upgraded'* and 'Units" data was input according to the final year in which expenditure was incurred for the project.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's definition, for the following variables in Table 2.3.3.1: ▪ Units Added & Units Upgraded - Distribution Substation Augmentations – Pole Mounted for all years; ▪ Units Added & Units Upgraded - Distribution Substation Augmentations – Ground Mounted for all years; ▪ Units Added & Units Upgraded - Distribution Substation Augmentations – Indoor for all years.
Source of Actual Information	Ergon Energy notes the source of Actual Information for the following variables: ▪ Distribution Substation Augmentations, both Units Added & Units Upgraded, was sourced from RIN C2040 and RIN C2010, C2030, C2050 reports with introduced Distribution Categories and RIN Reporting Requisitioning Data_ V6_C2040 and RIN Reporting Requisitioning Data_ V6_C2010, C2030, C2050 Report; ▪ Raw conductor and cable acquisition (by metre) was sourced from RIN Reporting Requisitioning Data_ V6_C2040 and RIN Reporting Requisitioning Data_ V6_C2010, C2030, C2050 Report.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to apply additional data qualifiers to the RIN C2040 and RIN C2010, C2030, C2050 reports to allow identification of each parcel of works by Distribution categories in accordance with the requirements of Table 2.3.3.1 In doing so, it was assumed that: ▪ All projects with an Inception to Date (ITD) cost of nil were eliminated from the reporting set after verifying a random selection of projects to confirm projects were closed with either no costs falling and/or all costs were expensed and did not proceed to asset construction or refurbishment. ▪ All Projects with Project Category (J2) Codes of either Subs-Sub-Transmission, Subs-Transmission, Lines-Sub-Transmission & Lines Transmission were outside the requirements of Table 2.3.3.2 and were eliminated from the reporting set.

Minimum Requirements	Ergon Energy Response
	▪ All projects where the primary Equipment Reference No had a ‘GS’ suffix, indicating a Generation Site, were eliminated from the reporting set, after verifying the scopes of a random selection of projects. ▪ Distribution Categories were identified from the reporting suite through the use of Project Category (J2) Codes Lines Distribution, Lines SWER, Subs Distribution and Subs SWER. ▪ Distribution Categories were validated through the use of Project Category (J3) Codes Overhead New, Upgrade or Replace; Underground New, Upgrade or Replace; Transformers New, Upgrade or Replace; Regulators New, Upgrade or Replace; SWER Isolators New, Upgrade or Replace; Steel Conductor New, Upgrade or Replace; Copper Conductor New, Upgrade or Replace; Services New, Upgrade or Replace ▪ Distribution Categories were validated through the use of Equipment Reference characteristics, such as: Equip ID Prefix SP = Substation Pole Mounted Equip ID Prefix GT = Ground Mounted Network Slot Equip ID Prefix AB = HV Isolating Device Network Slot ▪ Distribution Categories were validated through the use of Works Request Description Identifiers, such as: Reference to HV or HV Voltages (11, 22 & 33kV) Reference to SWER or SWER Voltages (12.7 & 19.1kV) Reference to LV or LV Voltages (0.240 & 0.415kV) Reference to ABC Installation (Arial Bunched Cable) Reference to UG or UG Assets (Padmount, RMU etc.) Reference to LIMS – A Dist. Substation Load Investigation management program ▪ Following the application of Distribution categories via the above process, any uncategorised projects were categorised through a review of the individual scope of works within the Works Request data. ▪ Actual information for Land Purchase and Easements was sourced from Land and Easement C204000006160.xls,C201000006160.xls, C203000006160.xls and C205000006160.xls reports and the BPU Data (Project PU Sheet) As expected, Distribution assets, which are in the majority installed on Crown land, strung beneath sub-transmission assets on existing infrastructure in existing corridors or installed with the authority of the landholder by execution of a Wayleave, returned no values for land & easements either acquired or capitalised. ▪ Substation Indoors whilst recording expenditure in all years, recorded only a single upgraded asset due to expenditure incurred in the upgrading of sites where no transformer upgrade or installation took place, such as forced air ventilation installation, HV Cable replacements and switchgear replacement

Minimum Requirements	Ergon Energy Response
	▪ Disparity of unit cost rate arises due to two factors: ▪ Units added/upgraded is based on the date of material acquisition extracted from the Store Requisition data, whereas installation costs are on an as incurred basis. ▪ Ergon Energy supply area covers 97% of the state of Queensland and experiences geographical factors associated with the supply, transport & storage of materials at significant distance from logistic bases as well as an equally significant travel component for labour resources
Use of Estimated Information	Ergon Energy has used Estimated Information for all years in relation to: ▪ HV Feeder Augmentations – Overhead lines (circuit line length KM) added and upgraded. ▪ HV Feeder Augmentations – Underground cables (circuit line length KM) added and upgraded. ▪ LV Feeder Augmentations – Overhead lines (circuit line length KM) added and upgraded ▪ LV Feeder Augmentations – Overhead lines (circuit line length KM) added and upgraded
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to HV & LV Feeder Augmentations, both Overhead Lines & Underground Cable Circuit Line Length km because no record of circuit length is maintained in alignment with individual projects.
How the estimate has been produced	HV & LV Feeder Augmentations, both Overhead Lines & Underground Cable Circuit Line Length km. In relation to Circuit Line Length km, Ergon Energy has developed an estimate based on the following approach: ▪ Ergon Energy assumed that an average circuit line length was determined based on type of cable or conductor and the required metre of conductor span or underground cable required per circuit km as set out in 'Stock Section 10 Code tables and unit rate cost analysis V6'. ▪ Ergon Energy considers that the best estimate has been provided for HV & LV Feeder Augmentations, both Overhead Lines & Underground Cable Circuit Line Length km on the basis that there was no real data captured.

Table 2.3.3.2 Cost Metrics (Expenditure)

Table 4: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.3 - Augex project data, Table 2.3.3.2 - Cost Metrics (expenditure) in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported), excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type. Ergon Energy has not included information for gifted assets, and no augmentation in relation to connections has been included in template 2.3. Ergon Energy have considered and complied with clarifications provided by the AER on issues related to template 2.3 and relevant to Ergon Energy. With regards to instructions specific to Table 2.3.3 (on regulatory template 2.3), Ergon Energy notes: ▪ Expenditure on augmentation works on the specified types (overhead lines, underground cables) of ***HV feeders*** owned and operated by Ergon Energy undertaken at any time during the years specified for projects with a cumulative expenditure over the life of the project greater than or equal to $0.5 million (nominal), have been reported. Works on HV Feeders for projects with less than $0.5 million nominal expenditure over the life of the project have been consolidated into the Non-material projects row of the table. ▪ Expenditure on augmentation works on the specified types (overhead lines, underground cables) of ***LV feeders*** owned and operated by Ergon Energy undertaken at any time during the years specified for projects with a cumulative expenditure over the life of the project greater than or equal to $50,000 (nominal), have been reported. Works on LV Feeders for projects with less than $50,000 nominal expenditure over the life of the project have been consolidated into the Non-Material Projects row of the table. ▪ Expenditure on augmentation works on the specified types (pole mounted, ground mounted, indoor) of ***Distribution Substations*** owned and operated by Ergon Energy undertaken at any time during the years have been reported. ▪ Projects were included for augmentation and the addition of equipment on HV Feeders, LV Feeders and Distribution substations i.e. monitoring and communication equipment under table 2.3.3.2, even though there were no additional HV Feeders, LV Feeders and

Minimum Requirements	Ergon Energy Response
	distributions substations units added (circuit length kms).Expenditure has been recorded on an 'as incurred' basis in nominal dollars' ▪ Expenditure related to land purchases and easements is not included in the 'Total Direct Expenditure' column. Land purchases and easements expenditure related to augmentation works on all ***HV feeders, LV Feeders*** or ***Distribution Substations*** owned and operated by Ergon Energy must be input in table 2.3.6.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 2.3.3.2 for the period 2008/09 to 2012/13.
Source of Actual Information	Actual Information for Total Direct Expenditure was sourced from RIN C2040 and RIN C2010, C2030, C2050 reports, an extract from the Ellipse financial database of all Capital Works expenditure by cost category and financial year which was funded through Activity C2010, C2030, C2040 and C2050 (Augmentation).
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to apply additional data qualifiers to the RIN C2040 and RIN C2010, C2030, C2050 reports to allow identification of each parcel of works by Distribution categories in accordance with the requirements of Table 2.3.3.2 In doing so, it was assumed that: ▪ All projects with an Inception to Date (ITD) cost of nil were eliminated from the reporting set after verifying a random selection of projects to confirm projects were closed with either no costs falling and/or all costs were expensed and did not proceed to asset construction or refurbishment. ▪ All Projects with Project Category (J2) Codes of either Subs-Sub-Transmission, Subs-Transmission, Lines-Sub-Transmission & Lines Transmission were outside the requirements of Table 2.3.3.2 and were eliminated from the reporting set. ▪ All projects where the primary Equipment Reference No had a 'GS' suffix, indicating a Generation Site, were eliminated from the reporting set, after verifying the scopes of a random selection of projects. ▪ Distribution Categories were identified from the reporting suite through the use of Project Category (J2) Codes Lines Distribution, Lines SWER, Subs Distribution and Subs SWER. ▪ Distribution Categories were further identified through the use of Project Category (J3) Codes Overhead New, Upgrade or Replace; Underground New, Upgrade or Replace; Transformers New, Upgrade or Replace; Regulators New, Upgrade or Replace; SWER Isolators New, Upgrade or Replace; Steel Conductor New, Upgrade or Replace; Copper Conductor New, Upgrade or Replace; Services

Minimum Requirements	Ergon Energy Response
	New, Upgrade or Replace ▪ Distribution Categories were further identified through the use of Equipment Reference characteristics, such as: Equip ID Prefix SP = Substation Pole Mounted Equip ID Prefix GT = Ground Mounted Network Slot Equip ID Prefix AB = HV Isolating Device Network Slot ▪ Distribution Categories were further identified through the use of Works Request Description Identifiers, such as: Reference to HV or HV Voltages (11, 22 & 33kV) Reference to SWER or SWER Voltages (12.7 & 19.1kV) Reference to LV or LV Voltages (0.240 & 0.415kV) Reference to ABC Installation (Arial Bunched Cable) Reference to UG or UG Assets (Padmount, RMU etc.) Reference to LIMS – A Dist. Substation Load Investigation management program ▪ Following the application of Distribution categories via the above process, any uncategorised projects were determined through a review of the individual scope of works within the Works Request data. ▪ Actual information for Land Purchase and Easements was sourced from Land and Easement C204000006160.xls, C201000006160.xls, C203000006160.xls and C205000006160.xls reports and the BPU Data (Project PU Sheet) As expected, Distribution assets, which are in the majority installed on Crown land, strung beneath sub-transmission assets on existing infrastructure in existing corridors or installed with the authority of the landholder by execution of a Wayleave, returned no values for land & easements either acquired or capitalised. ▪ Substation Indoors whilst recording expenditure in all years, recorded only a single upgraded asset due to expenditure incurred in the upgrading of sites where no transformer upgrade or installation took place, such as forced air ventilation installation, HV Cable replacements and switchgear replacement ▪ Disparity of unit cost rate arises due to two factors: ▪ Units added/upgraded are based on the date of material acquisition extracted from the Store Requisition data, whereas installation costs are on an as incurred basis. ▪ Ergon Energy supply area covers 97% of the state of Queensland and experiences geographical factors associated with the supply, transport & storage of materials at significant distance from logistic bases as well as an equally significant travel component for labour resources.
Use of Estimated Information	Ergon Energy has not provided Estimated Information in Table 2.3.3.2.
Why is it not possible to	Not applicable. Ergon Energy has not provided Estimated Information in

Minimum Requirements	Ergon Energy Response
use Actual Information, and why an estimate is required	Table 2.3.3.2.
How the estimate has been produced	Not applicable. Ergon Energy has not provided Estimated Information in Table 2.3.3.2.

Table 2.3.4 Augex Asset Data – Total Expenditure

Table 5: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.3, Table 2.3.4 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported). Ergon Energy has not included information for gifted assets, and no augmentation expenditure in relation to connections has been included in template 2.3. Total augmentation expenditure has been input for each asset group split by the groupings specified by the table. Expenditure has been recorded on an ‘as incurred’ basis in nominal dollars’. Expenditure inputted under the ‘land and easements’ rows are mutually exclusive from expenditure that appears in the rows for the corresponding asset group. In regards to requirements in paragraph 7.7(b) Ergon Energy provides the following explanation in relation to reconciling the expenditure in Table 2.3.4 to the sum of the asset group augmentation expenditures in Table 2.3.1 (Subtransmission substations, switching stations, zone substations) and Table 2.3.2 (Subtransmission Lines) and Table 2.3.3 (HV/LV Feeders and Distribution Substations): ▪ The data sources for information disclosed in tables 2.3.1, 2.3.2, 2.3.3.2 and 2.3.4 are identical, being the C2040 and RIN C2010, C2030, C2050 reports from the Ellipse operating system. The base data used for all tables will therefore reconcile, However, due to the inconsistencies in the basis of preparation and disclosure requirements, the following will apply to tables 2.3.1 and 2.3.2: ▪ Projects listed in Table 2.3.1 and Table 2.3.2 are disclosed on a project closed basis and projects included in Table 2.3.4 are disclosed on a cost incurred basis.

Minimum Requirements	Ergon Energy Response
	▪ Ergon Energy has reported all expenditure data for Augex in Table 2.3.1 and Table 2.3.2 in real $2012/13 as required by the Principles and Requirements in the Category Analysis RIN and expenditure data for Table 2.3.4 in nominal dollars. ▪ The majority of Augmentation projects listed in Table 2.3.1 and Table 2.3.2 incurred cost over more than one financial year and in some cases over a number of financial years. ▪ Projects with close dates within the reporting period (2008/09 to 2012/13) and disclosed in Table 2.3.1 and Table 2.3.2 would have had cost incurred before the reporting period (pre-2008/09). This cost incurred before 2008/09 is not reported in Table 2.3.4 expenditures, as the cost did not incur within the reporting period (2008/09 to 2012/13). ▪ Opposite to this, projects and the associated cost may have been reported in Table 2.3.4 in the year it incurred, but not reported in Tables 2.3.1 and 2.3.2 given the projects were not finalised and closed within the reporting years. ▪ Expenditure reported in Table 2.3.3.2 reconciles to expenditure disclosed in Table 2.3.4 for HV Feeders, LV Feeders, Distribution Substations, HV Feeders – Land purchases and Easements, LV Feeders – Land purchases and Easements and Distribution Substations – Land purchases and Easements, as the basis of preparation and data sources are identical.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's definition for all variables in Table 2.3.4 for the period 2008/09 to 2012/13.
Source of Actual Information	Actual Information for Total Expenditure was sourced from RIN C2040 and RIN C2010, C2030, C2050 reports, an extract from the Ellipse financial database of all Capital Works expenditure by cost category & financial year which was funded through Activities C2010, C2030, C2040 and C2050 (Augmentation).
Methodology and assumption's used in relation to Actual Information	Data disclosed in Table 2.3.4 was sourced from the C2040 and RIN C2010, C2030, C2050 reports and reported as appearing on the reports without making any assumptions or adjustments to the data. HV Feeders – Land purchases and Easements, LV Feeders – Land purchases and Easements and Distribution Substations – Land purchases and Easements are reported at zero value. Distribution assets are placed within the road reserved and as such do not require land or easement acquisitions. Where distribution assets cross private property Ergon Energy takes Wayleave Agreements form the property owners, which are binding on subsequent owners, giving Ergon Energy the right to access and maintain the distribution assets without the need to acquire land. Projects under activity codes C2010, C2030, C2040 and C2050 that relates to augmentation, excluding costs relating to non-network assets

Minimum Requirements	Ergon Energy Response
	identified as part of the annual performance RIN preparation, but could not be classified under the specified asset categories of subtransmission substations, switching stations, zone substations, subtransmission Lines, HV/LV feeders and distribution substations was disclosed as “other assets” in table 2.3.4. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type. The P25 Digital Radio project was re-classified from augmentation expenditure and reported as replacement capital expenditure in template 2.2. This was not previously reported in past Annual Performance RIN’s. The total dollar impact is a decrease of $12M to augmentation expenditure. The P25 Digital Radio project expenditure has been allocated to REPEX through independent consultation with SME’s that worked closely on the projects. At the time of the project these SME’s were the Project Manager, Network Architect and Telecommunication Network & Design Manager combined they have significant experience in the industry. They determined the allocation of the project by having an in-depth knowledge of the existing Ergon Network prior to the commencement of the project.
Use of Estimated Information	The Ubinet project was included as an estimate under “other assets” in table 2.3.4.
Why is it not possible to use Actual Information, and why an estimate is required	Ubinet relates to a large number of assets and aspects across the Ergon Energy’s distribution network. 75% of the Ubinet project expenditure was included as augmentation “other assets” and 25% of the Ubinet project as replacements and expenditure based on SME knowledge. The portion of 25% of the overall Ubinet project expenditure has been estimated to be allocated to REPEX through independent consultation with 3 SME’s that worked closely on the project. At the time of the project these SME’s were the Project Manager, Network Architect and Telecommunication Network & Design Manager combined they have around 80yrs experience in the industry. They determined the allocation of 25% by having an in-depth knowledge of the existing Ergon Network prior to the commencement of the project. As the project moved forward it became evident that aged asset replacement would be a more viable option than the creation of new sites and that is the direction a portion of the project then took. At the time of collecting the data for RIN, the SME’s consulted in relation to the Ubinet Project all came back with the figure of 25%.
How the estimate has been produced	75% of the Ubinet project expenditure was included as augmentation “other assets” and 25% of the Ubinet project as replacements and expenditure based on SME knowledge.

Appendix A: Template 2.3 Table 2.3.1 (*Other – specify)*

Substation ID	Project Number	Substation Type	Substation description	Project Type	Reason for choosing “Other”	Project Trigger	Reason for choosing “Other”	Additional comments
20006664	CPMNN00734	Zone Sub-station		Other-specify	Installation of another 66kV feeder bay	Demand growth		
82647119	CPMNN00140	Zone Sub-station		Other-specify	This project is for land acquisition for a new substation (Project ID CPMNN01306) disclosed separately in Table 2.3.1.	Demand growth		
40222461	CPMNS00567	Other-specify	Skid mounted substation	Other-specify	Substations have been used for deployment to either establish a new site quickly or provide additional capacity to an existing site quickly.	Other-specify	Could be any of the types listed depending on the circumstances	Project was for the construction of 5 Skid Mounted Substations. The substations could be deployed to new sites or existing sites, based on the identified need. The voltage ratios provided are the ratios which were ordered under the construction contract. The MVA ratings is the sum of all five transformer ordered under this project. To date only 4 have been installed. The transformer and switch unit numbers are the total used on all five units.

Category Analysis RIN Basis of Preparation

Template 2.5 Connections

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.5 Connections of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.5 Connections (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.5 Connections, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.5 Connections (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.5 Connections

Table 2.5.1 - Descriptor Metrics

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.5, Table 2.5.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. As advised by the AER, Ergon Energy has not had regard to paragraph 9.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN. In completing the template, Ergon Energy has not distinguished expenditure between Standard or Alternative Control Services. Similarly, Ergon Energy has not distinguished between capex or opex. Furthermore, costs have been measured as the direct cost, excluding overheads. Ergon Energy has reported expenditure data as a gross amount, that is to say, customer contributions have not been subtracted from expenditure. Data has not been reported in relation to gifted assets, or connection services which have been classified as contestable by the AER. Rather, information relates only to non-contestable, regulated connection services, including works performed by third parties on behalf of Ergon Energy. Ergon Energy does not have negotiated connection services; therefore no metrics are included in this regard. For augmentation metrics, the 'km added' reported refers to the net addition of circuit line length resulting from augmentation work of complex connections. The definition for complex connections has been referred to in this regard, and for other metrics as relevant. Only augmentation for connections relating to customer connection requests (as per the defined term for connection expenditure) has been reported in Template 2.5. That is, no double counting in reporting of augmentation expenditure has occurred between Template 2.5 (Connections) and Template 2.3 (Augex). *MVA added* for distribution substations installed for connection services was calculated as the sum of the nameplate rating of all distribution substations installed for the relevant year. Unless explicitly stated as not being provided fields with no value

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response</th></tr>
<tr><td></td><td>entered should be considered as having no expenditure or units in the relevant year</td></tr>
<tr><td>Use of Actual Information</td><td>Ergon Energy has provided Actual Information, in accordance with the AER’s definition, for the following variables in Table 2.5.1 for the initial regulatory years 2008/09 to 2012/13, for both financial and non-financial information:
▪ Mean Days to Connect Customers
▪ GSL Breaches
▪ Customer Complaints
▪ GSL Payments
The categorisation requested in the template for all other variables is not available in the underlying source systems and therefore Ergon Energy has provided Estimated Information (refer below).</td></tr>
<tr><td>Source of Actual Information</td><td>For non-financial information (volumes), actual data was available from Ellipse for the Mean Days to Connect Customers and GSL Payments
GSL information and complaints has been sourced from GSL Report which is an enterprise system</td></tr>
<tr><td>Methodology and assumption’s used in relation to Actual Information</td><td>In order to obtain the information, Ergon Energy applied the following methodology and assumptions:
GSL Payments
<u>GSL payments have been extracted directly from Ellipse</u>
Non-Financial Metric - Mean Days to Connect Residential Customers
Mean Days to Connect Residential Customers data has been sourced from existing Ellipse reporting in relation to total customer connection time. This file was cross referenced with the work requests related to residential customers to identify the applicable work requests within the subcategory
Non-Financial Metrics - GSL Breaches, Customer Complaints
GSL information and complaints has been sourced directly from GSL Report which is an enterprise system.</td></tr>
<tr><td>Use of Estimated Information</td><td>Ergon Energy has provided Estimated Information in relation the following Financial information and non-financial metrics in Table 2.5.1 for the initial regulatory years 2008/09 to 2012/13, for both financial and non-financial information:
▪ Connections
▪ Substations Installed
▪ Substations Installed MVA
▪ Circuit Kilometres
▪ Cost per Lot</td></tr>
</table>

Minimum Requirements	Ergon Energy Response
	Estimated information for connection LV circuit kilometres added has been derived from an average rate per connection.
Why is it not possible to use Actual Information, and why an estimate is required	The categorisation requested in the template does not exist within the Ellipse system. Whilst the source data is based on actual transactions, RIN categorisation has been determined based on applying assumptions and methodologies (discussed below). Estimated information for connection LV circuit kilometres added has been derived from an average rate per connection. Variability in booking practices (LV connections) resulted in anomalies in the data. Given the significant quantity of underlying work requests and time available Ergon Energy has not been able to verify this information spatially.
Source of Estimated Information	Underlying actual information for financial (expenditure) and non-financial information for Table 2.5.1 was sourced from Ellipse. However, to disaggregate into the required metrics, an overlay of the below assumptions and methodology was required by Ergon Energy.
How the estimate has been produced	**Financial information and non-financial metrics** ▪ Connections ▪ Distribution Substations Installed ▪ Installed MVA ▪ Circuit Kilometres ▪ Augmentation HV/LV Financial and non-financial information has been presented on an as incurred basis, the non-financial information was pro-rata on a consistent basis with the financial expenditure. A filter was incorporated into the underlying data in order to exclude contestable, gifted, metering and street lighting work requests based on system information found on the work requests The Ellipse system provides the appropriate subcategories to differentiate between Residential, Commercial and Subdivision. The Embedded Generation subcategory does not exist in Ellipse and therefore the work requests attributable to this category were required to be manually identified by cross referencing the embedded generation contracts with work requests. The Metric information requested for connections differentiating between overhead and underground is not available via a system report. To obtain this information requisitioning data was used to identify by the materials used on each work request whether a connection was an overhead or underground connection, Distribution Substations installed were also sourced from the requisition data on the work request and the nameplate rating were used to Determine MVA added. The Metric information requested for differentiating between HV and LV

Minimum Requirements	Ergon Energy Response
	is not available via a system report. To obtain this information requisitioning data was used to identify by materials whether a work request was likely to be HV and LV. Circuit Kilometres added was taken from the requisitioning data and the associated total spends on the work requests was categorised accordingly. The specifics of the process were as follows: Financial information and non-financial metrics (connections, Installed MVA, Circuit Kilometres added) were sourced from Ellipse by the running an adhoc MERS (Mincom Ellipse Reporting System) report “RIN Reporting Requisitioning Data V6” built internally for the purposes of producing requisitioning data. The report extracts relevant requisitioning data associated with connections and includes fields that would allow cross referencing and filtering to produce the category breakdown required for completion of Template 2.5. Of note: ▪ A report was run against the Master Transactional File (all ellipse source data) and limited to be greater than 1 July 2006 (to ensure it covers all possible transactions within the review period) ▪ A report was run by the Activity codes (part of the Ellipse general ledger combination to classify transactions) relevant to all potential customer connections, specifically - C2220, C2120, C2110, C2080, C2070, C2085 and C2060. (C2090 – Generation – not included); ▪ All XX coded Stock Section 10 codes were excluded as these do not relate to customer connections ▪ The report was then hard coded to allow other data to be imported and filtered to achieve the required categorisation - The following specific steps were applied o *Ratio* – applies a ratio to the quantities for each SS10 item (e.g. conductor is divided by the appropriate amount to create circuit KM’s). Some are coded at 0 to prevent double counting (e.g., Pillar Bases are ‘0’ but pillar bases are ‘1’). o *RIN Code* – rolls stock description code (Stock Section 10) codes up to a view the more closely aligns with the RIN. o *EE Code* – rolls the Stock Section 10 codes up to a view that more closely aligns with a typical Ergon Energy view. o A view produced that summarises the Stock Section 10 to Cables that is OH or UG. This is ultimately used to classify the work request as either OH or UG. If the work requests consists of both components the element with the higher Qty determines the classification o A view produced that summarises the Stock Section 10 to cables as LV, HV or Services. This is ultimately used to classify the work request as either LV, HV or Service. If the work requests

Minimum Requirements	Ergon Energy Response
	consists of multiple components the element with the higher Qty determines the classification A separate MERs report was then produced to match the unique identifying "work order" in the requisitioning data to the global unique identifier "work request" and associated parent project. A report was run of the financial results in business objects (Report writing tool) and the Requisition data is cross referenced to this report. It should be noted that unsuccessful work was removed (work that did not proceed and where the project costs have been operational expensed to a value of Nil). The final output allows all the above data to be filtered to show the classifications required for the financial information and non-financial metrics (connections, Installed MVA, Circuit Kilometres added). LV Circuit Kilometres added has been determined by utilising an average rate per connection. The work requests for the relevant segment were reviewed and normalised based on circuit kilometres requisitioned (to exclude obvious anomalies). The average rate for each segment was then applied to the actual number of connections for each period. Ergon Energy considers this to be the appropriate basis to provide the best estimate possible as it used actual system generated source data from the underlying work requests to be able to provide the information on the descriptor metrics requested

Table 2.5.2 - Cost Metrics by Connection Classification (Volumes and Expenditure)

Table 2: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.5, Table 2.5.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. In completing the template, Ergon Energy has not distinguished expenditure between Standard Control Services or Alternative Control Services. Similarly, Ergon Energy has not distinguished between capex or opex. Furthermore, costs have been measured as the direct cost, excluding overheads. Ergon Energy has reported expenditure data as a gross amount, that is to say, customer contributions have not been subtracted from

Minimum Requirements	Ergon Energy Response
	expenditure. Data has not been reported in relation to gifted assets, or connection services which have been classified as contestable by the AER. Data relates only to non-contestable, regulated connection services, including works performed by third parties on behalf of Ergon Energy. Ergon Energy does not have negotiated services; therefore no metrics are included in this regard. The definition for complex connections has been referred to in relation to cost and descriptor metrics as relevant. Only augmentation for connections relating to customer connection requests (as per the defined term for connection expenditure) has been reported in Template 2.5. That is, no double counting in reporting of augmentation expenditure has occurred between Template 2.5 (Connections) and Template 2.3 (Augex).
Use of Actual Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, for all variables in Table 2.5.2 for the initial regulatory years 2008/09 to 2012/13, for both financial and non-financial. Although underlying actual information was available in some instances, the categorisation requested in the template were not available in the source systems. Rather, estimation was required by Ergon Energy using an overlay of assumptions and methodologies as described below.
Source of Actual Information	Not applicable: Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Methodology and assumption's used in relation to Actual Information	Not applicable: Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition, for all variables in Table 2.5.2 for the initial regulatory years 2008/09 to 2012/13, for both financial and non-financial information. Although underlying actual information was available for the following variables, the categorisation requested in the template is not available in the underlying source systems and estimation was required by Ergon Energy using an overlay of assumptions and methodologies: ▪ Residential Complex connection LV and HV ($000's) & (000's) ▪ Commercial/industrial complex connection HV (customer connected at HV) ($000's) & (000's) ▪ Subdivision complex connection LV ($000's) & (000's) ▪ Embedded generation simple connection LV ($000's) & (000's) ▪ Embedded generation complex connection HV (small capacity and large capacity) & (000's) ($000's).

Minimum Requirements	Ergon Energy Response
	▪ Complex Connection Sub-Transmission ($000's) & (000's) Ergon Energy has provided Estimated Information for the following variables, as information was not able to be directly sourced from systems: ▪ Residential - simple connection LV ($000's) & (000's) ▪ Commercial/industrial - simple connection LV ($000's) & (000's) ▪ Commercial/industrial - complex connection HV (customer connected at LV, minor HV works) ($000's) & (000's) ▪ Commercial/industrial -complex connection HV (customer connected at LV, upstream asset works) ($000's) & (000's) ▪ Subdivision - complex connection HV (no upstream asset works) ($000's) & (000's) ▪ Subdivision - complex connection HV (with upstream asset works) ($000's) & (000's)
Why is it not possible to use Actual Information, and why an estimate is required	For the variables noted above, whilst the source data is based on actual transactions the categorisation requested in the template does not exist within Ergon Energy's Ellipse system. Furthermore, an estimate is required in relation to splitting simple LV connections between the Residential and Commercial segments because Ergon Energy does not have a data field to make this segregation. Similarly, an estimate is required in relation to differentiating between upstream and non-upstream works as the actual dollars and physicals are all captured on a single project or work request.
How the estimate has been produced	The Ellipse system provides the appropriate subcategories to differentiate between Residential, Commercial and Subdivision. The Embedded Generation subcategory does not exist in Ellipse and therefore the work requests attributable to this category were required to be manually identified. The Metric information requested for differentiating between Simple and Complex, HV and LV is not available via a system report. To obtain this information requisitioning data was used to identify by materials whether a work request for each specific connection was likely to be simple/ complex, HV and LV. Ergon Energy was not able to use the information on the work request to appropriately classify simple connections between the residential and Commercial/Industrial subcategories, please refer section below for additional steps taken The specifics of the process were as follows; Financial information and non-financial metrics were sourced from Ellipse by running an adhoc MERS (Mincom Ellipse Reporting System) report "RIN Reporting Requisitioning Data V6" been built internally for

Minimum Requirements	Ergon Energy Response
	the purposes of producing requisitioning data. The purposes of the report was to extract relevant requisitioning data associated with connections and include fields that would allow cross referencing and filtering to produce the category breakdown required in the information notice. Of note: ▪ The report was run against the Master Transactional File (all ellipse source data) and limited to be greater than 1 July 2006 (to ensure it covers all possible transactions within the review period) ▪ The report is run by the Activity codes (part of the Ellipse general ledger combination to classify transactions) relevant to all potential customer connections, specifically - C2220, C2120, C2110, C2080, C2070, C2085 and C2060. (C2090 – Generation – not included); ▪ All XX coded Stock Section 10 codes were excluded as these do not relate to customer connections ▪ The report was then hard coded to allow other data to be imported and filtered to achieve the required categorisation- The following specific steps were applied o ***Ratio*** – applies a ratio to the quantities for each SS10 item (e.g. conductor is divided by the appropriate amount to create circuit KM's). Some are coded at 0 to prevent double counting (e.g., Pillar Bases are '0' but pillar bases are '1'). o ***RIN Code*** – rolls stock description code (Stock Section 10) codes up to a view the more closely aligns with the RIN. o ***EE Code*** – rolls the Stock Section 10 codes up to a view that more closely aligns with a typical Ergon view. o A view produced that summarises the Stock Section 10 to Cables that is OH or UG. o A view produced that summarises the Stock Section 10 to cables as LV, HV or Services. A separate MERs report was then produced to match the unique identifying "work order" in the requisitioning data to the global unique identifier "work request" and associated parent project. A report was run in MERs to obtain a count of work orders associated with projects with classification J3 code of "New" or "upgrade to services" to ensure only connections were included. A report was run of the financial results in business objects (Report writing tool) and the Requisition data is cross referenced to this report. It should be noted that unsuccessful work was removed (work that did not proceed and where the project costs have been operational expensed to a value of Nil). A filter was incorporated into the data set in order to exclude contestable, gifted, metering and street lighting work requests based on

Minimum Requirements	Ergon Energy Response
	system information The final output allows all the above data to be filtered to show the classifications required for the financial information and non-financial metrics. The non-financial information, quantitates have been taken from the relevant work request and pro-rated on an as incurred basis consistent with financial information Ergon Energy considers this to be the appropriate basis to provide the best estimate possible as it used actual system generated source data from the underlying work requests to be able to provide the information on the categorisation requested <u>Residential and Commercial – Simple LV Connection</u> In relation to the above variable Ergon Energy has developed an estimate based on the following approach: ▪ System data was available for Simple connection LV which incorporates both Residential and Commercial/Industrial subcategories ▪ A high level split of the aggregate data based on customer numbers in each segment for each year has been used to apportion Simple connection LV between Residential and Commercial/Industrial subcategories In developing this estimate, Ergon Energy has made the following assumptions: ▪ Customer numbers in each segment provide a good proxy for the apportion of Simple connection LV Ergon Energy considers this approach represents the best estimate on the basis that: ▪ Actual data is not available; and ▪ Customer numbers in each of the subcategories are expected to provide a good proxy for the distribution of Simple LV Connections <u>Upstream and Non-Upstream Components</u> ▪ In relation to the above variable Ergon Energy is unable to differentiate between upstream and non-upstream works at the underlying work request level. Ergon Energy has previously provided as part of its regulatory reset submission a basis for splitting the components for each category based on sampling of completed projects to determine a reasonable basis for apportionment. The % split of upstream components has been applied to the actual source data to provide an estimated breakup of the upstream components Ergon Energy consider that this represents the best estimation on the basis that Actual data is not available and the method is consistent with that previous used by Ergon Energy.

Category Analysis RIN Basis of Preparation

Template 2.6 Non Network

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.6 Non Network of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.6 Non Network (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.6 Non Network, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.6 Non Network (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.6 Non Network

Table 2.6.1 Non-Network Expenditure

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.6, Table 2.6.1 Non Network Expenditure in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. In completing Table 2.6.1 – Non-Network Expenditure, Ergon Energy notes that: ▪ Ergon Energy has reported Non Network expenditure in relation to standard control services only. ▪ Ergon Energy has inserted additional *“asset categories”* under the *“service subcategory”* to represent office furniture and equipment, plant and equipment, crane borer plant HCV and other fleet assets. These *“asset categories”* were added as they have incurred $1 million or more (nominal) in capital expenditure over the last five regulatory years; ▪ Ergon Energy has included the replacement, installation, operation and maintenance of non-network buildings, fittings and fixtures in non-network buildings and property expenditure. This includes expenditure related to real chattels; ▪ Ergon Energy has included expenditure related personal chattels (e.g. furniture) under Non-network Office Furniture & Equipment. ▪ Ergon Energy has included in non-network IT and communication expenditure, costs associated: o SCADA and Network Control that exist at the Corporate office side of gateway devices; o IT & Communications related to management, dispatching and coordination, etc. of network work crews; o Common costs shared between the SCADA and Network Control Expenditure and IT & Communications Expenditure categories with no dominant driver related to either of these expenditure categories; and o Network metering recording and storage at non network sites. ▪ Ergon Energy has reported all expenditure directly attributable to Motor Vehicles including: purchase, replacement, operation and maintenance of motor vehicles assets registered for use on public roads, excluding mobile plant and equipment. Depreciation has

Minimum Requirements	Ergon Energy Response
	been excluded as it does not meet the definition of Operating Expenditure. ▪ Ergon Energy has included all expenditure directly attributable to the replacement, installation, maintenance and operation of Non-network assets in non-network other expenditure. This includes: o non road registered motor vehicles; non road motor vehicles; o mobile plant and equipment; tools; trailers (road registered or not); o elevating work platforms not permanently mounted on motor vehicles; and o mobile generators. ▪ The numbers reported for Non-Network expenditure have been balanced back to Annual Performance RINs where there is commonality in reporting categories.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for Table 2.6.1 for: ▪ Buildings and Property for the period 2008/09 – 2012/13; ▪ IT and Communications for the period 2008/09 – 2012/13; ▪ Motor vehicles 2008/09 – 2012/13; ▪ Office furniture and equipment 2008/09 – 2012/13; ▪ Plant and Equipment 2008/09 – 2012/13; ▪ Crane Borer Plant HCV 2008/09 – 2012/13; ▪ Other fleet assets 2008/09 – 2012/13; and ▪ Other expenditure 2008/09 – 2012/13.
Source of Actual Information	Actual Information for the variables was sourced from Ergon Energy's ERP – Ellipse.
Methodology and assumption's used in relation to Actual Information	Data was sourced from Ergon Energy's ERP – Ellipse. [Expenditure Report. EEA90R OMD]. The report requests several inputs: Responsibility Centre/s (RC), Activity Code/s, and Period of inquiry. The RC and Activity is based on Ergon Energy's Chart of Accounts from which actual expenditure is reported against. The output is itemised lines of expenditure data listed against an account code and where administered as such, the work order number and respective details are given (equipment ID, work category, workgroup etc.). In order to obtain the information, it was necessary for Ergon Energy to run reports against the financial data for the period of time 200901 to 201312 (i.e. 1 July 2009 to 30 June 2013). The Capex and Opex figures have been determined as follows.

Minimum Requirements	Ergon Energy Response
	BUILDING AND PROPERTY CAPEX: Property capex was derived by summing the expenditure previously reported for Non-System Buildings, Land and Land Improvements in the relevant Annual Performance RIN or QCA Regulatory Reporting Statements. The expenditure for the relevant capex codes was extracted from the Ellipse General Ledger and the proportion of the total that relates to overheads was calculated. The fully absorbed costs as reported in the previous Annual Performance RINS was then reduced by this proportion to give the direct capital expenditure. . OPEX: It was assumed that all Buildings and Property Opex is recorded against Responsibility Centres 1250, 1255, 1260, 1270, 1280, 1290, 1300 and Activities 63900, 63910, 63920, 63930 and 62500 as detailed in the Chart of Accounts through running the OMD Expenditure Report. ▪ RC1250 is named Service Capability and is a support function for the RC's 1255-1290 (Property Services – Facilities) and RC1300 (Property Construction). Activities 63900-63930 are described as Property Services (Maintenance & Non-maintenance), while 62500 is Business Support Services and relates to the support related functions for the delivery of direct services. ▪ Data is filtered to exclude Expense Elements 5000 – Capitalisation, and EE 8100 – Business Overheads. ▪ The data was also filtered based on the equipment reference. Historically, some expenditure under these RC and Activities has been fully attributable to non-regulated assets and non-standard control services. Where equipment references (or their child assets) are identified as: BACH (EEQ Barcaldine Residence), BAWI (EEQ Barcaldine Residence), CAHA (Non-regulated Cairns site), TIPO (Thursday Island Office) & TIRI (Thursday Island Depot), these costs were excluded. ▪ Line items are reviewed and where the Work Order Description can be confidently identified as a chattel, the item was highlighted in green and reported within the 'Other' Expenditure category, rather than the 'Buildings and Property' category. These items broadly fall within the 'Furniture' and 'Capital Purchases' work categories (Job Code 5), although not all furniture and purchases fall under the AER's definition of a chattel. There are some (minimal) expenditure line items which are listed with the above RC and activities and are reported against a network or fleet related asset. These items were identified by the Equip Reference field. These assets are not non-network property assets, but Opex has been spent against them in the context of Property based expenditure (or on-charged). These items remain in the data and are reported as part of this expenditure. In the context of the overall expenditure, they account

Minimum Requirements	Ergon Energy Response
	for less than 0.5%. There remains expenditure reported that is considered not directly attributable to an asset (i.e. building). This includes costs which support the people who deliver the services to the assets and general administration costs. These costs are predominately listed under activity 62500. The Buildings and Property Opex data reported in table 2.6.1 represents a cumulative sum of the twelve months for each of the respective initial regulatory (financial) years. ***IT AND COMMUNICATIONS*** Data was sourced from Ergon Energy's ERP – Ellipse. Client devices was extracted from expense element 4500 direct purchases and were all capital in nature as these were devices that were connected to the server as per the AER definition. AER Definition Client Devices Expenditure is expenditure related to a hardware device that accesses services made available by a server. Client Devices Expenditure includes hardware involved in providing desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones, tablets and laptops. Recurrent expenditure is unable to be extracted directly from a report. Rather it is a balancing item which is calculated by subtracting the total non-current and client device from the total reported IT & Communications costs reported in previously submitted RINs to the AER.. Non-current expenditure was extracted from 4500 direct purchases 2009 for FACOM software Capital in nature. There were no client devices that were opex in nature. 2013 non-current expenditure was extracted from RC 0385 for SPARQ Blue printing and Ellipse 8 project which is capex in nature. ***MOTOR VEHICLES*** The Opex cost of motor vehicles was based on an extraction of transport transactions from the relevant transport costing elements. The non-related opex transport costs were then removed. The remaining relevant transactions contain an equipment number. The equipment number is attached to equipment group identification number. A matrix was created to align the equipment group identification numbers with the RIN categories for Motor Vehicles. In instances were an equipment number was not assigned to a transaction, the unassigned costs were apportioned across the RIN categories based on the already assigned proportions. Hire vehicles (Hire Car, Hire Light Commercial Vehicle, Hire Heavy Commercial Vehicle and Other) have been identified separately due to their different total cost structure compared to Ergon Energy owned motor vehicles. Ergon Energy regards hire vehicle OPEX as a valid

Minimum Requirements	Ergon Energy Response
	expenditure to benchmark its business performance, but not to directly benchmark against owned motor vehicle OPEX. Hire vehicles were identified in the abovementioned process by a unique set of equipment group identification numbers. Ergon Energy has made this categorisation to highlight its change in strategic direction of focusing on its own fleet and reduce its use of hire vehicles. The data file detailing registration costs for 2008/09 could not be located. The actual registration and Insurance costs are not directly costed to the fleet item in the ellipse system. Registration and Insurance costs are costed to each fleet item as part of a Fleet Management Fee. The Fleet management fee also includes depreciation. To remove depreciation from the opex exercise, the fleet management fee was removed in total and the registration costs were added back. Registration costs for 2008/09 have been based on the 21/07/2009 registration figures. This assumption was used due to the relatively stable nature of the fleet at that time. The Capex cost of motor vehicles was based on an extraction of transactions from the relevant fleet Work In Progress Activity accounts (C-Accounts) in the general ledger, with reference to the transport costing elements related to fleet equipment numbers in the general ledger. All transactions from all fleet related Work In Progress Activity accounts were extracted. All the transactions linked to fleet equipment numbers were identified from this extract from the general ledger and isolated as the total CAPEX cost related to Fleet vehicles for the specific financial years in question. The equipment number is attached to equipment group identification number. The transport transactions were then filtered to those relating to the specific EGI numbers associated to the above mentioned fleet assets. A matrix was created to align the equipment group identification numbers with the RIN categories for Motor Vehicles. The CAPEX costs relating to this equipment group identification number were summed by regulatory year to provide the numbers for each group of equipment. The standard control services portion of motor vehicle costs was calculated by extracting from the Ellipse General Ledger a listing of all activity codes that have incurred an internal transport charge. This was then summarised into standard control, alternate control, isolated and non-regulated using the activity segment of the Ellipse coding structure. The proportion of total vehicle costs that relates to standard control services was then calculated. ***OTHER EXPENDITURE*** There is no capex for other expenditure as Ergon Energy's total non-network capital expenditure is reported against specific categories. Other Opex is the Other operating costs as per the relevant Performance RIN and includes items such as Customer Service, Solar

Minimum Requirements	Ergon Energy Response
	Bonus/ Feed-in tariffs, training, GSLs, Under/Over Absorbed Overheads, Non-network alternatives and debt raising costs after removal of overheads which are identified by a specific account code. ***OTHER NSP NOMINATED CATEGORIES*** ***Office Furniture & Equipment*** The capital expenditure on these items was sourced directly from previous Annual Performance RINs or QCA Regulatory Reporting Statements. As the capital expenditure is all by way of direct purchases and in accordance with the approved Cost Allocation Methodologies (CAM) these, in 2008/09 and 2009/10 did not incur overheads. In 2010/11, 2011/12 the direct costs were extracted from the relevant Annual Performance RIN. In 2012/13 where only total non-network overheads were shown the amount of overheads was determined by a pro rata. As these items are individually of low value Ergon Energy does not incur expenditure on their repair and maintenance, hence opex is shown as zero. ***Plant & Equipment*** This category includes all non-vehicle items of plant and equipment including ladders, portable generators and a wide variety of other items. In the Annual Performance RIN the motor vehicle category is used only for the actual vehicle and any vehicle mounted (eg cranes) is reported in the Plant & Equipment category. In the Category Analysis RIN motor vehicles and motor vehicle mounted equipment are to be reported in a single category. The numbers reported against the Plant & Equipment category are the total for Motor Vehicles plus Plant & Equipment (as per the Annual Performance RINS) after extracting motor vehicles and motor vehicle mounted equipment. ***Crane Borer Plant HCV*** The Opex cost of Crane Borer Plant HCV was based on an extraction of transport transactions from the relevant transport costing elements. The non-related opex transport costs were then removed. The remaining relevant transactions contain an equipment number. Crane Borer Plant HCV is represented by a specific equipment group identification number [G-FVPLCB]. The Opex costs relating to this equipment group identification number were summed by regulatory year to provide the numbers for the template. The Capex cost of Crane Borer Plant HCV was based on an extraction of transactions by equipment number and equipment group identification number [G-FVPLCB]. Crane Borer Plant HCV is represented by a specific equipment group identification number [G-FVPLCB]. The CAPEX costs relating to this equipment group identification number were summed by regulatory year to provide the numbers for the specific equipment group.

Minimum Requirements	Ergon Energy Response
	Other Fleet Assets Opex costs relating to EGI numbers for Trailers, Forklifts, Trenchers, Winchs, Cranes, Small generators (not Network Generators), Self-propelled EWP (not mounted to trucks), compressors, All Terrain Vehicles and Quad Bikes have been included in “other fleet assets”. These fleet assets are associated with specific equipment group identification (EGI) numbers. An extraction of transport transactions from the relevant transport costing elements was sourced. The non-related opex transport costs were then removed. The remaining relevant transactions contain an equipment number. The equipment number is attached to equipment group identification number. The transport transactions were then filtered to those relating to the specific EGI numbers associated to the above mentioned fleet assets. The Opex costs were then summed by regulatory year to provide the numbers for the template.. Capex costs relating to EGI numbers for Trailers, Forklifts, Trenchers, Winches, Cranes, Small generators (not Network Generators), Self-propelled EWP (not mounted to trucks), compressors, All Terrain Vehicles and Quad Bikes have been included in “other fleet assets”. The assets have specific equipment numbers which are attached to equipment group identification (EGI) numbers. The Capex cost of “other non-network Fleet assets” was based on an extraction of transactions from the relevant fleet Work In progress Activity accounts in the general ledger, with reference to the transport costing elements related to fleet equipment numbers in the general ledger equipment number and EGI Group. The transport transactions were then filtered to those relating to the specific EGI numbers associated to the above mentioned fleet assets. The Capex costs were then summed by regulatory year to provide the numbers for the template.
Use of Estimated Information	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER’s definition.
Why is it not possible to use Actual Information, and why an estimate is required	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER’s definition.
How the estimate has been produced	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER’s definition.

Table 2.6.2 Annual Descriptor Metrics – IT & Communications Expenditure

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.6, Table 2.6.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. In completing Table 2.6.2 – Non-Network Expenditure, Ergon Energy notes that it has: ▪ applied a simple average to determine the result where there were different values over the year; ▪ calculated user numbers based on active user accounts; ▪ calculated total client devices including hand held devices; ▪ scaled employee numbers, user numbers and number of devices in order to represent standard control services metrics only.
Use of Actual Information	Actual Information, in accordance with the AER's definition for Table 2.6.2, has been provided for the following variables. ▪ Employee numbers (2008/09 – 2012/13); ▪ User number (2008/09 – 2012/13); and ▪ Number of devices (2008/09 – 2012/13).
Source of Actual Information	Actual Information was sourced from: ▪ Annual stakeholder reports of Ergon Energy for Employee numbers. ▪ Software compliance reports For User numbers for 2008/09 - 2009/10; ▪ Microsoft Active Directory report for User numbers for 2010/11 - 2012/13; and ▪ System Centre Configuration Manager (SCCM) (Auto discover) and Active Directory for Number of devices. An SCS percentage was applied to underling data extracted. This was sourced from SCS% sourced from Template 2.10 Overhead workings (refer Basis of Preparation for Template 2.10).
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to request information from SPARQ Solutions who is the ICT provider for Ergon Energy. **Employee numbers** were sourced from annual stakeholder reports of Ergon Energy. **User numbers** for: ▪ 2008/09 - 2009/10 was sourced from the Software compliance reports; and ▪ 2010/11 - 2012/13 was sourced from the Microsoft Active Directory

Minimum Requirements	Ergon Energy Response
	report. ***Number of Devices*** The information was sourced using Microsoft applications - SCCM (Auto discover) and Active Directory. Microsoft Active Directory report - Active Directory is a Directory Service product produced by Microsoft and used by Sparq, Ergon Energy, and Energex to manage network user accounts and computer objects .All employees are given a user account within active directory. Underpinning the directory service is a database which contains unique identifiers for each object as well as various attributes associate with those objects. Reports are run against this database to determine the number of employees, active computers etc. SCCM (System Centre Configuration Manager) is a Microsoft product used for systems management. SCCM has the ability to auto discover devices on the network and determine what software etc. is running on them. Software compliance reports are produced using a variety of sources. SCCM is a primary source for the majority of software however other discovery tools (eg. Quest Discovery for databases) are used along with manual audits of applications based on vendor licensing models. An SCS percentage was applied to all source data to meet requirements of the RIN. The SCS% was sourced from Template 2.10 Overhead workings (refer Basis of Preparation for Template 2.10). The table below summarises the SCS% applied.

	2008/09	2009/10	2010/11	2011/12	2012/13
SCS %	79.32%	77.60%	79.42%	78.96%	72.13%

Minimum Requirements	Ergon Energy Response
Use of Estimated Information	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
How the estimate has been produced	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.

Table 2.6.3 Annual Descriptor Metrics – Motor Vehicles

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response</th></tr>
<tr><td></td><td>Ergon Energy has prepared the information provided in Template 2.6, Table 2.6.3 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

In completing Table 2.6.3 – Non-Network Expenditure, Ergon Energy notes that:
▪ Data has been scaled to ensure reporting relative to standard control services only;
▪ Ergon Energy has applied a simple average to determine the result where there were different values over the year.</td></tr>
<tr><td>Use of Actual Information</td><td>Ergon Energy has used Actual Information, in accordance with the AER’s definition, for:
▪ Average Kilometres Travelled (except 2008/09);
▪ Number purchased (Commissioned into service);
▪ Number Leased; and
▪ Number in Fleet.</td></tr>
<tr><td>Source of Actual Information</td><td>Actual Information for the variables was sourced:
▪ SG Fleet Annualised Quarterly Use Data (based on calendar months not financial year);
▪ Annual Review of Fleet Documentation</td></tr>
<tr><td>Methodology and assumption’s used in relation to Actual Information</td><td>In order to obtain the information, it was necessary for Ergon Energy to utilise the information contained in the annual reviews regarding Numbers purchased (Commissioned into service), numbers leased, number in fleet.

Average kilometres travelled was based on data from SG Fleet regarding quarterly annualised used reports.</td></tr>
<tr><td>Use of Estimated Information</td><td>Ergon Energy has used Estimated Information in relation to Average Kilometres Travelled for 2008/09 only</td></tr>
<tr><td>Why is it not possible to use Actual Information, and why an estimate is required</td><td>It was not possible to use Actual Information, and an estimate is required in relation to Average Kilometres Travelled for 2008/09 as accurate data was not available for that period.</td></tr>
<tr><td>How the estimate has been produced</td><td>In relation to Average Kilometres Travelled for 2008/09 only, Ergon Energy has developed an estimate based on utilised the figures applicable to the 2009/10 year.

Ergon Energy considers that the best estimate has been provided on the basis that the Average Kilometres Travelled has been relatively consistent for each of the following year periods and that the 2009/10 figures are representative.</td></tr>
</table>

Category Analysis RIN Basis of Preparation

Template 2.7 Vegetation Management

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.7 Vegetation Management of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.7 Vegetation Management (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.7 Vegetation Management, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

Furthermore, the below additional requirement/s were identified by Ergon Energy as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation. Responses to these requirements are made as attachment/s to this Basis of Preparation.

Table 1: Attachment/s to Basis of Preparation for Template 2.7 Vegetation Management

Notice Reference	Requirement	Attachments
Appendix E, paragraph 12.4 (a) – (b)	Provide individual maps showing each vegetation management zone (Ergon Energy has three zones), and A map showing the total network area with the borders of each vegetation management zone.	EECL 0913 CARIN_T2.7 VGMT A1 [Central] EECL 0913 CARIN_T2.7 VGMT A2 [Northern] EECL 0913 CARIN_T2.7 VGMT A3 [Southern] EECL 0913 CARIN_T2.7 VGMT A4 [Network]

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.7 Vegetation Management (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.7 Vegetation Management

Identifying Vegetation Management Zones

For the purposes of completing Template 2.7, Ergon Energy has identified **three** vegetation management zones across the geographical area of Ergon Energy's network. Importantly, each contiguous area nominated below is a vegetation management zone, and each part of the network is covered by only one vegetation management zone (i.e. non-overlapping).

In nominating Zones, Ergon Energy considered areas where costs are imposed by legislation, regulation or ministerial order, and areas of the network where other recognized drivers affect the costs of performing vegetation management work.

Prior to receipt of the final Category Analysis RIN, Ergon Energy had intended to provide information on the basis of eighteen Bioregions as its "vegetation management zones" to reflect the impact of rainfall and vegetation density on costs of performing vegetation management work. However, the decision to use the three management regions (Northern, Central, Southern) as the Category Analysis RIN "vegetation management zones" was made because Ergon Energy's vegetation management program is externally delivered in three separate contracts, one in each region. Ergon Energy has little variation in costs, compliance or restrictions imposed by legislations, regulations or ministerial orders within its network area, so it is the cost and composition of each of these contracts which are the greatest drivers affecting costs of performing vegetation management work.

The use of the three management regions as vegetation management zones allows for highly accurate reporting direct from existing databases, as the required information was already stored at the three region level within Ergon Energy's Ellipse enterprise planner and Artemis 7. This will also facilitate efficient and consistent reporting against required RIN variables into the future with respect to geographical zones. The RIN variables within each zone vary from those used by Ergon Energy to manage vegetation and while accuracy is auditable, the absence of direct alignment to RIN variables has resulted in many reported as estimates. This is particularly notable in costs ($) where all are recorded as estimates for this reason.

In accordance with Appendix E, Principles and Requirements paragraph 12.4 of the AER's Notice, Ergon Energy has provided as the attachments to this Basis of Preparation (refer above), individual maps showing each vegetation management zone and also a map showing the total network area with the borders of each vegetation management zone.

Regulations and Self-Imposed Standards Impacting Zones

As required by Appendix E, Principles and Requirements paragraph 12.7(a)-(b) of the AER's Notice, Ergon Energy notes the following summary of regulations (table 1) and self-imposed standards (table 2) impacting on all three Zones/Regions in Ergon Energy's network area.

Table 1: Regulations Impacting Zones

Regulations imposing a material cost on performing vegetation management works

- *Electrical Safety Act 2002*
- *Electrical Safety Regulation 2002*
- *Electricity Act 1994*
- *Environmental Protection Act 1994*
- *Nature Conservation Act 1992*
- *Nature Conservation (Protected Plants)*
- *Commonwealth Environmental Protection Biodiversity Conservation Act 1999*
- *Aboriginal Cultural Heritage Act 2003*
- *Fire and Rescue Act 1990*
- *Information Privacy Act 2009*
- *Agricultural Chemicals Distribution Control*

Regulations imposing a material cost on performing vegetation management works	
Conservation Plan 2000	*Regulation 1998*
▪ *Vegetation Management Act 1999*	▪ *QESI Powerline Code of Practice 2008*

Table 2: Self Imposed Standards Impacting Zones

Self-imposed standards applicable to Ergon Energy's vegetation management works
▪ EP12 Ergon Energy Environment and Cultural Heritage Policy
▪ ES000904R120 Ergon Energy Guideline for Management of Declared Plants
▪ ES000200R101 (Ver. 3) Ergon Energy Health Safety & Environment Improvement Plan 2012-2017
▪ NA000403R425 Guidelines for Monitoring Bushfire Weather Conditions, Fuel Conditions and Bushfire Danger Ratings
▪ SGNW0003Bushfire Mitigation Strategy
▪ STNW0602 Vegetation Clearance Profile Standard
▪ STNW0607 Standard for Vegetation Management
▪ STNW0707 Standard for Preventative Maintenance Programs
▪ STMM001 Standard for Vegetation Management Data Collection
▪ STNW0609 Standard for Vegetation Management Inspection and Assessment
▪ STNW0610 Standard for Vegetation Management Audit
▪ STNW06014 Standard for Negotiation for Removal or Herbicide Treatment of Unsuitable Trees
▪ STNW0616 Standard for Managing Vegetation Management Complaints
▪ AS 4373-2007 Pruning of Amenity Trees

Cost Impact of Regulations and Self-Imposed Standards on Zones

An explanation of the cost impact of the above regulatory and self-imposed standards is also required under Appendix E, Principles and Requirements paragraph 12.7(c) of the AER's Notice.

In this regard, Ergon Energy notes that the Regulatory impact on costs is the same across all Zones/Regions. Ergon Energy has limited external regulations that guide the maintenance of vegetation clearances from the network, compared to other NSPs.

Ergon Energy is required to maintain a safe and reliable network under section 148 of the *Electrical Safety Regulation 2002* through maintaining safe clearances between vegetation and power lines:

> *"An electricity entity must ensure that trees and other vegetation are trimmed and other measures taken, to prevent contact with an overhead electric line forming part of its works that is likely to cause injury from electric shock to any person, or, damage to property."*

Ergon Energy maintains this level of safety, as well as ensuring a level of power supply reliability, through a preventative maintenance style of vegetation management program which maintains adequate clearances between vegetation and the electrical network.

There is no bushfire risk mitigation legislation in Queensland specifically targeting NSPs such as Ergon Energy. The Queensland *Fire and Rescue Service Act 1990*, which is the key bushfire related legislation for

Queensland, does not specifically mention electricity NSPs. However, as a land manager Ergon Energy has an obligation to manage bushfire risks associated with its network and vegetation management practices. The risk of fire ignition from Ergon Energy electrical assets is minimised by ensuring that they are safe and properly designed, constructed and maintained. Vegetation management practices employed by Ergon Energy inherently do not increase bushfire risk, as slashing or other mechanical methods (which can cause sparks or dense regrowth and increased fuel levels) are typically not used, and vegetation density is typically decreasing or stabilising over time.

Ergon Energy's obligations and rights under the *Electrical Safety Regulation 2002* and *Electricity Act 1994* allow the operation of a vegetation management program that has exemption from a number of Queensland regulations, such as the Nature Conservation (Protected Plants) Conservation Plan 2000. In general, Queensland regulations relating to vegetation management recognise the highly disturbed nature of powerline corridors and do not impose overly complicated requirements in terms of surveys or herbicide application.

Where Ergon Energy's network enters State Forests or other Reserves, the Queensland Electrical Supply Industry (QESI) Code of Practice for Maintenance of electricity corridors in Queensland parks and forests (2008) determines that Ergon Energy must have an Environmental Work Plan (EWP) for maintenance activities to occur in these areas. Ergon Energy has also developed many Environmental Management Plans (EMPs) containing these EWPs, which are developed in collaboration with the tenure management authority. EMPs typically contain restrictions on treatment methods and clearance distances to reduce the impact of vegetation management on the location, including aesthetics. These areas, which are typically heavily vegetated, represent some of Ergon Energy's most expensive areas to manage vegetation clearances.

Ergon Energy's Vegetation Management Program

The frequency of inspection and treatment of vegetation is cyclical, triggering at a defined date based on determined treatment cycle length. Cycle lengths are variable across the network and are determined by the estimated vegetation growth rate of each Vegetation Zone, optimum timing to reduce long term costs, or how long the vegetation can remain untreated before it enters the Clearance Space surrounding conductors.

Vegetation Zones (VZs) are represented in Smallworld (Ergon Energy's Geographic Information System) as spatial polygons with defined boundaries based on feeder design and Bioregion classification.

The Clearance Space surrounding conductors is determined by conductor movement and arcing potential, and is variable based on network voltage. The required clearances are documented in Ergon Energy's Standard for Vegetation Clearance Profile (STNW0602).

Inspection and treatment of VZs are triggered and managed through the Ellipse ERP (Ergon Energy's Enterprise Management System) with asset-specific information stored against each VZ within Ellipse. This information includes how many poles and kilometres of line are within the VZ, line voltage, what bioregion the VZ is in, the cycle length that the VZ has been assigned, and the estimated treatment costs of managing vegetation within that VZ each cycle.

In recognition of the differences in treatment techniques required between urban and rural areas, VZs are distinctly split into rural and urban zones, with urban zones typically having shorter cycle times and less intrusive treatment techniques than rural zones.

Treatment methods used in urban areas are generally restricted to pruning and whole tree removal. Pruning is conducted wherever possible to AS 4373-2007 Pruning of Amenity Trees, which is designed to protect tree health. Where pruning is highly likely to negatively and permanently impact the health of a tree, or where the required clearance space cannot be maintained during the treatment cycle, removal of trees is preferred. Ergon Energy works with private owners and Local Government by providing adequate notice of intent, and to ensure such removals are agreed upon or reasons for removal are understood. Tree replacement costs are not captured separately to treatment costs.

Rural VZs are managed to a treatment “corridor” which maintains set distances around the network based on network voltage. Mature trees on the edges of the corridor are form pruned away from the network, while vegetation below the network is selectively managed to allow the retention of low and slow growing plant species. Preferred treatment methods for managing vegetation under the network are chemical-based and highly selective. These include spot foliar spraying, cut stump application, basal barking and stem injection. Some application of residual herbicide in pelletised or soil injection form is used in selected locations where permitted and where environmentally acceptable, to target undesirable woody vegetation.

Almost all inspection and treatment of vegetation is conducted by contractors engaged by Ergon Energy. A very small percentage of treatment work is done by appropriately trained depot staff during emergency situations or when vegetation is found to be posing unacceptable safety risk and is not planned to be treated in the vegetation management program within required remediation timeframes.

Visual assessment of vegetation presenting a potential hazard to the Ergon Energy overhead network is undertaken as part of the normal preventative maintenance for vegetation management. Similarly, overhang on distribution lines is not required to be removed on line voltages less than 33kV, unless shown to be obviously defective or hazardous.

It has been noted, Ergon Energy’s vegetation management program is demonstrating a continual reduction in average maintenance costs ($ per span). In short, this has been possible through:

- optimising the timing of treatment of each VZ based on location-specific maintenance cycles tuned for average rainfall and other environmental variables;
- enforcing contract requirements that ensure continued reduction in vegetation exposure (such as mandatory use of follow up herbicide wherever mechanical clearance was undertaken);
- targeted removal of incompatible vegetation in urban areas, often with collaboration with Local Government; and
- completion of previously neglected “backlog” areas between 2008/09 and 2012/13 using additional funding and contractor resources, allowing the whole Ergon Energy vegetation management program to move to a cost effective preventative cyclical style program.

Table 2.7.1 Descriptor Metrics by Zone

Table 3: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.7, Table 2.7.1 Descriptor Metrics by Zone, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER’s definition, for the Route line length for the period 2010/11 to 2012/13.
Source of Actual	Ergon Energy has sourced Actual information for Route line length for

Minimum Requirements	Ergon Energy Response
Information	the period 2010/11 to 2012/13 from Smallworld GIS;
Methodology and assumption's used in relation to Actual Information	***Route Line Length (km)*** *(P*eriod 2010/11 to 2012/13) In order to obtain the information, it was necessary for Ergon Energy to run a query within the Smallworld GIS to calculate the results per zone (Region). Approximately 10% of route line length was reported as "Undefined", without allocation to Urban/ CBD or Rural subcategories. To ensure consistency, the undefined line length value was divided between Urban/CBD and Rural for each zone, with half being attributed to Urban and half being attributed to Rural. This was an arbitrary allocation as a more accurate allocation was not possible.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables: ▪ Route line length for the years 2008/09 and 2009/10; ▪ Number of maintenance spans for the period 2008/09 to 2012/13; ▪ Total length of maintenance spans for the period 2008/09 to 2012/13; ▪ Length of vegetation corridors for the period 2008/09 to 2012/13; ▪ Average number of trees per maintenance span for the period 2008/09 to 2012/13; and ▪ Average frequency of cutting cycle for the period 2008/09 to 2012/13.
Why is it not possible to use Actual Information, and why an estimate is required	***Route line length:*** (2008/09 and 2009/10) It was not possible to use Actual Information, and an estimate is required in relation to this because Network Data staff were unable to source network length from Smallworld GIS prior to 2010/11. ***Number of Maintenance Spans:*** (period 2008/09 to 2012/13) It was not possible to use Actual Information, and an estimate is required in relation to Number of maintenance spans. Ergon Energy does not maintain data according to the RIN required disaggregation of 'Urban and CBD' and 'Rural'. Furthermore, Ergon Energy was not able to determine which spans completed as a part of the vegetation management program only had active management undertaken on it. However, Ergon Energy has historical records of span numbers completed by urban and rural program areas in its vegetation management program. Ergon Energy's urban and rural program areas spans data were used in all years to provide best estimated information in relation to the required 'Urban and CBD' and 'Rural' splits across all years. This data is considered to adequately represent the AER's intended desegregations. ***Total length of maintenance spans:*** (period 2008/09 to 2012/13) It was not possible to use Actual Information, and an estimate is required in relation to this because historical data on total length of

Minimum Requirements	Ergon Energy Response
	maintenance spans is not available within a database or historical report. Ellipse reporting of completed vegetation management works has historically only utilised number of spans completed, rather than line length. Using current line length of Ellipse ERP Vegetation Zones (VZs) and applied to VZs known to have been treated each year would result in inaccurate figures: VZ boundaries change and network configuration also changes over time, line length changes within each VZ as well. ***Length of vegetation corridors***: (period 2008/09 to 2012/13) It was not possible to use Actual Information, and an estimate is required in relation to this because historical data on length of vegetation corridors as defined in the AER RIN is not available within a database or historical report. ***Average number of trees per maintenance span:*** (2008/09 to 2012/13) It was not possible to use Actual Information, and an estimate is required in relation to Average number of trees per maintenance span because historical records of treatment work completed did not capture information according to the definition required. Figures used in the Benchmarking RIN 2014 for reporting average number of trees per maintenance span are not applicable using the definition provided for this Category Analysis RIN. This is because the figures used in the Benchmarking RIN include vegetation less than 3 metres in height. Ergon Energy's vegetation management program is heavily reliant on treating vegetation in rural areas under 3 metres in height, typically with herbicide, in order to minimise ongoing vegetation management costs. Treatment information captured by Ergon Energy, particularly in rural areas, is focussed on volume of work required to be completed (i.e. hectares and percentage application of herbicide) rather than the characteristics of vegetation treated. Of note, 2012/13 figures utilised the Roames LiDAR program data. These figures are considered to provide Best Estimates of the RIN required disaggregation's on the basis that the Roames data provides reports based on Ergon Energy's internally used and defined urban/rural splits, which adequately reflect the intent of the AER's RIN urban and CBD/rural disaggregation. The Roames LiDAR program has only been conducted since 2012/13. ***Average frequency of cutting cycle:*** (2008/09 to 2012/13) It was not possible to use Actual Information, and an estimate is required because historical cutting cycle records are not maintained in required RIN urban and CBD/rural disaggregation. For the figure used for Southern Region – rural, it was not possible to

Minimum Requirements	Ergon Energy Response
	use Actual Information, and an estimate is required given historical information from the Tree Management Database was not available for this location in 2008/09. An estimate was achieved through copying the figure recorded for 2009/10.
How the estimate has been produced	***Route line length***: *(2008/09 and 2009/10)* In relation to this variable Ergon Energy has developed an estimate based on the average of the actual figures used for 2010/11 to 2012/13 Ergon Energy considers that the best estimate has been provided for this variable on the basis that no other information is available to estimate this variable for the years 2008/09 and 2009/10. Furthermore, the average route line length during these years is expected to provide a reasonable proxy for route line length in previous years. ***Number of Maintenance Spans ('0s):*** *(*Period 2008/09 to 2012/13) In order to obtain information, it was necessary for Ergon Energy to source information from historical Ellipse ERP reports saved from the end of each financial year. Figures used are the actual number of spans maintained by vegetation management contractors in that year. Rural/Urban split was allocated based on Ergon Energy's urban and rural program management which varies where occurring inside or outside townships, This was considered a best available estimation methodology, with Ergon Energy's urban and rural program areas adequately meeting the intent of requirements to provide disaggregation reflective of short or long rural feeder construction boundaries. Figures provided represent total number of spans found within Vegetation Zones (VZ) completed/treated in each year. This includes spans that no actual vegetation treatment occurred (such as valleys or agricultural land). Elimination of spans where no treatment had occurred was not possible due to lack of accurate captured information and large errors that occur through applying averages or estimates to span totals. Planned Roames LiDAR refinement will allow very accurate reporting in the future through understanding of numbers of spans which require treatment each year. Between 2008/09 and 2012/13 Ergon Energy undertook a "backlog" completion program as part of efforts to get vegetation management costs under control and move towards maintaining vegetation clearances in a true variable cyclic program. The backlog completion program involved dramatically increasing the size of the program compared to prior to 2008/09 to treat areas of the network which had previously not been maintained for up to ten (10) years due to lack of budget or poor program delivery. Due to contract delivery timing, completion of vegetation management on maintenance spans mainly occurred during 2009/10 and 2011/12.

Minimum Requirements	Ergon Energy Response
	Total Length of Maintenance Spans (period 2008/09 to 2012/13) Ergon Energy has developed an estimate whereby Line length was estimated through assuming 4 spans per kilometre of network in rural areas, and 25 spans per kilometre in urban areas, and so number of spans was divided by these ratios to obtain line length for each Region. In developing this estimate, Ergon Energy has made the following assumptions: ▪ There are an average of 25 spans per kilometre of network in urban areas; ▪ There are an average of 4 spans per kilometre of network in rural areas; and These estimates of averages are consistent with the route line length and average cutting cycle frequency and supported by Roames liDAR data Ergon Energy considers the best estimate has been provided on the basis that historical information on line length treated is not available and calculation using current line length found within each VZ does not allow accurate reflection of changes made to maintenance zone boundaries, line configuration nor proportion of work area completed. The assumptions used to calculate the length of maintenance spans are consistent with the total route line length and average cutting cycle frequency. ***Length of Vegetation Corridors:*** (period 2008/09 to 2012/13) Ergon Energy has developed an estimate whereby Urban figures were copied directly from the urban “length of maintenance spans” variable for urban areas. Similarly, rural figures were copied directly from the rural “length of maintenance spans” variable for rural areas. In developing this estimate, Ergon Energy has made the assumption that vegetation corridors are approximately the same as maintenance spans in terms of length. Ergon Energy considers the best estimate has been provided for this variable on the basis that: ▪ Information in line with the AER definition of vegetation maintenance corridor is not available in historical records or able to be interpreted from the Smallworld GIS. ▪ Spans in which no vegetation maintenance is conducted due to reasons referenced by the AER (e.g. terrain or land use) is not known or currently able to be accurately estimated. ▪ More accurate figures are not able to be accurately estimated using alternative methods, such as in field sampling, given the large size of the overhead network and variability of the environment. ***Average Number of Trees per Maintenance Span:***

Minimum Requirements	Ergon Energy Response
	Ergon Energy has developed an estimate for years prior to 2012/13 based on an approach whereby each year references the figure in the following year and adds 10%. Figures represent a 10% increase each year prior to 2012/13. In developing this estimate, Ergon Energy has made the assumptions that a 10% reduction in exposure to trees each year from 2008/09 to 2012/13, based on actual figures recorded for 2012/13. Ergon Energy considers the best estimate has been provided for the average number of trees per maintenance span on the basis that: ▪ A main aim of the Ergon Energy vegetation program is to reduce exposure to vegetation. ▪ Removal of unsuitable vegetation is promoted within urban areas. ▪ Rural maintenance cycles have become increasingly tailored to vegetation growth rates and optimum timing for herbicide treatment of regrowth prior to vegetation becoming a “tree” as per the AER definition. This is resulting in fewer trees to manage within the rural corridor. ▪ The Ergon Energy / Greening Australia Plant Smart public education program has been running since 2003 and teaches customers not to plant inappropriate trees near powerlines. ▪ Vegetation management costs are steadily declining each year on a per span basis. ▪ A 10% reduction in tree numbers per year was chosen to reflect the level of improvement in vegetation management practices and standards compliance. This will be accurately available going forward with the implementation of programmed LiDAR information and management processes. For 2012/13 figures, it was necessary for Ergon Energy to run a report using the Roames aerial LiDAR program analytics report system. The Roames report was not able to be used prior to 2012/13 as the capability was not previously available prior to 2012/13. For Rural proportions, the value was calculated using the number of objects reported in all rural program areas within the maintenance corridor that are equal to or greater than 3 metres in height, divided by the total number of spans reported by Roames to that point in time for that Region. No duplication of location capture has occurred yet, so results represent the average number of objects found within this area across the whole network. For Urban proportions, the value was calculated for each Region using the total number of objects reported in all urban program areas in the Region within 3 metres of the clearance space applied to the Ergon Energy network, and objects greater than or equal to 3 metres in height, divided by the total number of spans reported by Roames to that point in time for that Region.

Minimum Requirements	Ergon Energy Response
	Assumptions for using Roames LiDAR results include: ▪ Objects reported within defined area are assumed to be vegetation, but may include non-vegetation objects or dead vegetation. ▪ Urban/rural split is in line with Ergon Energy's program urban/rural split and maintenance zones which represent work types applied within or outside townships. ▪ Around 5% of the network had not been reported by Roames at time of reporting. This remaining 5% is located in Southern Region, thereby potentially skewing results slightly if remaining areas are not similar to the 95% assessed. The possible effect is unknown at this stage. ▪ Figures used in 2012/13 include information captured in 2013/14, but represent the first data capture "pass" of the Ergon Energy network which took 18 months to complete between November 2012 and March 2014 and should provide a good assessment of vegetation exposure during 2012/13. ***Average Frequency of Cutting Cycle:*** (2008/09 to 2012/13) ▪ In order to obtain the information for 2008/09 to 2011/12, it was necessary for Ergon Energy to use historical data from the Tree Management Database to measure the time between records of completed treatment work on vegetation maintenance zones. ▪ Within each nominated Category Analysis vegetation management zone (Region), there are multiple treatment cycle lengths and multiple instances of historical treatment events. Averages of these inter-treatment time periods (treatment cycle lengths) were measured for each zone (Region). This calculation can include records of "touch up" or intra-cycle treatment works conducted prior to scheduled treatment timing, meaning that cycle lengths may appear shorter than scheduled. The effect of this on total average cycle lengths is not known. The trend reported is consistent with expectations. ▪ Information for 2012/13 was sourced from Ellipse as vegetation data capture improvements have facilitated the transfer of more accurate information into Ellipse ERP. ▪ Number of Maintenance Spans was sourced from Ellipse ERP historical reports; ▪ Average Number of Trees per Maintenance Span was sourced from a Roames aerial LiDAR program analytics report; ▪ Average Frequency of Cutting Cycle was sourced from the Tree Management Database for 2008/09 to 2011/12 and from Ellipse ERP reporting for 2012/13. ▪ Specific to the Average Frequency of Cutting Cycle (Southern

Minimum Requirements	Ergon Energy Response
	Region- Rural) (2008/09) o Ergon Energy reported an estimate based on the figure recorded for 2009/10. In doing so, it was assumed that the average cycle for 2008/09 is likely to be similar to the following year 2009/10. o Ergon Energy considers the best estimate has been provided on the basis that current maintenance cycles are greater in length in this location compared to 2008/09, so current cycles should not be applied to areas completed during this time. Furthermore, it is most conservative to apply the figure from 2009/10 to obtain the approximate value for 2008/09.

Table 2.7.2 Expenditure Metrics by Zone

Table 4: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.7, Table 2.7.2 Expenditure Metrics by Zone, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables.
Methodology and assumptions used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables.
Use of Estimated Information	Estimated Information for variables was sourced from Ergon Energy's Ellipse and Artemis 7 systems, which provides the collation of the detail to work type task level.
Why is it not possible to use Actual Information, and why an estimate is required	Ergon Energy does not maintain records at the required level of disaggregation and so used suitable figures from Ellipse and Artemis 7 to produce best endeavours estimates.
How the estimate has been produced	In order to provide information, it was necessary for Ergon Energy to aggregate cost categories within the defined variables. In doing so, it is noted that: **Tree Trimming** includes all urban vegetation management contract costs. Alignment of Urban Vegetation Management (Ergon Energy) and Tree Trimming (CA RIN) is made because the strategy and delivery

Minimum Requirements	Ergon Energy Response
	methodology are essentially founded on trimming of vegetation. This varies from Rural Vegetation Management (Ergon Energy) which is founded on clearance the corridor using methods other than trimming – e.g. chemical treatment **Hazard Tree Cutting** includes all unplanned Guaranteed Service Level (GSL) costs associated with customer call responses. GSL costs are typically associated with internal depot staff or external contractor staff attending customer call outs to trim vegetation which poses a safety or reliability risk. **Vegetation Corridor Clearance** includes all Rural vegetation management program costs. Alignment of Rural Vegetation Management (Ergon Energy) and vegetation Corridor Clearance (CA RIN) is made because the strategy and delivery methodology are essentially founded on clearance of the line corridor of vegetation. This varies from Urban Vegetation Management (Ergon Energy) which is founded on tree trimming **Ground Clearance** costs are captured by Ergon Energy as Access Track maintenance and as such are recorded into Template 2.8 Maintenance. **Inspection** includes all survey costs associated with Urban and Rural vegetation management programs. This is a collation of survey (inspection) costs reported as Tree Trimming (Urban) and Vegetation Corridor Maintenance (Rural) as described above. **Audit** - Ergon Energy does not incur any direct costs associated with audit due to costing models and practices implemented. Accordingly, zeroes are reported. **Contractor Liaison Expenditure** - Ergon Energy does not incur any direct costs associated with contractor liaison due to contracting models and asset standards implemented. Accordingly, zeroes are reported. **Tree Replacement Program** costs represent the costs associated with the Plant Smart educational partnership that Ergon Energy has with Greening Australia Pty Ltd. For more information, see https://www.ergon.com.au/your-home/safety-at-home/trees-and-powerlines/plant-smart. Plant Smart costs not only include tree replacement costs, but also the other costs associated with running the program (such as contractor staff costs and promotional material) A Regional breakdown of figures provided for 2008/09 and 2009/10 was not captured by Ergon Energy and as such, a percentage attributable to each Region was calculated using the actual percentages attributable that occurred in 2010/11. With the program of works consistent across these years, it is reasonable to make this assumption.

Table 2.7.3 Descriptor Metrics Across All Zones - Unplanned Vegetation Events

Table 6: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	For all initial regulatory years in Table 2.7.3, Descriptor Metrics across all zones – Unplanned Vegetation Events, cells are shaded Orange, indicating an exception to the requirement to report where Ergon Energy does not currently collect of report this information (refer paragraph 1.3(j) of Appendix E Principles and Requirements). Furthermore, it is noted in requirements specific to the Unplanned Vegetation Events Table (refer paragraph 12.17), that Ergon Energy is not required to provide information requested in table 2.7.3 for the initial regulatory years where it does not currently have it and may shade the cells black. Ergon Energy currently does not collect or report this information and accordingly has shaded cells black.

Category Analysis RIN Basis of Preparation

Template 2.8 Maintenance

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.8 Maintenance of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.8 Maintenance (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.8 Maintenance, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.8 Maintenance (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.8 Maintenance

Table 2.8.1 - Descriptor Metrics for Routine and Non-Routine Maintenance

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.8 - Maintenance, Table 2.8.1 - Descriptor metrics for routine and non-routine maintenance in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has limited reporting in Template 2.8 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. This results in reporting of maintenance for public lighting for the years 2008/09 and 2009/10 only. As the provision of maintenance for street lighting services was reclassified as an Alternative Control Service from 1 July 2010 associated costs and therefore metrics have not been reported for years thereafter (2010/11 – 2012/13) in Table 2.8.1. In completing Table 2.8.1 - Descriptor metrics for routine and non-routine maintenance, Ergon Energy notes that: ▪ Where tasks were carried out for simultaneous inspection of assets and vegetation or for access track maintenance, this expenditure is reported under maintenance (not vegetation management) ▪ Ergon Energy has inserted additional Maintenance Asset Categories o Communications, Meters and Ancillary Costs under the *Various Assets*':, to represent costs incurred for routine and non-routine maintenance of communications and metering equipment and for the costs associated with rates, leases , rents and electricity charges for asset sites - Zone Substations and Communications sites. No units of measure were provided as this category captures a multitude of information not included in existing CA RIN categories. This is required for completeness of reflection of all routine and non-routine maintenance costs o Access Tracks under Ground Clearance to represent tasks completed for routine and non-routine maintenance for access tracks along and adjacent to rural lines These maintenance expenditure subcategories were added as it is material and not yet included in any other maintenance expenditure

Minimum Requirements	Ergon Energy Response
	subcategory. ▪ Ergon Energy does not have any Dual Function assets, therefore records no *Subtransmission asset maintenance – for DNSPs with Dual Function Assets*. Accordingly, all metrics are reported as Zeroes. ▪ All metrics are reported as zeroes in relation to *Zone Substation Equipment Maintenance*, for asset sub category *Transformers - HV* because all Zone Substation Transformers are reported within variable Transformers – Zone Substation ▪ Ergon Energy does not have any CBD feeders in its network, therefore all metrics in relation to *Network Underground Cable Maintenance: By Location* on asset subcategory *CBD feeders* is reported as zeroes. ▪ Furthermore Ergon does not carry out any routine maintenance on underground cables therefore maintenance quantities as reported relate to non-routine maintenance only. ▪ For all other variables the reporting of zero indicates that there was not maintenance performed in relation to that variable for that particular year. This is due to asset strategy change within the reporting period to start a new maintenance program or suspend or cease an existing one. ▪ Ergon Energy has recorded planned Maintenance Cycles as allowable under the AER definitions. It should be noted that delivery to cycle was approaching 100 %(97.4% average across all asset groups) in 2012/13 thus reporting planned cycles is appropriate.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Use of Estimated Information	Estimated Information for variables was sourced from Ergon Energy's core systems on the basis of: ▪ Asset Quantity for the Period - Smallworld GIS ▪ Asset Quantity Maintained – Ellipse and Artemis 7 ▪ Asset Av Age – Smallworld GIS
Why is it not possible to use Actual Information, and why an estimate is required	In the case of variables Asset Quantity for the Period and Asset Av Age there is sufficient data disparity within Smallworld GIS presently to classify records as best endeavour estimates. For variable Asset Quantity Maintained, Ergon Energy does not maintain records at the required level of disaggregation and so used

Minimum Requirements	Ergon Energy Response
	suitable collation of actual figures from Ellipse and Artemis 7 to produce best endeavours estimates. Ergon Energy has developed an estimate whereby Line length was estimated through assuming 4 spans per kilometre of network in rural areas, and 25 spans per kilometre in urban areas, and so number of spans was divided by these ratios to obtain line length for each Region. In developing this estimate, Ergon Energy has made the following assumptions: ▪ There are an average of 25 spans per kilometre of network in urban areas; ▪ There are an average of 4 spans per kilometre of network in rural areas; and ▪ These estimates of averages are consistent business assumptions and supported by Roames liDAR data ▪ This is used to derive the unit of measure (kilometer line length) required of CA RIN category as opposed to that measured in Ergon Energy systems (spans).
How the estimate has been produced	***Asset Quantity At Year End*** In relation to Asset Quantity Ergon Energy has developed an estimate on the following basis: ▪ 2010/11 to 2012/13 – Direct output from Smallworld GIS disaggregated to align with best endeavours to CA RIN categories ▪ 2008/09 to 2009/10 - Reducing the last known year (2010/11) by 1.6% per year being % growth used in Ergon Energy's maintenance models and accepted by AER at that time, And representing a more accurate representation of asset quantity at year end. This is due to the poor level of accuracy in system sourced data on asset quantity at year end for years 2008/09 and 2009/10. ▪ On this basis Ergon Energy considers that the best estimate has been provided ▪ An assumption has been used to determine the 'number of poles' for 'pole tops and overhead lines' and 'all poles'. Ergon's assumption is that for every 'pole top' there must be an associated pole, and thus the asset quantity at year end should be the same value for these two variables. ▪ An assumption has been used to determine the quantities for 'earth mats' against the asset category 'distribution substation - other equipment'. For every "installed transformer" for "distribution substation transformers", there must be an "earth mat" therefore these quantities should be the same. Similarly the number of distribution substation properties maintained has been assumed to be consistent with the quantities of installed transformers.

Minimum Requirements	Ergon Energy Response
	▪ It is noted that an assumption has been used to determine the number of distribution transformers within zone substations. Ergon have assumed that each zone substation has a distribution transformer, thus the asset quantity at year end must be equal to all zone substation properties. ***Asset Quantity Maintained*** In relation to Asset Quantity Maintained (Routine), Ergon Energy has developed an estimate on the following basis: ▪ 2010/11 to 2012/13 – Direct output from Ellipse and Artemis 7 disaggregated to align with best endeavours to CA RIN categories Ellipse captures information down to work type task level and Artemis 7 provides collation of this into nominated programs of work. ▪ 2008/09 to 2009/10 – Proportioning quantities maintained and cost incurred from last known year to actual costs for 2008/09 and 2009/10 this being a more accurate representation of asset quantity maintained. This is due to the poor level of accuracy in system sourced data on asset quantity maintained for years 2008/09 and 2009/10. On this basis Ergon Energy considers that the best estimate has been provided as described above and that that no change to asset strategy or delivery methodology was made across those years. In relation to Asset Quantity Maintained (Non-Routine), Ergon Energy has developed an estimate on the following basis: ▪ 2012/13 – Direct output of costs at GL Activity from Ellipse disaggregated to align with best endeavours to CA RIN categories ▪ Ellipse captures information at a higher level (GL Activity) than for routine maintenance (Work Task Type). This means that Ergon Energy assessed proportionate numbers of work orders across the CA RIN categories from that higher level Ellipse collected data. ▪ The proportions disaggregated to CA RIN category are based on assessment of non routine costs for 2012/13 and number of work orders applied across known costs for years 2008/09 to 2011/12. The proportions used to disaggregate 2012/13 costs we derived through manual scrutiny of individual work orders created against the GL Activities. Ergon Energy considers that the best estimate has been provided on the basis that no change to asset strategy or delivery methodology was made across those years. ***Asset Average Age***

Minimum Requirements	Ergon Energy Response
	In relation to Asset Quantity Ergon Energy has developed an estimate on the following basis: ▪ 2010/11 to 2012/13 – Direct output from Smallworld GIS disaggregated to align with best endeavours to CA RIN categories. This variable is included as estimated due to the attributes captured within Smallworld GIS not aligning directly with CA RIN categories therefore some disaggregation involved collation of similar assets into different CA RIN lines. Ergon Energy has used the highest value asset type in the asset group as a basis. ▪ Data quality on asset age has improved across the years 2010/11 to 2012/13 with the number of assets with the asset age attribute available increasing. This means that the numbers of older assets added to dataset far exceeded the numbers of new assets added. The result is that the annual snapshot of asset average age is greater and most accurate for 2012/13 ▪ 2008/09 to 2009/10 - Reducing the last known year (2010/11) by 1 year based on this being a more accurate representation of average asset age. This is due to the poor level of accuracy in system sourced data on asset average age for years 2008/09 and 2009/10. On this basis Ergon Energy considers that the best estimate has been provided.

Table 2.8.2 - Cost Metrics for Routine and Non-Routine Maintenance

Table 2: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Blacked out cells	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
Consistency with the requirements of the Notice	Ergon Energy has prepared the information provided in Template 2.8 - Maintenance, *Table 2.8.2 - Cost metrics for routine and non-routine maintenance* in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has limited reporting in Template 2.8 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. This results in reporting of maintenance for public lighting for the years 2008/09 and 2009/10 only. As the provision of maintenance for street lighting services was reclassified as an Alternative Control Service from 1 July 2010 associated costs have not been reported for years thereafter (2010/11 – 2012/13) in Table 2.8.2. Furthermore, the total amount for this table has been reconciled with the total maintenance expenditure for Standard Control Services as classified in the year reported. In completing *Table 2.8.2 - Cost metrics for routine and non-routine maintenance*, Ergon Energy notes that: ▪ Where expenditure was incurred for simultaneous inspection of assets and vegetation or for access track maintenance, this expenditure is reported under maintenance (not vegetation management) ▪ Ergon Energy has inserted additional Maintenance Asset Categories o Communications, Meters and Ancillary Costs under the *Various Assets*':, to represent costs incurred for routine and non-routine maintenance of communications and metering equipment and for the costs associated with rates, leases , rents and electricity charges for asset sites - Zone Substations and Communications sites. o Access Tracks under Ground Clearance to represent costs incurred for routine and non-routine maintenance for access tracks along and adjacent to rural lines These maintenance expenditure subcategories were added as it is material and not yet included in any other maintenance expenditure subcategory. ▪ Ergon Energy does not have any Dual Function assets, therefore records no *Subtransmission asset maintenance – for DNSPs with*

Minimum Requirements	Ergon Energy Response
	Dual Function Assets. Accordingly, all metrics are reported as Zeroes. ▪ All metrics are reported as zeroes in relation to *Zone Substation Equipment Maintenance*, for asset sub category *Transformers - HV* because all Zone Substation Transformers are reported within variable Transformers – Zone Substation ▪ Ergon Energy does not have any CBD feeders in its network, therefore all metrics in relation to *Network Underground Cable Maintenance: By Location* on asset subcategory *CBD feeders* is reported as zeroes.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information in relation to all variables across all years in the table.
Use of Estimated Information	Estimated Information for variables was sourced from Ergon Energy's core systems on the basis of: ▪ Routine Maintenance - Ellipse and Artemis 7 ▪ Non-Routine Maintenance - Ellipse and Artemis 7
Why is it not possible to use Actual Information, and why an estimate is required	For variable Routine Maintenance and Non-Routine Maintenance, Ergon Energy does not maintain records at the required level of disaggregation and so used suitable collation of actual figures from Ellipse and Artemis 7 to produce best endeavours estimates.
How the estimate has been produced	***Routine Maintenance*** In relation to Routine Maintenance, Ergon Energy has developed an estimate on the following basis: ▪ 2010/11 to 2012/13 – Direct output of costs per work task from Ellipse and Artemis 7 disaggregated to align with best endeavours to CA RIN categories Ellipse captures information down to work type task level and Artemis 7 provides collation of this into nominated programs of work. ▪ 2008/09 to 2009/10 – Proportioning quantities maintained and cost incurred from last known year to actual costs for 2008/09 and 2009/10. This is due to the poor level of accuracy in system sourced data on asset quantity maintained for years 2008/09 and 2009/10. On this basis Ergon Energy considers that the best estimate has been provided as described above and that that no change to

Minimum Requirements	Ergon Energy Response
	asset strategy or delivery methodology was made across those years. ***Non-Routine Maintenance*** In relation to Non-Routine Maintenance, Ergon Energy has developed an estimate on the following basis: ▪ 2012/13 – Direct output of costs at GL Activity from Ellipse disaggregated to align with best endeavours to CA RIN categories Ellipse captures information at a higher level (GL Activity) than for routine maintenance (Work Task Type). This means that Ergon Energy assessed proportionate levels of expenditure across the CA RIN categories from that higher level Ellipse collected data. The proportions disaggregated to CA RIN category are based on assessment of non routine costs for 2012/13 applied across known costs for years 2008/09 to 2011/12. The proportions used to disaggregate 2012/13 costs we derived through manual scrutiny of individual work orders created against the GL Activities. Ergon Energy considers that the best estimate has been provided on the basis that no change to asset strategy or delivery methodology was made across those years.

Category Analysis RIN Basis of Preparation

Template 2.9 Emergency Response

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.9 Emergency Response of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.9 Emergency Response (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.9 Emergency Response, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.9 Emergency Response (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.9 Emergency Response

Table 2.9.1 Emergency Response Expenditure (OPEX)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.9, Table 2.9.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Regard has also been given to the AER's confirmation that where the instructions for template 2.9 ask for: (A) Total emergency response opex (B) Opex for major event (defined) and for major storms (defined) (C) Opex for MEDs (defined). Note: For years prior to STPIS reporting, Ergon Energy has applied criteria supplied by the AER during this CA RIN reporting period to specify MEDs during those years the AER noted that: ▪ (B) is intended to capture costs where they can be attributable to particular events whereas (C) is to reflect all emergency response opex on days that were MEDs. ▪ The RIN instructions ultimately result in a double reporting of costs in (B) and (C) where an event for example, triggers an MED however AER expect to have visibility of opex on a daily basis under item (C) where the MED event is identified. ▪ AER also wouldn't necessarily expect daily opex for events identified in (C) to sum up to amounts reported for the same event in (B) given other activity on those days.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for all variables in Table 2.9.1 for the period (2008/09 to 2012/13).
Source of Actual Information	Actual Information for the variables was sourced from Ergon Energy's ERP – Ellipse.
Methodology and assumption's used in relation to Actual Information	In respect of (B) MAJOR EVENTS O&M EXPENDITURE ($000'S), Ergon Energy notes: ▪ In order to obtain the information, it was necessary for Ergon Energy to select work orders from ERP (Ellipse); ▪ Ergon Energy's Ellipse Code for Forced Maintenance (54100) has

Minimum Requirements	Ergon Energy Response
	been used as it aligns to the AER's definition of Emergency Response. ▪ Data represents the total emergency response expenditure attributed to major events (clarified by the AER to mean an event triggering a 'major event day' - a term that is defined in the STPIS), including costs extending prior and past associated declared MED days as well as costs associated with Major Storms of Category 1 or above (but not necessarily result in an MED). ▪ These costs are calculated by accessing ERP (Ellipse) data contained in work orders created specifically for capture of costs for the specifically listed events. These work orders capture and collate all transactions applicable to the listed events In respect of (C) MAJOR EVENT DAYS O&M EXPENDITURE ($000'S), Ergon Energy notes: ▪ In order to obtain the information, it was necessary for Ergon Energy to select transactions from ERP (Ellipse) for each day identified as an MED. ▪ Emergency response expenditure incurred on the specific MED was reported by identifying daily operating expenditure incurred on each date. ▪ A sum of the emergency response expenditure incurred across the MED days related to a specific event was also calculated. ▪ Although consistent with the AER's guidance in this regard, Ergon Energy notes that under this approach, data reported: o captures total emergency response on these dates not only for abnormal events but also for normal daily events; o does not capture the total emergency response associated with the abnormal event which caused the MED but incurred in prior, or subsequent non-MED days.
Use of Estimated Information	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
How the estimate has been produced	Not applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.

Category Analysis RIN Basis of Preparation

Template 2.10 Overheads

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.10 Overheads of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.10 Overheads (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.10 Overheads, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.10 Overheads (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.10 Overheads

Table 2.10.1 - Network Overheads Expenditure

Table 1: Addressing Minimum BOP requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.10, Table 2.10.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Overhead expenditure has been reported before it is allocated to services (Alternative Control Services (ACS) or Standard Control Services (SCS)) or direct expenditure, and before any part of it is capitalised. Furthermore, regard has been given to the guidance provided from the AER in its Issues register, noting that Network Overheads has six compulsory categories and allowance for other (new) nominated categories (i.e. a new basis, break from previous Annual Performance RINs);
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual information and an estimate is required in relation to Network Overheads. Overheads applied are not disaggregated into Network and Corporate nor are they disaggregated at the mandatory categories within Network Overheads. Information at the level required is neither recorded nor traceable in the accounts of Ergon Energy. Overhead recoveries are also reconciled throughout the year with adjustments to allocations made as required to fully recover overheads for the year. Ergon Energy has used its best endeavours to estimate allocation of network overheads.
How the estimate has been produced	Network Overheads have been estimated by applying the underlying methodology of the Cost Allocation Method (CAM) and Ergon Energy's

Minimum Requirements	Ergon Energy Response
	associated overhead processes to actual support costs to derive an indicative breakdown of actual overheads across the Network Overheads categories. In order to obtain the information, it was necessary for Ergon Energy to apply the following assumptions and methodologies: **<u>Source Data</u>** Base data sourced from Mincom Ellipse Reporting System (MERS) *Trial Balance* report to return net support costs (or "overhead") for each of the initial regulatory years. Net support costs form the basis of the overhead pool. Report parameters are set as follows: ▪ District: EECL (Ergon Energy Corporation Limited) – the distribution entity; ▪ Responsibility Centre (RC): All (Business Unit groups responsible for expenses for a function/location) ▪ Activity: 62000 to 65040 (Type of work being undertaken, this range captures all "overhead" activities) ▪ Product: All (Product or service being provided) ▪ Element: 3300 to 8370 (excluding 8115, 8120CL, 8350, 8355) (Nature of the expense, this range captures all "overhead" elements) Resulting data represents the total "overhead" by RC by year. **<u>Allocation to Overhead Category</u>** Each RC has been allocated to an overhead category within either Network Overheads or Corporate Overheads (AER defined terms), based on professional judgement as to the most appropriate category for each RC. This allocation is applied consistently across all five initial regulatory years. As required, data currently reported as 'Network Operating Costs' in Ergon Energy's Annual Performance RIN has been collated / mapped to Network Overheads in the Category Analysis RIN, and disaggregated into the six mandatory subcategories: ▪ network management ▪ network planning ▪ network control and operational switching ▪ quality and standard functions (including standards and manuals, compliance, quality of supply, reliability, network records (GIS), and asset strategy (other than network planning) ▪ project governance and related functions (including supervision, procurement, works management, logistics and stores) ▪ other (including training, OH&S functions, network billing, and customer service).

Minimum Requirements	Ergon Energy Response
	Other expenditure categories reflect annual reporting, with each category reported appropriately under Network Overhead. Specific categories that have been reported in the Overheads template which are normally treated as direct costs by Ergon Energy are: ▪ Network Operating costs ▪ Meter Reading ▪ Customer Service ▪ Feed-in Tariff/Solar Bonus ▪ Non-network Alternatives ▪ Training and ▪ Other Costs **<u>Disaggregation by SCS, ACS, Unregulated Service Classifications</u>** Network Overheads have been disaggregated across Standard Control Services (SCS), Alternative Control Services (ACS) and Unregulated Services classifications (Ergon Energy has no Negotiated distribution services) based on the Cost Allocation Method and Classification of Services applicable to the year of reporting as well as an internal overhead model to determine the percentage allocation of each RC across the service types. Excluded Services for the prior regulatory period have been treated as ACS for classification purposes. This allocation has been calculated using 2012/13 year data only and this allocation has then been applied across the five years. **<u>Capitalised Overheads</u>** Capitalised overheads have been calculated in accordance with Ergon Energy's current CAM and previous CAMP (QCA approved Cost Allocation Methods and Procedures) and consistent with the capitalisation policy which has not changed over the period. While the total capitalised overhead for 08/09 and 09/10 is consistent with the CAMP and previously reported RIN, allocations are an estimate only given they are done on the basis of the 12/13 CAM. Ergon Energy considers it prudent to allocate overheads to Capital expenditures due to the size and nature of the capital expenditures. Capital expenditure is a key driver for the incurring of overheads and to not allocated overheads would undervalue the true cost of the Capital program. **<u>Reconciliation</u>** The above allocation is not exact an apportionment has been applied to reconcile total Opex and total Capital overheads to previously reported RIN totals. This has been achieved by pro-rating disaggregated values by year.

Table 2.10.2 - Corporate Overheads Expenditure

Table 2: Addressing Minimum BOP requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 2.10, Table 2.10.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Overhead expenditure has been reported before it is allocated to services (ACS or SCS) or direct expenditure, and before any part of it is capitalised.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual information and an estimate is required in relation to Corporate Overheads. Overheads applied are not disaggregated into Network and Corporate nor are they disaggregated at the mandatory categories within Corporate Overheads. Information at the level required is neither recorded nor traceable in the accounts of Ergon Energy. Overhead recoveries are also reconciled throughout the year with adjustments to allocations made as required to fully recover overheads for the year. Ergon Energy has used its best endeavours to estimate allocation of corporate overheads.
How the estimate has been produced	Corporate Overheads have been estimated by applying the underlying methodology of the CAM and Ergon Energy's associated overhead processes to actual support costs to derive an indicative breakdown of actual overheads across the Corporate Overheads categories. In order to obtain the information, it was necessary for Ergon Energy to apply the following assumptions and methodologies: **<u>Source Data</u>** Base data sourced from Mincom Ellipse Reporting System (MERS) *Trial Balance* report to return net support costs (or "overhead") for each of the initial regulatory years. Net support costs form the basis of the

Minimum Requirements	Ergon Energy Response
	overhead pool. Report parameters are set as follows: ▪ District: EECL (Ergon Energy Corporation Limited) – to capture distribution costs; ▪ Responsibility Centre (RC): All (Business Unit groups responsible for expenses for a function/location) ▪ Activity: 62000 to 65040 (Type of work being undertaken, this range captures all “overhead” activities) ▪ Product: All (Product or service being provided) ▪ Element: 3300 to 8370 (excluding 8115, 8120CL, 8350, 8355) (Nature of the expense, this range captures all “overhead” elements) Resulting data represents is the total “overhead” by RC by year. **<u>Allocation to Overhead Category</u>** Each RC has been allocated to an overhead category within either Network Overheads or Corporate Overheads (AER defined terms), based on professional judgement as to the most appropriate category for each RC. This allocation is applied consistently across all five initial regulatory years. **<u>Disaggregation by SCS, ACS, Unregulated Service Classifications</u>** Corporate Overheads have been disaggregated across Standard Control Services (SCS), Alternative Control Services (ACS) and Unregulated Services classifications (Ergon Energy has no Negotiated distribution services) based on the CAM and Classification of Services applicable to the year of reporting as well as internal overhead model to determine the percentage allocation of each RC across the service types. Excluded Services for the prior regulatory period have been treated as ACS for classification purposes .This allocation has been calculated using 2012/13 year data only and this allocation has then been applied across the five years. **<u>Capitalised overheads</u>** Capitalised overheads have been calculated in accordance with Ergon Energy’s current CAM and the QCA approved CAMP and is consistent with the capitalisation policy which has not changed over the period. While the total capitalised overhead for 08/09 and 09/10 is consistent with the CAMP and previously reported RIN, allocations are an estimate only given they are done on the basis of the 12/13 CAM. Ergon Energy considers it prudent to allocate overheads to Capital expenditures due to the size and nature of the capital expenditures. Capital expenditure is a key driver for incurring of overheads and to not allocate overheads would undervalue the true cost of the Capital program. **<u>Reconciliation</u>** The above allocation is not exact. A true up has been applied to

Minimum Requirements	Ergon Energy Response
	reconcile total SCS and total Capital overheads to previously reported RIN totals. This has been achieved by pro-rating disaggregated values by year.

Category Analysis RIN Basis of Preparation

Template 2.11 Labour

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.11 Labour of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.11 Labour (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.11 Labour, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.11 Labour (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.11 Labour

Table 2.11.1 – Cost Metrics per Annum

Table 2.11.2 – Extra Descriptor Metrics for Current Year

Table 1: Addressing Minimum BOP requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. In exception to this, Ergon Energy has not separately reported Labour Hire and Employee costs under each classification level. This information is deemed as "optional" in Tables 2.11.1 and 2.11.2. Ergon Energy has entered "zeroes" in the following labour classifications for all years: ▪ "*Intern, Junior Staff, Apprentice Non Electrical*" - Ergon Energy doesn't have these types of employees; and ▪ "*Skilled Non Electrical Worker*" - Ergon Energy does not have trades other than Electrical based trades for SCS activity. There is no duplication of costs between the Corporate Overhead, the Network Overhead and the Direct Network Activity. Also of note, Ergon Energy has labour costs which are not catered for by the lines provided in Template 2.11 Labour, tables 2.11.1 and 2.11.2. These have been included in the template by merging them with other Labour Classifications as follows: ▪ White collar workers labour costs that should be categorised as Direct Network labour costs (given the Ergon Energy practice for all employees who engage in Direct Network Activity to cost to the activity regardless of Labour classification) have been included in the Skilled Electrical Worker classification.
	Ergon Energy has prepared the information provided in Template 2.11, table 2.11.1 Cost Metrics per Annum and table 2.11.2 Extra Descriptor Metrics for Current Year in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Only labour costs relating to the provision of Standard Control Services are reported in the Template.
Use of Actual Information	Not applicable - Ergon Energy has provided Estimated Information, in accordance with the AER's definition – refer below.
Source of Actual Information	Not applicable - Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Methodology and assumption's used in relation to Actual	Not applicable - Ergon Energy has provided Estimated Information, in accordance with the AER's definition.

Minimum Requirements	Ergon Energy Response
Information	
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition for all variables in Table 2.11.1 Cost Metrics per Annum for all initial regulatory years and Table 2.11.2 Extra Descriptor Metrics for Current Year (2012-13).
Why is it not possible to use Actual Information, and why an estimate is required	Actual Information for the variables was sourced from Ergon Energy Ellipse ERP system. Specifically the HR Employee data, Financial GL balances $ and Hours and Payroll. However, material gaps in employee data from 2012/13 payroll employee data mean costs were unable to be allocated to cost centre or Labour classification. These gaps relate to terminated employees and are due to the business process of removing all costing and resource information for the terminated employee. Furthermore, Leave, Super and Payroll Tax data (by employee) is not available from Ergon Energy source systems for 4 of the 5 initial regulatory years requested in the AER's Notice. Refer to the methodology and assumptions, and source of data used in preparing data for Template 2.11 as detailed below. Ergon Energy considers that it has used its best endeavours to provide a best estimate of information given the data available, and the disaggregation's required by the AER as prescribed by the templates and definitions.
How the estimate has been produced	In order to report the information, it was necessary for Ergon Energy to undertake a number of steps as detailed below: **1. Allocate Ergon Employees to RIN Labour Classifications** In order to allocate Ergon Energy employees into RIN labour classifications levels required it was necessary to assume that certain combinations of Ergon Energy employee resource categorisations combined to equal / were mapped to specific AER's defined labour Classifications levels. Where mapping to RIN classifications was not clear or was not deemed appropriate based on Ergon Energy's resource information, SME judgement was applied. Resultant employee classifications are provided in the table below.

RIN Classification	Ergon Classifications
Apprentice	Electrical Apprentice
Executive	Chief Executive & Executive General Managers
Senior Manager	Generalist Manager responsible for managing multiple managers
Manager	Generalist Managers responsible for project teams or staff
Professional	Non Generalist Prof & Managerial positions
Semi Professional	Para Professional, System Control & Operator, Designer
Skilled Electrical Worker	Field Work Group Leader, Technical Service Person & Power Worker
Support Staff	Administration & Administration Supervisors

Data as at 30 June 2013 data was used to establish the employee to RIN Labour

Minimum Requirements	Ergon Energy Response
	Classification. This data was then used as the basis of allocating payroll data to RIN Labour classifications by cost centre for all years. Ergon Energy confirms quantities of labour, expenditure or stand down periods are not reported multiple times across the tables. **2. Determine RIN Labour Classification % Split for Labour payroll costs and hours per Responsibility Centre** Of note, Employee payments from Ergon Energy's Payroll system are not able to be used for the purposes of the RIN. Ellipse Payroll data only contains two financial years of data, with older data archived and not accessible. Furthermore, when an employee leaves the business all details of the employee regarding resource type and cost centre are deleted. Accordingly, detailed 2012/13 employee payroll data is considered to have materially incomplete data for up to 19% of employees. Ergon Energy therefore used the 2012-13 payroll costs for active employees only as at June 30 as a basis for determining labour costs associated with the RIN labour classifications. Using only active employees produced a 99% correlation with available Ellipse HR Employee costing & resourcing data for the corresponding year. Cost Centre splits by RIN Labour Classification were achieved by combining the June 2013 employee RIN Labour classification data with the 2012-13 Payroll data, both costs and hours, for all active employees at June 2013. This provided the Allocation assumptions for Payroll Labour costs and hours. This assumption basis was the most appropriate as it provided an allocation based on the lowest granularity of costing data available ie employee and payroll costing. No other methodology was deemed suitable given the data constraints. The determined 2012/13 Allocation %'s were applied to all financial years, given the data constraints noted above. The 2012/13 allocations were considered to be representative of the allocations in previous years This is the best estimate based on available information and SME discussion. **3. Allocate Non Labour costs to Cost Centre and RIN Labour categories** Ellipse GL annual balances were used as source data for the remainder of the Other costs. Ordinary Labour hours per cost centre per RIN Labour Classification (see above) were used to allocate Other costs. It was assumed that Ordinary hours worked represented the consumption driver in this regard as this reflected the physical employee numbers that would consume these costs in the normal day to day running of the business. **4. Determine SCS component of cost centre and RIN Labour classification costs and hours** SCS Opex % and SCS Capex % were determined as part of the RIN Overhead workings (refer Basis of Preparation for Template 2.10) and combined to determine a Total SCS % for each cost centre. The Total SCS% was unique to each year.

Minimum Requirements	Ergon Energy Response
	This Total SCS% was applied to the aggregate costs and hours per cost centre and per RIN labour classification to calculate the SCS component for populating the RIN Labour template variables. This basis was used as it was not possible to determine an alternate allocation methodology based on data constraints & reporting capability. **5. Direct costed (work order related) Direct Network costs and hours** The direct costed SCS Network activity that is classified as Network Overhead by the RIN guidelines (eg Customer Services, Network Operations, Demand Management) has been deemed as duplicated costs and excluded from the Direct Network section of the Labour template. This cost & associated hours is already included in the Overhead sections. The remainder of the direct costed SCS Network activity has been determined using the following process. Ellipse Labour costs and hours were sourced from work order transactions for activity defined as SCS Network Overhead activity or Direct Network Overhead activity. Total Direct Network costs and hours were allocated as per step 1 above to achieve an estimate of cost by Labour Classification. As the Overhead costs are based on total payroll costing they implicitly contained the hours and costs of employees that book time to Direct Network activity. This Direct Network portion of the overhead costs was removed by reducing the Overhead cost with the Direct Network cost by labour classification.. This basis was used as it was not possible to determine an alternate methodology due to data constraints & reporting capability. **6. Leave, Workers Comp, Super and Payroll Tax costs** Ergon Energy was required to use Corporate Oncost rates data to estimate Leave, Workers Comp, Superannuation and Payroll Tax costs: ▪ The Ergon Energy corporate Oncost Rates applied in each financial year were used as the basis for estimating the Leave, Workers Comp, Superannuation and Payroll Tax amounts. Each of these costs has its own Oncost rate. ▪ The Oncost rates applicable to each regulatory year were applied. ▪ The rates were applied as per Ergon Energy Ellipse costing rules – i.e. Oncost Rate % multiplied by specific Labour expense(s). These costs were determined by cost centre and RIN Labour classification by applying the rate to the cost centre & labour classification payroll data. This basis was used as it was not possible to determine an alternate methodology due to data constraints & reporting capability. **7. Labour Hire** Ergon Energy did not apply the option of showing Labour Hire separately. Instead these costs and hours were included in the Overhead categories and Labour classification in which it was incurred.

Minimum Requirements	Ergon Energy Response
	Labour Hire $-cost (annual balances) data was sourced from the Ellipse GL for all five years. No source of data was available for hours or Labour classification. Accordingly, it was necessary to apply a Cost centre SCS GL Labour Hire costs / Average Rate Assumption. ▪ An average rate for Support or Managerial was determined using current Supplier Panel information. ▪ Rates were de-escalated by CPI to determine an average rate for each financial year. The following Labour Classification assumption / mappings were required: ▪ White collar professional type costs centre - Manager ▪ All other cost centres – Support Staff This basis was used as it was not possible to determine an alternate methodology due to data constraints & reporting capability. **8. Redundancies** Redundancy costs have been included in the 2011-12 & 2012-13 years. Prior to these years the amounts were not material in value and have not been included. The costs have been included using the actual payments and estimated employee payments. These have then been allocated to RIN Labour classifications using the methodology outlined in the above sections. **9. Stand Down Occurrences** Due to the data and reporting constraints detailed in the above sections, detailed stand down occurrence data was not available for all years. Count of stand down occurrence data was only available for the 2012-13 year. Therefore an estimation process was required to populate all five years. A gross Ergon Energy $ per stand down occurrence rate was determined by combining the 2012-13 GL cost centre financial data and the Payroll stand down occurrence claimed data. The 2012-13 estimated stand down $ rate was de-escalated for annual EBA price movements to achieve a rate for the 2008-09 to 20011-12 years. These annual rates were applied to the annual GL cost centre financial stand down data to determine an estimated number of stand down occurrences. Based on the process above the number of stand down occurrences were determined for each RIN year and labour classification. The SCS portion of this total stand down occurrence count was determined by the application of the cost centre SCS % as per the Overhead allocations. All White collar worker Stand Downs were allocated to overheads. The Skilled Electrical Worker & Apprentice Stand Downs were allocated to Direct Network Activity. This allocation was as per step 1 above.

Minimum Requirements	Ergon Energy Response
	10. Calculation based on assumption of 1880 hours per FTE ASL Ergon Energy's normal business reporting uses the FTE assumption of 1880 hours or 9 day fortnight engagement. This is based on the fact that that 67% of Ergon Energy employees are engaged on a 9 day fortnight basis. The ASLs for each classification Level reflect the average paid FTEs for each classification level over the course of the year. This allowed for the calculation of the number of ASL as follows: $\frac{\text{(SCS Ordinary Hours + SCS Overtime Hours)}}{\text{1880 hours}}$ **11. Calculate Per ASL Values** ▪ **Average Productive Work Hours per ASL(0'S)** was calculated as: $\frac{\text{(Ordinary Hours + Overtime Hours)}}{\text{ASL count}}$ ▪ Productive Work hours equals the total of the SCS Ordinary Time hours and the SCS overtime hours ie Total SCS hours. ▪ **Stand-Down Occurrences per ASL (0'S)** is the number of stand down occurrences, per annum per labour category / ASL count. ▪ **Stand-Down Occurrences** were sourced from Ellipse payroll data. ▪ **Average Productive Work Hours per ASL-Ordinary Time (0'S)** is calculated as *Ordinary Time Hours / ASL Count.* ▪ **Average Productive Work Hours Hourly Rate per ASL-Ordinary Time (0'S)** represents - *Ordinary Time Cost / Ordinary Time Hours* ▪ **Average Productive Work Hours per ASL-Overtime (0'S)** represents - *Overtime Hours / ASL count* ▪ **Average Productive Work Hours Hourly Rate per ASL-Overtime** represents - *Overtime Cost / Overtime Hours.* ▪ **Total Labour Cost** is the *aggregation* of all costs. These calculations represent the most appropriate alignment of Ergon Energy source data with the variables prescribed within the RIN requirements.

Category Analysis RIN Basis of Preparation

Template 2.12 Input Table

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 2.12 Input Table of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 2.12 Input Table (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 2.12 Input Table , Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 2.12 Input Table (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 2.12 Input Table

Table 2.12 Input Table

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 12.1 Table 12.1 Input Tables in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. It is noted that Table 12.1 Input Tables does not represent an exhaustive list of expenditure. The summation of input costs for each category do not reconcile to total expenditures amounts reported in all respective templates given limitations of the template. It is also noted there are no requirements in the RIN regarding reconciliation that involve template 2.12. ▪ Within the Ergon Energy group, the parent entity Ergon Energy Corporation Limited (EECL) maintains controlling interest over three reporting entities. These include Ergon Energy Queensland Pty Limited (EEQ) and Ergon Energy Telecommunications Pty Limited (EET) which are both 100% owned, and a jointly controlled entity SPARQ Solutions Pty Ltd (SPARQ) where Ergon Energy maintains a 50% ownership interest. EEQ is a non-competing electricity retailer; EET is a wholesale telecommunication service provider; and SPARQ is an information, communications and technology service provider. ▪ EECL provides management services to its subsidiaries. Accordingly, EEQ and EET do not have their own management structures. EECL pays SPARQ a charge in accordance with service level agreements which is captured as a corporate overhead. ▪ EECL is subject to common control as a Queensland Government Owned Corporation (GOC), with all shares held by shareholding Ministers on behalf of the State of Queensland and transacts with other State of Queensland controlled entities. However, the Queensland Government and State of Queensland controlled entities are not considered related parties for the purposes of the CA RIN due to the specific exclusion of government departments in the definition. ▪ Ergon Energy did not identify any Related Parties contract expenditure in relation to direct capital and operating expenditure. ▪ EECL's corporate overheads and non-network IT and communications costs include related party costs incurred from

Minimum Requirements	Ergon Energy Response
	SPARQ. As SPARQ operates on a cost pass through model, there are no Related Party Margins to report.
Use of Actual Information	Not applicable - Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Source of Actual Information	Not applicable - Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Methodology and assumption's used in relation to Actual Information	Not applicable - Ergon Energy has provided Estimated Information, in accordance with the AER's definition.
Use of Estimated Information	Ergon Energy has provided Estimated Information, in accordance with the AER's definition for all variables in Table 2.12 Input Tables for all initial regulatory years.
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. There are also material gaps in employee data from 2012/13 payroll employee data mean costs were unable to be allocated to cost centre or Labour classification. These gaps relate to terminated employees and are due to the business process of removing all costing and resource information for the terminated employee. Furthermore, Leave, Super and Payroll Tax data (by employee) is not available from Ergon Energy source systems for 4 of the 5 initial regulatory years requested in the AER's Notice. As a result, Ergon Energy has provided Estimated Information, in accordance with the AER's definition for all variables in Template 2.11. This has meant that Ergon Energy is only able to provide estimated information for Template 2.12. Ergon Energy considers that it has used its best endeavours to provide its best estimate of direct material cost, direct labour cost, contract cost and other costs based on the available data and the AER Category Analysis RIN's definitions.
How the estimate has been produced	Base data sourced from Ellipse was used to establish a total and the initial split between direct material cost, direct labour cost, contract cost and other costs. Cost elements within the chart of accounts were used to allocate costs between direct material cost, direct labour cost, contract cost and other costs. The cost elements were not sufficiently detailed to provide the correct costs to meet the Category Analysis RIN's definition for direct labour cost, contract costs and other costs, because direct labour is recorded at average standard labour cost rates (not actual incurred payroll costs) and reconciled in aggregate. The estimates for the labour data compiled for Template 2.11 were used to adjust labour costs in Template 2.12 for corporate, network and directly allocated overhead and direct labour costs in order for them to balance to the labour costs shown in Template 2.11.

Minimum Requirements	Ergon Energy Response
	Within Ergon Energy's chart of accounts labour hire is classified as contract costs. The proportion of labour hire to total contract costs was calculated based on the proportion of labour hire that is classified as contract costs. Contract costs were then reduced by this proportion. Other costs were then calculated as a balancing item after deducting direct material cost and the adjusted totals for direct labour costs and contract costs. This ensured that the row totals remained unchanged. No apportionment was required to be made for direct material cost. It was identified within the base data sourced from Ellipse using specific cost elements. The following costs, which have been included within other templates, were not included in the Template 2.12: ▪ Total emergency response expenditure [contained in Template 2.9. Emergency Response]; ▪ Plant & Equipment [contained in Template 2.6 Non network]; ▪ Office Furniture & Equipment [contained in Template 2.6 Non network]; ▪ Fleet Hire Costs [contained in Template 2.6 Non-Network]. Crane Borer Plant HCV [contained in Template 2.6 Non network]; and Other fleet assets [contained in Template 2.6 Non network] were mapped to Motor Vehicle line item in the Inputs tab. These costs were not included because additional line items could not be inserted into Template 2.12.

Category Analysis RIN Basis of Preparation

Template 4.1 Public Lighting

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 4.1 Public Lighting of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 4.1 Public Lighting (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 4.1 Public Lighting, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirement/s were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 4.1 Public Lighting (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 4.1 Public Lighting

Table 4.1.1 - Descriptor Metrics for Current Year (2012/13)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 4.1 - Public Lighting, Table 4.1.1 - Descriptor metrics for current year (2012/13) in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. As advised by the AER, Ergon Energy has not had regard to paragraph 17.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN. Data has not been reported in relation to gifted assets, or public lighting services which have been classified as contestable. However, non-contestable, regulated public lighting services reported includes work performed by third parties on behalf of Ergon Energy. Finally, Ergon Energy does not have negotiated services in relation to public lighting therefore no metrics are included in this regard.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 4.1.1 for the period 2012/13
Source of Actual Information	Actual Information for the variables was sourced from Smallworld. Smallworld is a geographical information system and provides information in relation to spatial location of distribution and subtransmission network including public lighting.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to extract data from the Smallworld report, RIN 2013_07 reporting tables – rin_2013_07_01_report@eainspr1.db.ergon:1523/eainspr1. The following variables/ validations were used: ▪ Lights must have a valid geometry ▪ Lights to be 'as constructed' (in-service) ▪ Ergon Energy built and owned (Rate 1) only lights to be included ▪ Billable 'is null' or 'Yes' ▪ Lights in the 'billing dump' have been excluded ▪ Light counts have been grouped per construction Some constructions may now be superseded but were valid as at the snapshot date and are still included in the count. Lights with invalid descriptions (124 lights) were entered as SLM80D lights. This is based on previous audit experience of lights with

	unknown descriptors being found to be of the M80 category. In the 2013/14 financial year Ergon Energy completed an external audit on all Streetlights which is in the process of being compiled and validated. The new software program Lightmap by Geomatic Technologies will be introduced in 2014/15 and will be the future source of all Public Lighting asset counts. The outcomes of the audit could result in a notable change in quantities reported in future CA RIN's.
Use of Estimated Information	Not applicable. Ergon Energy has provided Actual Information in relation to Table 4.1.1.
Why is it not possible to use Actual Information, and why an estimate is required	Not applicable. Ergon Energy has provided Actual Information in relation to Table 4.1.1.
How the estimate has been produced	Not applicable. Ergon Energy has provided Actual Information in relation to Table 4.1.1.

Table 4.1.2 - Descriptor Metrics Annually (Volumes and Expenditure)

Table 2: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. Ergon Energy has left blank, the cells for *Volume of GSL Breaches* and *GSL Payments*. Ergon Energy does not have a GSL scheme for Public Lighting, and is therefore not required to report data in respect of GSLs. However the cell is not shaded orange for blacking out as per instructions. Given a 'zero' is a valid and logical answer, but no scheme exists for Ergon Energy, it is not appropriate to enter 'zero'.
	Ergon Energy has prepared the information provided in Template 4.1 - Public Lighting, Table 4.1.2 - Descriptor metrics annually in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has not distinguished between expenditure for public lighting services between Standard and Alternative Control Services when completing Template 4.1 Table 4.1.2. Furthermore, expenditure has not been distinguished between capex and opex. This was further clarified by the AER in its issues register, where it noted that all items of capex and opex that were necessary to provide the services listed in templates 4.1 to 4.4 were to be included. In this regard, costs have been measured as the direct cost, excluding overheads.

Minimum Requirements	Ergon Energy Response
	Expenditure has been reported as a gross amount, by not subtracting customer contributions. Furthermore, data has not been reported in relation to gifted assets, or public lighting services which have been classified as contestable. However, non-contestable, regulated public lighting services reported includes work performed by third parties on behalf of Ergon Energy. Finally, Ergon Energy does not have negotiated services in relation to public lighting therefore no metrics are included in this regard.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's definition, for: ▪ Volume of Customer Complaints for the period 2008/09 – 2012/13 ▪ Total Public Light Maintenance Expenditure for the period 2008/09 – 2012/13
Source of Actual Information	Actual Information for Volume of Works and Expenditure was sourced from Ellipse, whereas Actual Information for Volume of Customer Complaints was sourced from FACTS.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information for **Volume of Customer Complaints**, it was necessary for Ergon Energy to report only negative feedback from FACTS and exclude other forms of feedback including positive feedback and enquiries. Information for **Total Public Light maintenance** expenditure was directly obtained from Ellipse activity codes directly related to the maintenance of public lighting assets. A report was run from Ellipse with an extract of the general ledger costs for Streetlighting Opex. This included the total and breakdown costs for activity codes of: ▪ 53180 – Corrective Regulated Streetlights ▪ 52180 – Preventive Regulated Streetlights ▪ 54200 – Forced Regulated Street Light Maintenance. The Direct Cost (without overheads) value was summarised for each financial period.
Use of Estimated Information	Ergon Energy has used Estimated Information in relation to the following variables ▪ Light Installation – Volume of Works and Expenditure 2008/09 – 2012/13 ▪ Light Replacement – Volume of Works and Expenditure 2008/09 – 2012/13 ▪ Light Maintenance– Volume of Works 2008/09 – 2012/13 ▪ Mean Days to rectify/replace Public Lighting assets (days) for the period 2008/9 – 2012/13
Why is it not possible to	It was not possible to use Actual Information, and an estimate is

Minimum Requirements	Ergon Energy Response
use Actual Information, and why an estimate is required	required in relation to ▪ Light Installation (volume or works and expenditure), Replacement (volume of works and expenditure) and Maintenance Volume of Works 2008/09 – 2012/13 because the corporate ERP and associated processes were not envisioned or configured with the level of detail requested by the AER in mind. Processes within Ergon Energy that result in asset replacement are conducted as mixed bundles of differing asset classes. Thus the ability to directly access the individual costs of each asset replaced does not exist. ▪ Mean Days to rectify/replace Public Lighting assets because FeederSTAT does not record Public Lighting outages as a reportable category.
How the estimate has been produced	In relation to **Light Installation Major/ Minor and Poles Volume**, Ergon Energy has developed an estimate based on the following approach: It was necessary for Ergon Energy to apply a stock code to all items to reflect what that item was used for. An Ellipse report was run to identify transactions associated with the key stock items with a street light stock section. Transactions were filtered to remove activities for external work and internal movements between stores. The following activity codes were identified as related to Ergon Energy's key New Streetlight Installation activity: ▪ C2050 – Other Regulated System Capex ▪ C2060 – Domestic & Rural Customer Requested Works ▪ C2070 – Commercial & Industrial Customer Requested Works ▪ C2080 – Other Customer Requested Works ▪ C2120 – Street Lighting Constructed A new report called "RIN Reporting Requestioning Data Streetlighting Capital" has been built to pick up the volume of Streetlight components issued from Stores and the material cost associated with the above activity Codes for each financial period. Major Luminaires, Minor Luminaires and all poles values were then totalled for the respective volume subcategory provided. The data collected was only for regulated, non-contestable streetlights as per the RIN definition. In relation to **Light Installation Total Cost**, Ergon Energy has developed an estimate based on the following approach: ▪ The General Ledger Direct totals for Activity Code C2120 Street Lighting Constructed were reported for each financial period. ▪ The materials costs reported in the "RIN Reporting Requestioning Data Streetlighting Capital" for Luminaires, Lamps, Poles and

Minimum Requirements	Ergon Energy Response
	Brackets from Activity Codes C2050, C2060, C2070 and C2080 were added for these totals. ▪ Ergon Energy has been unable to identify if other Direct Costs that were not materials had been used for Streetlight Installations under these Activity Codes. Ergon Energy considers that the best estimate has been provided for Light Installation Expenditure and Volume but concerns are held as we are unable to accurately verify the number of light installations as opposed to the number of jobs against what is believed to be representative of a true figure. This estimate has used the best available data and that is being reviewed and could change in the future once we better understand factors such as whether some are multiple light installations in a single job, or whether costs are being represented elsewhere in other Activity Codes. In relation to **Light Replacement Major/ Minor and Poles Volume**, Ergon Energy has developed an estimate based on the following approach which is the same data from RIN Template 2.2, Table 2.2.1: Replacement Expenditure Volumes: ***Plant Cost Allocation Method*** 1) The total expenditure on Asset Replacement (by financial year) is taken from the General Ledger using the three (3) activity codes which align with this activity: These codes are: **Activity Code** / **Description** C2000 / Network Refurbishment C2020 / Ageing Asset Replacement C2130 / Street Lighting Refurbishment 2) Network Refurbishment refers to the process of refurbishing a major part of the network like a feeder or a zone substation by replacing its subordinate parts. 3) That portion of Asset Replacement expenditure associated with the **asset group - Lines and Distribution Plant (poles, pole tops, conductor, cable, services, distribution transformers, distribution switchgear and street lighting)** has been determined from ‘J Code’ combinations. 4) For each asset category the number of asset replacements for each financial year is determined from stores issues of the key plant item allocated to the activity codes from step 1. The key plant items counted are those stores items that become the asset category item once installed. In some cases a ratio is applied to convert the stores issue quantity to the asset quantity e.g. 3,000 metres of single core UG 11kV cable becomes one (1) circuit kilometre of “> 1 kV & < = 11 kV UNDERGROUND CABLE”. For unitised assets like poles or distribution transformers the ratio is 1:1.

Minimum Requirements	Ergon Energy Response
	5) The "plant cost" for each asset category is taken as the total stores issue cost for the key plant item for each financial year is extracted from the Ellipse inventory module. 6) For the **asset group - Lines and Distribution Plant**, the expenditure for the financial year is calculated as the proportion of the ratio of the plant cost for the particular key plant item of all key plant items in the group times the total direct cost expenditure for the asset group. Using this ratio the total expenditure costs are apportioned appropriately to the each asset category. In developing this estimate, Ergon Energy has made the assumptions that: ▪ All replacement expenditure is allocated across the Asset Categories in Table 2.2.1. ▪ The ratio of material costs to other direct costs (labour etc.), is consistent across assets. ▪ There is sufficient volume in each asset class to smooth price fluctuations (this has been made difficult by the AER groupings) Ergon Energy considers the best estimate has been provided for the yearly EXPENDITURE on the basis that actual total expenditure and inventory information has been used to estimate the asset category expenditure and spot calibration where the unit plant cost is reviewed and plant weightings altered by the SME to ensure that the value is consistent with their experience. In the case of the public lighting, plant weightings have been adjusted to set the total expenditure for 2012/13 to approximate the expenditure seen against activity code C2130, as this recently introduced code is now considered fully operational. In the absence of actual data, Ergon Energy considers that stores issue costs associated with the asset provides a good proxy for the distribution of other costs associated with installing the asset. In relation to **Light Maintenance Major/ Minor and Poles Volume**, Ergon Energy has developed an estimate based on the following approach: ▪ Variables were sourced from Ergon Energy's ERP – Smallworld and Ellipse systems. ▪ Direct extracts from end of year activity reports of maintenance unit quantities were used to complete the required subcategories of Major and Minor Lights and Poles. This included Bulk Lamp Replacement and Road Patrol programs. In relation to **Mean Days to rectify/replace Public Lighting assets**, Ergon Energy has developed an estimate based on the following approach: ▪ Ellipse reporting of number of days for Streetlight Work Orders between creation and close-out of work order (actual information). Note that this will not necessarily be a proper

Minimum Requirements	Ergon Energy Response
	reflection if there is an extended period between when work is completed and the Work Order is closed out. Field Force Automation will address this. ▪ Work orders for Road Patrol, materials, negative days, no end date and non-lamp related work where identified and have been removed. ▪ Data entered into FeederSTAT was unable to be extracted. These are for ‘rectify/replace’ of critical infrastructure and is completed 80% of the time on the day reported which means a true average would be below that estimated. Ergon Energy considers that the best estimate has been provided for Light Installation, Replacement and Maintenance Volumes and Expenditures on the basis that: ▪ Further filtering of available information is not available to define the required parameters; ▪ The information sources are the most accurate available within Ergon Energy’s reporting systems. Ergon Energy considers that the best estimate has been provided for Mean Days to rectify/replace Public Lighting assets on the basis that: ▪ Further filtering of available information is not available to define the required parameters; and ▪ The average number of days between creation and close-out of Streetlight Work Orders is expected to provide a reasonable proxy for Mean Days to rectify/replace Public Lighting assets.

Table 4.1.3 - Cost Metrics (Average Unit Cost)

Table 3: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 4.1 - Public Lighting, Table 4.1.3 - Cost metrics in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has not distinguished between expenditure for public lighting services between Standard and Alternative Control Services when completing Template 4.1. Furthermore, expenditure has not been distinguished between Capex and Opex. This was further clarified by the AER in its issues register, where it noted that all items of Capex and Opex that were necessary to provide the services listed in templates 4.1 to 4.4 were to be included. In this

Minimum Requirements	Ergon Energy Response
	regard, costs have been measured as the direct cost, excluding overheads. Expenditure has been reported as a gross amount, by not subtracting customer contributions. Furthermore, data has not been reported in relation to gifted assets, or public lighting services which have been classified as contestable. However, non-contestable, regulated public lighting services reported includes work performed by third parties on behalf of Ergon Energy. Finally, Ergon Energy does not have negotiated services in relation to public lighting therefore no metrics are included in this regard
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in accordance with RIN requirements for all variables.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information in accordance with RIN requirements for all variables.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information in accordance with RIN requirements for all variables.
Use of Estimated Information	Ergon Energy has used Estimated Information in relation to Average Unit Cost for Major and Minor Light Installation, Replacement and Maintenance for 2008/09 – 2012/13
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to Average Unit Cost for Major and Minor Light Installation and Replacement for 2008/09 – 2012/13 as Energy reporting systems do not report to the individual unit expenditure level. Capital expenditure (Installation and Replacement) was able to use unit volumes that were relatable back to materials and direct expenditure. Light Maintenance averages did not have a direct relationship between recorded asset volumes and associated activity codes and only an overall average was able to be calculated.
How the estimate has been produced	Ergon Energy has developed an estimate based on the following approach: **Average Unit Cost for Major and Minor Light Installation and Replacement for 2008/09 – 2012/13** Several Reports were run from Ellipse to provide primary information on : ▪ Volume of lamps, luminaires, brackets and poles linked to Installation / Replacement Activity Codes for each period by breakdown into Major/ Minor grouping and light type subcategory ▪ Average cost of lamps, luminaires, brackets and poles linked to Installation / Replacement Activity Codes for each period by breakdown into Major/ Minor grouping and light type subcategory

Minimum Requirements	Ergon Energy Response
	▪ General Ledger information for the ratio of Material Cost to Direct costs for Installation (2120) and Replacement (2130) activity codes. An average weighted volume methodology was used to calculate the number of major components (lamps, luminaires, brackets and poles) used in an average installation or replacement of major and minor streetlights. The data was extracted from Ellipse requisitioning data for respective activity codes used for Installations and Replacements. Ergon Energy considers that the best estimate has been provided for **Average Unit Cost for Major and Minor Light Installation and Replacement** but concerns are held as we are unable to accurately verify the number of light installations as opposed to the number of jobs against what is believed to be representative of a true figure. This estimate has used the best available data and that is being reviewed and could change in the future once we better understand factors such as whether some are multiple light installations in a single job, or whether costs are being represented elsewhere in other Activity Codes. The Average unit price for lamps, luminaires, brackets and poles is then entered against the average weighted volume of materials for the average Material Price for each item. The average Material Price is multiplied by the average ratio of Material Costs against Direct Costs sourced from the General Ledger over the 2008/09 – 2012/13 period. Assumptions made for this data includes: ▪ Streetlights have been based on Lamp volume as the primary value for calculation of Number of Streetlights and the basis for weighted average volume between the asset categories. ▪ Only Lamps, Luminaires, poles and brackets have been included in the material cost. Other materials have been excluded due to the difficulty in extracting base information to be included in the estimate. These four categories are the main components in Streetlight installation. ▪ Data that was missing for luminaire or lamp average cost utilised replacement data which was sourced from the closest similar inventory item. ▪ Missing average costs for poles and brackets were substituted from the previous year data to ensure consistency of Pole and bracket averages. Missing data would have been due to that stock item not being purchased in that period. ▪ Bracket volume split between Installation and Replacement was based on the average split of poles between the two categories. **Average Unit Cost for Major and Minor Light Maintenance for 2008/09 – 2012/13** The Total of Light Maintenance expenditure from Table 4.1.2 was divided by the total of Light Maintenance Major and Minor Lights in

Minimum Requirements	Ergon Energy Response
	Table 4.1.2 for each financial period to determine an overall average. Workings for these values is provided in the Basis of Preparation for Table 4.1.2. The Average unit cost was unable to be broken down further to Major / Minor light subcategories or to the lower level of Light Type as the material cost is recorded against a separate Activity Code which includes material volumes for other activities. The Bulk Lamp Replacement and Road Patrol programs record the overall volume for the programs at a Major / Minor Light Type level but expenditure is only recorded at an overall project value. Ergon Energy considers that the best estimate has been provided for the above values as the reporting systems are unable to expand to further granular levels without a decline in integrity of estimates methodology used. Introduction of Field Force Automation and the finalisation of audited Streetlight data is expected to improve the quality and depth of data to align with CA RIN requirements.

Category Analysis RIN Basis of Preparation

Template 4.2 Metering

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 4.2 Metering of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 4.2 Metering (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 4.2 Metering, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirement/s were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 4.2 Metering (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 4.2 Metering

Table 4.2.1 - Metering Descriptor Metric (Volumes)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. Ergon Energy notes that it does not have regulated metering services relating to meter categories Type 4 and Type 5. Type 5 metering is not permitted in Queensland as per the National Metrology Procedures Part A. Ergon Energy has identified this in the basis of preparation. Accordingly, metrics have been populated as 'zeroes' in this regard.
	Ergon Energy has prepared the information provided in Template 4.2, Table 4.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. As confirmed by the AER, Ergon Energy has not had regard to paragraph 16.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN. Ergon Energy has not distinguished Metering services between Standard and Alternative Control Services when completing Template 4.2, Table 4.2.1. Data has not been reported in relation to metering services which have been classified as contestable. Non-contestable, regulated metering services have been reported by Ergon Energy including work performed by third parties on behalf of Ergon Energy.
Use of Actual Information	Ergon Energy has been unable to provide Actual Information, in accordance with the AER's definition for Table 4.2.1 for the period 2008/09 to 2012/13
Source of Actual Information	Ergon Energy has been unable to provide Actual Information, in accordance with the AER's definition for Table 4.2.1 for the period 2008/09 to 2012/13
Methodology and assumption's used in relation to Actual Information	Ergon Energy has been unable to provide Actual Information, in accordance with the AER's definition for Table 4.2.1 for the period 2008/09 to 2012/13
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to variables in Table 4.2.1 for all categories associated with Meter Type 6 for the period 2008/09 to 2012/13.
Why is it not possible to use Actual Information, and	It was not possible to use Actual Information, and an estimate is required in relation to Meter Type 6 volumes as available historical

Minimum Requirements	Ergon Energy Response
why an estimate is required	asset information records were unable to provide an accurate differentiation between the asset subcategories. Also, available data extracts did not correlate with the financial year periods required for reporting as reporting has previously occurred on an ad hoc basis. An estimate was used with the closest available actual information (to the corresponding financial year) in Ergon Energy's asset management systems.
How the estimate has been produced	In relation to **Single Phase Meter population and Multiphase Meter population,** Ergon Energy has developed an estimate based on the following approach: Total regulated meters: ▪ The total number of all regulated and non-regulated meters was taken as the Unique count of NMI's and Meter Numbers from the Meter/Tariff Table in the Microsoft Access Data adhoc extracts from the FACOM (Customer Information System) in the months of June 2009, May 2010, August 2011, June 2012 and July 2013. ▪ Non-regulated and contestable meters were identified on the basis of the count of "Large (>100MWH pa) NMI sites who were not EEQ customers and excluded NMI sites that are with EEQ and charged MDA/MDP charges. ▪ Non-regulated and contestable meters for Large NMI customers were subtracted from the total number of all meters, leaving the total number of regulated meters. (Note: This includes meters at "Small" NMI customer Sites where Ergon is RP and MPB) Within this estimated data it is possible to identify the number of multiphase and single phase meters. Multiphase meters were derived from the addition of two types of multiphase meters and is inclusive of CT Meters: ▪ Pre 2001 - Multiphase meters in service prior to 2001 was taken as the number of three phase meters prior to 2001 from the Aged Asset Profile data records presented in the 2012 and 2013 Annual AER RIN data. (Ie The estimated count of multiphase meters from the profiles for Years prior to 2001). The count of multiphase meters for 2009, 2010 and 2011 was estimated by adding 1% pa to the previous year using the 2012 count as the starting point. The number of multiphase meters pre 2001 will decline each year due to failures, tariff upgrades and other purposes (demolition, contestability etc.). Based on service orders raised to maintain meters a failure rate of 0.7% is estimated, so a 1% decline in meters in subsequent years allows for a 0.3% for other causes. This assumption is considered conservative as the reduction between 2012 and 2013 is around 3%, ▪ Post 2001 – a unique property number system was introduced

Minimum Requirements	Ergon Energy Response
	Ergon Energy wide in March 2001 for all multiphase meters that allows these to be readily identified by their property identifier format. A total count of meters purchased with numbers like "9xxxxxxx" is taken from the same Microsoft Access Data ad hoc FACOM extracts from 2001 to the months of June 2009, May 2010, August 2011, June 2012 and July 2013. Single phase meter volumes were calculated by subtracting the total of multiphase meters from the total of regulated meters. Ergon Energy considers that the best estimate has been provided on the basis that: ▪ Ergon Energy have used actual data taken from our Customer Information System as close to annual alignments as was available. ▪ Some variations will exist due to customer transfers and daily customer additions and removals. ▪ Pre 2001 three (3) phase meter counts are estimated from manually extracted asset records based on historical records. In relation to **Current Transformer Meter population and Direct Connect Meter population:** Ergon Energy has developed an estimate based on the following approach: ▪ The Current Transformer meter estimate is a portion of the total three phase meter population. This is based on the current count (2.5.2014) of CT Meters in the Ellipse asset register with an applied Maintenance Schedule Task (MST). All CT Meters have MSTs and are maintained on a periodic basis in accordance with National Electricity Rules (NER) Chapter 7. ▪ The list of NMIs with MSTs (CT Meters) was imported and linked to the same ad hoc Microsoft access FACOM data base extracts to query how many existed with Retailer = Ergon Energy Qld (EEQ) in each year at the months of June 2009, May 2010, August 2011, June 2012 and July 2013. A quantity of EEQ customers are treated as NON-regulated and these were subtracted to obtain the total regulated CT Meter count for each year. The CT Meter count is subject to variation year to year due to influence of the contestable market. The Direct Connected meter population was calculated by subtracting the total Current Transformer meters from the total regulated Single Phase and Multiphase meter counts. Ergon Energy considers that the best estimate has been provided on the basis that: ▪ CT meter estimates are based on actual data taken from FACOM and Ellipse data. ▪ The current list of NMIs with CT meters (those with MSTs) is compared to the list of NMIs in each year, that have Retailer = EEQ to derive a count of CT meters for each year.

Minimum Requirements	Ergon Energy Response
	▪ This count is decreased by the number of NON-regulated EEQ customers in each year to derive the count of regulated CT Meters.

Table 4.2.2 - Cost Metrics (Expenditure and Volumes)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. Ergon Energy notes that it does not have regulated metering services relating to meter categories Type 4 and Type 5. Type 5 metering is not permitted in Queensland as per the National Metrology Procedure Part A. Ergon Energy has identified this in the basis of preparation. Accordingly, metrics have been populated as 'zeroes' in this regard.
	Ergon Energy has prepared the information provided in Template 4.2 - Metering, Table 4.2.2 - Cost Metrics in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Ergon Energy has not distinguished between expenditure for Metering services between Standard and Alternative Control Services when completing Template 4.2, Table 4.2.1. Furthermore, expenditure has not been distinguished between capex and opex. This was further clarified by the AER in its issues register, where it noted that all items of capex and opex that were necessary to provide the services listed in templates 4.1 to 4.4 were to be included. In this regard, costs have been measured as the direct cost, excluding overheads. Data has not been reported in relation to metering services which have been classified as contestable. Non-contestable, regulated metering services have been reported by Ergon Energy including work performed by third parties on behalf of Ergon Energy. Finally, consistent with guidance provided by the AER in its issues register in relation to certain meter services costs, Ergon Energy notes that: ▪ meter data costs that could be attributable to specific meter reading activities has been reported as part of the cost for the relevant meter reading services category; and ▪ data processing costs which could not be attributable to a specific activity has been reported in the "other costs (metering)" category.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's definition, for the following variables in Table 4.2.2 - Cost Metrics

Minimum Requirements	Ergon Energy Response
	(volumes): ▪ Meter Purchases for the period 2008/09 – 2012/13 ▪ Meter Testing for the period 2008/09 – 2012/13 ▪ Meter Investigation for the period 2008/09 – 2012/13 ▪ Scheduled Meter Reading for the period 2008/09 – 2012/13 ▪ Special Meter Reading for the period 2008/09 – 2012/13 ▪ New Meter Installation for the period 2011/12 – 2012/13 ▪ Meter Replacements for the period 2008/09 – 2009/10 ▪ Meter Maintenance for the period 2008/09 – 2011/12 Ergon Energy has used Actual Information, in accordance with the AER's definition, for the following variables in Table 4.2.2 - Cost Metrics (expenditure): ▪ Meter Purchases for the period 2008/09 – 2012/13 ▪ Meter Testing for the period 2008/09 – 2012/13 ▪ Meter Investigation for the period 2009/10 – 2012/13 ▪ Special Meter Reading for the period 2009/10 – 2012/13 ▪ Meter Replacements for the period 2008/09 – 2009/10 ▪ Meter Maintenance for the period 2008/09 – 2012/13
Source of Actual Information	Sources of Actual Information for the following variables, are noted below: ▪ **Meter Purchases volumes** were sourced from Supplier Performance reports based on Ellipse data and Billing Records of Non-Regulated and Non Contestable Meters to Retailers. ▪ **Meter Purchases expenditure** was sourced from Supplier Performance reports based on Ellipse data and Billing Records of Non-Regulated and Non Contestable Meters to Retailers. ▪ **Meter Testing volumes** were sourced from Ellipse reports based on Activity Codes and historical in-situ testing project reporting. ▪ **Meter Testing expenditure** was sourced from Ellipse reports based on Activity Code. ▪ **Meter Investigation volumes** were sourced from MOS Service Standards reports based on Citrix data. ▪ **Meter Investigation expenditure** was sourced from Ellipse reports based on Activity Code and Standard Job numbers ▪ **Scheduled Meter Reading volumes** were sourced from Operational reports based on FACOM data referencing existing and historical annual meter reading reports and excludes self reads,

Minimum Requirements	Ergon Energy Response
	annual reads or depot reads for scheduled reading purposes. ▪ **Special Meter Reading volumes** were sourced from MOS Service Standards reports based on Citrix data. ▪ **Special Meter Reading expenditure** was sourced from Ellipse Reports for Standard Jobs relating to Special Reads. ▪ **New Meter Installations volumes** were sourced from annual Meter Changes Reports based on FACOM data. ▪ **Meter Replacement volumes** were sourced from Project Reporting for the Meter Replacement Projects. ▪ **Meter Replacement expenditure** was sourced from Ellipse Reports for Meter Replacement Contract code 2008/6118/T. ▪ **Meter Maintenance volumes** were sourced from MOS Service Standards reports based on Citrix data. ▪ **Meter Maintenance expenditure** was sourced from Ellipse Reports for Activity Code 53120 Corrective Regulated Meters.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to take the following approach: ▪ **Meter Purchase volumes and expenditure** - was summarised from the Supplier Performance reports. Meters supplied are not distinguished from non-regulated or contestable meters until they are booked from stores and have therefore not been removed (which would represent less than 1% of volume). Spare part meter costs were included for the MK3 meter with no other charges as the remaining meter types are scrapped and refurbished by an external party who would incur any of these costs. A RITI (Receive Inspect Test Issue) process was not utilised during this period and no testing of equipment costs are involved for testing of meters during the purchasing process. ▪ **Meter Testing expenditure** was extracted from Ellipse Reports using Activity Code 52130 Preventive Maintenance Regulated Meters with cross referencing to the Standard Job for Meter Test (MMP010- LV Revenue Metering 10 Yearly Site Maintenance, MMP050 - LV Revenue Metering 5 Yearly Site Maintenance), Maintenance Type MP. Costs associated with Business Overheads were removed. The In-situ testing work order costs were also included from Activity Code 53130 with overheads removed. ▪ **Meter Testing volume** data was developed on the assumption that each work order raised from the above cross reference was equivalent to one Meter Test. In Situ meter testing volumes (from Activity Code 53130) were also added to the relevant year. ▪ **Meter Investigation expenditure** are summarised from Ellipse reports cross referencing expenditure from Activity 56000 (Customer Installation Services) and 56050 (Revenue Protection Services) and filtered for the Standard metering job types – "10/1

Minimum Requirements	Ergon Energy Response

	Meter Query" and "Type 18 Revenue Protection". **Volumes** are the total number of Service orders raised for job types "10/1 Meter Query" and "Type 18 Revenue Protection". In doing so, it was assumed that a service order was counted as one meter investigation.
	▪ **Scheduled Meter Reading Volumes** are summarised from monthly MVRS reports with 12 months rolling data. This is data sourced from FACOM and MVRS and consolidated into the end of month operational reports.
	▪ **Special Meter Reading expenditure** was extracted from Ellipse Reports using Activity Code 56200 Alternative Control Services and 56020 Mass Market Meter Reads with cross referencing to the below Standard Jobs:
	  ▪ 711 Special Reads
	  ▪ 811 Check Read – Cust Requested
	  ▪ 821 Check Read - Ergon Requested Reading
	  ▪ 831 Check Read - Major/Demand Requested Reading
	  ▪ 841 Check Read - Billing Estimated Reading
	  ▪ 861 Check Read - EEQ Requested Reading
	▪ **Special Meter Reading Volumes** are summarised from MOS Service Standards reports extracting the total number of Special Reads and Check Read related to the list above for each year which correspond to the Standard Jobs above.
	▪ **New Meter Installations** volumes are the total number of Service orders raised for service order types "Initial Connections" (sourced from MOS Service Standards which utilises FACOM data). An assumption is made that the data request is only for Initial Connection numbers and not for inclusion of meters installed as a replacement or upgrade for other customer or business requests.
	▪ **Meter Maintenance expenditure** are extracted from Ellipse Reports using Activity Code 53130 Corrective Maintenance Reg Meters with expenditure for Non-Revenue meter maintenance i.e. High Voltage and statistical metering, in-situ testing and communication costs removed.
	▪ **Meter Maintenance volumes** are extracted from MOS Service Standards reports totalling the total number of Meter Maintenance Service Orders raised for Complex (Type 11.4) and Non-complex meters (Type 10.3).

Use of Estimated Information	Ergon Energy has used Estimated Information in relation to the following variables the following variables in Table 4.2.2 - Cost Metrics (volumes): ▪ Meter Maintenance for 2012/13 Ergon Energy has used Estimated Information in relation to the

Minimum Requirements	Ergon Energy Response
	following variables the following variables in Table 4.2.2 - Cost Metrics (expenditure): ▪ Meter Investigation for 2008/09 ▪ Scheduled Meter Reading for the period 2008/09 – 2012/13 ▪ Special Meter Reading for 2008/09 ▪ New Meter Installation for the period 2008/09 – 2012/13 ▪ Other Metering Meter Type 6 for the period 2008/09 – 2012/13
Why is it not possible to use Actual Information, and why an estimate is required	Reasons as to why it was not possible to provide Actual Information, and why an estimate is required in relation to each of the variables is noted below: ▪ **Scheduled Meter Reading** expenditure for processing, storage and delivery of metering data and the management of relevant NMI Standing Data is not recorded under the Mass Market Reading Activity Code. Actual information for the collection of Meter Data has been reported on and collated and described in the section below. ▪ **New Meter Installation** expenditure as New Meter costs and New Services costs are bundled together and are not able to be accurately separated to report on the two categories separately. ▪ **Meter Investigation and Special Meter Reading** for 2008/09 as costs reported from Ellipse could not be validated and justified against the volumes of work in the relevant service subcategory for that period. ▪ **Other Metering Meter Type 6** expenditure is recorded under general Activity Codes and best measures are made to ensure that Other Metering Activities are recorded from the below methodology but not all activities may have been captured. ▪ **Other Metering Meter Type 7** expenditure is reported as zero values as all regulated expenditure has been reported under the Public Lighting CA RIN category. Watchman lights and other unmetered supplies have no reportable value. ▪ **Meter Maintenance volumes** for 2012/13 as totals reported from the MOS Service Standards could not be validated and justified against the expenditure for that period.
How the estimate has been produced	**Scheduled Meter Reading** In relation to Scheduled Meter Reading Ergon Energy has developed estimates based on the following approach: ▪ Actual Information for **Scheduled Meter Reading expenditure** was sourced from Ellipse Reports for Activity Code 56020 Mass Market Meter Reading which represents the collection of data cost. Special Reads had expenditure under this Activity Code which was subtracted from this total.

Minimum Requirements	Ergon Energy Response
	▪ Estimates were then used for calculating the additional cost of processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the Rules. In developing this estimate for these additional costs, Ergon Energy has made the following assumptions: ▪ 16 staff are required on a full-time basis for processing of regulated data (based on an estimate from the MDP manager). These staff costs have been calculated at an average of the stated pay grade over the five years ▪ Licencing costs for software licencing, data warehousing and process systems costs were proportioned between the estimated usage between regulated and non-regulated meter data purposes by best estimates of the Meter Data Manager. ▪ Ergon Energy considers the best estimate has been provided for Scheduled Meter Reading on the basis that system and resource costs are not allocated between regulated and non-regulated activities and cost estimates and the associated methodology for deriving these estimates were verified by relevant Subject Matter Experts. **New Meter Installation expenditure** In relation to New Meter Installation expenditure, Ergon Energy has developed an estimate based on the following approach: ▪ Step 1: All Costs for last 7 Years for New Meters was extracted from Ellipse. ▪ Step 2: A filter was applied to “J3 Code - D Meters – New” and total Costs for “New Meters” Projects 2007 to 2013 by expenditure category : Labour, Materials and Other derived as a % of Total (exc. Overheads) (I.e. Ratio 17 : 80 : 3 %) ▪ Step 3: The total costs was divided by 7 to get an average annual cost for “New Meters”. ▪ Step 4: Next an estimate of the total number of meters installed per annum was derived from the average number of meters installed on all 11/12 & 12/13 Service Order types. This was used to build an estimate of the total Meter Materials cost per annum, (including Receivers, Current Transformers and incidental meter material components). The total materials cost was divided by the number of meters to obtain an average per unit cost for meters per installation. The % of Labour, Materials and Other costs for “New Meters” was used to derive the per unit cost for each cost component. ▪ Step 5: Labour was estimated at 1 hour of a Technical Service Person at the 2012/13 rate (source Ellipse – ESS module) and added to the New Meters total for an average per unit cost.

Minimum Requirements	Ergon Energy Response
	▪ Step 6: The average per unit cost for Labour Materials and Other including installation from Step 7 is applied to the total Number of Service Orders for new installation Service orders in each year to derive the total cost of "New Meter Installations". In developing this estimate, Ergon Energy has made the following assumptions: ▪ The costs for "New Meters" is calculated over 7 Years was used as Project Completion dates could not be determined to allocate costs to a particular year and a Large portion of costs defaulted to 2007.) ▪ . An allowance of an average of 1 hour labour has been allocated.. This assumption is based on advice from Subject Matter Experts involved in the provision of new services and the meter installation process. ▪ These two figures are totalled and multiplied against the number of New Meter Installation values to determine total expenditure. ▪ An assumption is made that the data request is only for Initial Connection numbers and not for inclusion of meters installed as a replacement or upgrade for other customer or business requests. ▪ As advised by the AER, CAPEX costs have been included. Ergon Energy considers the best estimate has been provided for New Meter Installation expenditure on the basis that: ▪ No exact figure is available; ▪ Cost estimates are based on Ellipse and FACOM data; ▪ Average expenditure is expected to provide a good approximation of actual costs; ▪ The assumptions and methodology underpinning the estimated cost data have been verified by Subject Matter Experts using the Steps outlined above; and ▪ Best endeavours have been used to extract values from existing data. **Meter Investigation and Special Meter Reading expenditure** In relation to Meter Investigation and Special Meter expenditure for 2008/09, Ergon Energy has developed an estimate based on the following approach: ▪ The average expenditure of the relevant service subcategory is determined for the 2009/10 to 2012/13 Financial periods ▪ This average is multiplied against the volume of the relevant service subcategory to provide substituted data. Ergon Energy considers the best estimate has been provided for on the basis that average expenditure during the 2009/10 to 2012/13 period is expected to provide a reasonably proxy for average expenditure during 2008/09.

Minimum Requirements	Ergon Energy Response
	Meter Maintenance volumes In relation to Meter Maintenance volumes for 2012/13, Ergon Energy has developed an estimate based on the following approach: ▪ The average cost of a meter maintenance service is determined for the 2008/09 to 2011/12 Financial periods; ▪ Total Meter Maintenance expenditure for 2012/13 is divided by the above average to determine an estimate of the number of meter maintenance services provided during the year. Ergon Energy considers the best estimate has been provided for on the basis that: ▪ the average cost of a meter maintenance service during the 2008/09 to 2011/12 period is expected to provide a reasonable proxy of the cost of a meter maintenance service in 2012/13; and ▪ Actual total meter maintenance expenditure for 2012/13 is sourced from financial data. **Other Metering Meter Type 6 expenditure** In relation to Other Metering Meter Type 6 expenditure, Ergon Energy determined an estimate based on the following approach: ▪ Other Metering Type 6 expenditure consists of the totalling of the following subtotals: o Other Metering Type 6 Opex o Other Metering Type 6 Capex o Other Metering Type 6 ACS charges Other Metering Type 6 Opex subtotal was calculated by summing the total expenditure that had been previously reported in the other subcategories by Activity Codes that is listed in the Metering General Ledger Extract. These were: ▪ 52130 Preventive Regulated Meters ▪ 53130 Corrective Regulated Meters ▪ 56010 Network Metering ▪ 56020 Meter Reading Mass Market ▪ 56050 Revenue Protection Services/Meter Tamper This total was subtracted from the General Ledger Opex total for each financial year. Metering expenditure in Corrective and Preventative Maintenance which had previously been identified as non reportable either due to being for non-regulated, HV or Statistical metering was also subtracted to give the Other Type 6 Opex total. Other Metering Type 6 Capex subtotal was calculated by subtracting the total of CAPEX expenditure (New Meter Installation and Meter Replacement) from the General Ledger Capex total.

Minimum Requirements	Ergon Energy Response
	Other Metering Type 6 ACS subtotal was calculated by accumulating the total of other Metering Activities which had not been identified in the previous subcategories. These were: ▪ 10.13 Maintain Meter - Miscellaneous ▪ 10.3 Maintain Meter - Maintain Meters ▪ 11.4 Complex Meter - Meter services - Meter/Tariff/Query ▪ 2.1 Alts and or Adds - Metering ▪ 2.3 Alts and or Adds - Remove Meter ▪ 2.4 Alts and or Adds - Move Meter ▪ 2.5 Alts and or Adds - Meter Replacement ▪ 2.6 Alts and or Adds - Remove Load Control ▪ 2.8 Alts and or Adds - Solar - Metering An Ellipse report was run to extract the direct cost of these Work orders completed each year using Q Codes. From this it was identifiable that there were two primary Activity Codes that made up 98% of the expenditure – 56000 Customer Installation Services and 56200 – ACS General. It was decided to only use these Activity Codes due to their relevance to Alternative Control Services Metering Activities. The total of all Q Codes was summarised for each financial period to provide the Other Type 6 ACS charge. In developing this estimate, Ergon Energy has made the following assumptions: ▪ ACS costs from the General Ledger were not considered as they were sourced from Product Codes. It is suspected that not all ACS costs involved for regulated metering have the corresponding Product Codes. As an alternative it was decided to work from Activity Code for a more accurate outcome. **Load Control and Receivers expenditure is included in the Other Metering Type 6 expenditure category**. Ergon Energy considers that the best estimate has been provided on the basis that the expenditure will represent the majority of Metering activity costs that have not been reported in the other subcategories. **Other Metering Meter Type 7 expenditure** In relation to Other Metering Meter Type 7 for 2008/09 – 2012/13, expenditure is reported as zero value as all regulated expenditure has been reported under the Public Lighting CA RIN category. Watchman lights and other unmetered supplies have no reportable value.

Category Analysis RIN Basis of Preparation

Template 4.3 Fee Based ACS

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 4.3 Fee Based ACS of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 4.3 Fee Based ACS (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 4.3 Fee Based ACS, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 4.3 Fee Based ACS (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 4.3 Fee Based ACS

Table 4.3.1 - Cost Metrics for Fee Based Services (Expenditures and Volumes)

Table 1: Addressing Minimum BOP Requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 4.3, Table 4.3.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. As advised by the AER, Ergon Energy has not had regard to paragraph 15.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN. For the purposes of completing Template 2.7, Ergon Energy has reported categories for fee-based services that were listed in its Annual Pricing Proposal encompassing each relevant year taking note of Appendix E, Principles and Requirements, paragraph 15.2 of the AER's Notice. However, there are instances where the Pricing Proposal category headings differ slightly to the mandatory categories in the template therefore the following mapping has been applied: **CA RIN Mandatory Category** — **EECL Pricing Proposal** De-energisation — De-energisation during business hours Re-energisation — Re-energisation during business hours Although Wasted Truck Visit was reported in the Pricing Proposal at the aggregated level in the initial years (2009, 2010), it was later disaggregated between one and two person crew. As such, reporting for this service has been displayed over two line items, reporting in this manner also provides consistency for comparability across years Also relative to requirement 15.2 only fee-based services have been populated in this template. The mandatory category, 'energisation' is a Connection Service classified as a Standard Control Service (not a fee-based or quoted service), therefore has been excluded. Only operating costs have been reported, no capex is captured for fee based services. Furthermore, in meeting requirements of Appendix E, Principles and Requirements paragraph 15.3 of the AER's Notice, **Table 2** (following) provides a description of each fee based service listed in regulatory template 4.3 including the purpose of each service and the activities which comprise each service. Costs have been measured as the direct cost, excluding overheads.
Use of Actual Information	Ergon Energy has used Actual Information, in accordance with the AER's

Minimum Requirements	Ergon Energy Response
	definition, for all variables in Table 4.3.1 for the period 2008/09 to 2012/13
Source of Actual Information	Actual Information for the variables was sourced from a combination of Ellipse, MERs Financial Reporting and FACOM.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to combine the total count of services from the two source systems being Ellipse and FACOM for the product codes applicable to fee based services for the required years. Fully absorbed expenditure has been extracted from prior Annual Performance RINs. The overheads included in these fully absorbed costs were identified in the 2012/13 Ellipse General Ledger for each relevant product codes and then these overhead costs were removed from the previously reported numbers to produce the required direct costs. The proportion of the fully absorbed costs that relates to overheads as identified for 2012/13 was removed from each of the prior years to produce the reported direct costs. Due to the extraction of volumes and values from disparate systems, some results are showing volumes without costs (or vise versa). These services are immaterial in nature. Reporting for wasted truck visits in the Pricing Proposal in initial years (2009, 2010) was on an aggregated basis for a one or two person crew. Therefore, both services need to be reviewed in aggregate when assessing comparability of results.
Use of Estimated Information	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
How the estimate has been produced	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.

Table 2: Fee Based Services

The Fee Based Services in the below table are reflective of all of the categories of Fee Based Services that were listed in Ergon Energy's Annual Pricing Proposal of each relevant year in accordance with Appendix E, Principles and Requirements, paragraph 15.2 of the AER's Notice.

Common and Miscellaneous Services	Purpose / Activities of each service
Subdivision Fees	Fees associated with assessing a customer's application requesting a connection be made between the Ergon Energy network and a subdivision. Includes subdivision works carried out by contractors and/or Ergon Energy.
Project Fees	Fees associated with assessing an application requesting a connection to be made (or altered) between the Ergon Energy network and the customer's installation. Applies to small customer connections only (i.e. a customer classified as a Standard Asset Customer (SAC)).
De-energisation	De-energisation commenced during business hours, all instances
Re-energisation	Re-energisation commenced during business hours, not "after de-energisation for debt"
Re-test at customer's installation during business hours	Customer has submitted Form A and the Retailer has issued a Service Order Request, but installation fails test and cannot be connected, requiring a re-test of the installation - business hours
Supply Abolishment during business hours	Decommissioning of a NMI and associated metering. May be used where a property is to be demolished; supply is no longer required; an alternative connection point is to be used; or a redundant supply is to be removed
Temporary Builders Supply, not in permanent position- single phase metered – business hours	Connection of a single phase supply to a meter location that is not permanent.
Temporary Builders Supply not in permanent position - multi phase metered – business hours	Connection of a multi-phase supply to a meter location that is not permanent
Restoration of supply required due to customer action, during business hours	For example: service fuse replacement or restoration of loss of supply caused by the customer's installation - business hours

Common and Miscellaneous Services	Purpose / Activities of each service
Wasted truck visit - one person crew	Service is not able to be completed after truck has left the depot. Includes: Retailer/customer cancels service order after truck has left the depot but before service order is completed; Crew is unable to access site to perform service order; or Customer has submitted Form A and the Retailer a Service Order Request, but the installation is not ready on arrival at site.
Wasted truck visit – two person crew	Service is not able to be completed after truck has left the depot. Includes: Retailer/customer cancels service order after truck has left the depot but before service order is completed; Crew is unable to access site to perform service order; or Customer has submitted Form A and the Retailer a Service Order Request, but the installation is not ready on arrival at site.
Wasted truck visit	Service is not able to be completed after truck has left the depot. Includes: Retailer/customer cancels service order after truck has left the depot but before service order is completed; Crew is unable to access site to perform service order; or Customer has submitted Form A and the Retailer a Service Order Request, but the installation is not ready on arrival at site.

Category Analysis RIN Basis of Preparation

Template 4.4 Quoted ACS

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 4.4 Quoted ACS of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 4.4 Quoted ACS (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 4.4 Quoted ACS, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provide additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 4.4 Quoted ACS (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 4.4 Quoted Services ACS

Table 4.4.1 - Cost Metrics for Quoted Services (Expenditures and Volumes)

Table 1: Addressing Minimum BOP Requirements

<table>
<tr><th>Minimum Requirements</th><th>Ergon Energy Response</th></tr>
<tr><td rowspan="2">Consistency with the requirements of the Notice</td><td>Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.</td></tr>
<tr><td>
Ergon Energy has prepared the information provided in Template 4.4, Table 4.4.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
As advised by the AER, Ergon Energy has not had regard to paragraph 15.1 of the AER’s Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN.
For the purposes of completing Template 2.7, Ergon Energy has reported categories of Quoted Services that were listed in its Annual Pricing Proposal of each relevant year taking note of Appendix E, Principles and Requirements, paragraph 15.2 of the AER’s Notice.
In the earlier years (2009, 2010) there were some instances where services were disaggregated in the Pricing Proposal at a lower level than the costs were captured in Ellipse. Therefore, these services have been reported at the aggregated level where the nature and purpose of the service is the same. As the later years (2011 – 2013) were presented in the Pricing Proposal at the aggregate level, reporting in this manner also provides consistency for comparability across years. The services relate to:
<table>
<tr><th>Service Description
(Aggregated)</th><th>Service Description
(Disaggregated in Pricing Proposal)</th></tr>
<tr><td>Provision of service during business / after-hours requiring one/two person crew</td><td> Provision of service during business hours requiring one person crew; Provision of service during business hours requiring two person crew; Provision of service after hours, requiring one person crew; Provision of service after hours, requiring two person crew. </td></tr>
<tr><td>Temporary De-energisation single visit during business hours – no dismantling</td><td> LV Service Line Drop and Replace in Single Visit during Business Hours - Physical Dismantling; HV Service line drop and replace in single visit during business hours; HV Service line drop and replace in single visit after hours; LV Service line drop and replace two visits </td></tr>
</table>
</td></tr>
</table>

Minimum Requirements	Ergon Energy Response
	<table><tr><td></td><td>during business hours (same day) - physical dismantling; LV Service line drop and replace two visits after hours (same day) - physical dismantling; Temporary de-energisation two visits during business hours (same day)- no dismantling.</td></tr><tr><td>**Special meter read**</td><td>Meter check read Special meter read</td></tr></table> Furthermore, reporting of Other Recoverable Works in the earlier years (2009, 2010) was later (2011 – 2013) disaggregated into Removal / Relocation of Ergon Energy assets at customer request and emergency recoverable works. In meeting requirements of Appendix E, Principles and Requirements paragraph 15.3 of the AER's Notice, **Table 2** below provides a description of each Quoted Service listed in regulatory template 4.4 including the purpose of each service and the activities which comprise each service In completing the template, all services reported are classified as an Alternative Control Services (previously Excluded Distribution Service), no Standard Control Services have been reported. Similarly, although Ergon Energy is not required to distinguish between capex or opex all costs relate to opex with the exclusion of Large Customer Connections in the 2013 which also include Capex costs. Costs have been measured as the direct cost, excluding overheads. Furthermore, the AER noted at Issue 58 in the Issues Register that recoverable work projects (including all costs associated with customer requested capital works for which the prime purpose is to satisfy a customer requirement other than new or increased supply) was to be included as quoted services and hence captured in template 4.4. These projects have been excluded from connections works under template 2.5.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for all variables in Table all variables in Table 4.4.1 for the period 2008/09 to 2012/13.
Source of Actual Information	Actual Information for the variables was sourced from Ergon Energy's Ellipse, MERS Financial Reporting and FACOM.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, it was necessary for Ergon Energy to combine the total count of services from the two source systems being Ellipse and FACOM for the product codes applicable to quoted based services for the required years. Fully absorbed expenditure has been extracted from prior Annual Performance RINs. The overheads included in these fully absorbed costs were identified in the 2012/13 Ellipse General Ledger for each relevant product codes and then these overhead costs were removed from the

Minimum Requirements	Ergon Energy Response
	previously reported numbers to produce the required direct costs. The proportion of the fully absorbed costs that relates to overheads as identified for 2012/13 was removed from each of the prior years to produce the reported direct costs. As noted above the service 'Other Recoverable Works' was re-classified into the following two services from FY 2011 onwards: ▪ Removal / Relocation of Ergon Energy Assets at Customer request and; ▪ Emergency Recoverable Works Reporting of the following service, 'Provision of service during business/ after-hours requiring one/two person crew' in Pricing Proposals relevant to 2011 to 2013 years was consolidated as once service. In prior years, these four services were reported separately. Due to the extraction of volumes and values from disparate systems, some results are showing volumes without costs (or vice versa). Most services are immaterial in nature with the exception of emergency recoverable works. In this instance, the following three services should be assessed together in aggregate Other Recoverable Works, Removal / Relocation of Ergon Energy assets at customer request, and emergency recoverable works.
Use of Estimated Information	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
How the estimate has been produced	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.

Table 2: Ergon Energy Quoted Services

The Quoted Services in the below table are reflective of all of the categories of Quoted Services that were listed in Ergon Energy's Annual Pricing Proposal of each relevant year in accordance with Appendix E, Principles and Requirements, paragraph 15.2 of the AER's Notice.

Quoted Services	Purpose and Activities of Service
Removal/Relocation of Ergon Energy assets at customer request	Removal, relocation or rearrangement of assets at customer request, that would not otherwise have been required for the efficient management of the network, or covered by another service.
Other recoverable works	Removal, relocation or rearrangement of assets at customer request, that would not otherwise have been required for the efficient management of the network, or covered by another service.
Large Customer Connections	Negotiated network design and construction contracts which require design and construction of connection assets for major network customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or an Embedded Generator (EG).
Emergency Recoverable Works	Work carried out as a result of an emergency or third party action, that would not otherwise have been required for the efficient management of the network, or covered by another service. For example: repair of assets due to vehicle accident.
Move point of attachment during business hours - single/multi phase	De-energisation, followed by physical dismantling then reattachment of service and re-energisation. Typically one hour or less on site.
Relocation of point of attachment of service (single visit) - single/multi phase during business hours	De-energisation, followed by physical dismantling then reattachment of service and re-energisation. Typically one hour or less on site.
Tiger tails	Installation of covers on service lines
Provision of historical metering data	Request for historical metering data prior to the previous 2 years, on request.
Provision of metering data above minimum requirements	For example: urgent delivery, summarisation of metering data etc
Meter test	Meter test by EECL for EECL whole current type 5-7 meters only. Only available where meter installed and operational.
Change Tariff	Change to tariff, that requires meter reprogramming (except for controlled load timing changes)

Quoted Services	Purpose and Activities of Service
Change Time Switch	Change to time switch setting
Removal of a meter	Remove meter and re-commission installation on request; no re-wiring required
Removal of load control device	Remove load control relay or time clock on request
Special meter read	Off-cycle meter read, during business hours
Reprogram Card Meters	Attend and reprogram card meters to reflect retail tariffs, outside scheduled visit
Exchange Meter (Type 5-7)	Like for like meter exchange on request, unless not allowed by regulation.
Move the meter (Type 5-7)	Relocate meter from current position and re-commission installation on request; no change of service point
Provision of Connection Services above minimum requirements	Customer requested increase in reliability or quality of supply beyond the standard
Higher reliability or quality of supply	Customer requested increase in reliability or quality of supply beyond the standard
Overhead service upgrade - no change to load	For example change from single phase to multi phase and/or increase capacity
Underground service upgrade	For example change from single phase to multi phase and/or increase capacity
Provision, installation and maintenance of meters above minimum requirements	Provision of meters above the minimum regulatory requirements on request
Prepayment Meters at Customer Request	Installation of pre-payment meters on request - see Notified Prices for conditions.
Temporary De-energisation single visit during business hours - no dismantling	Temporary de-energisation and re-energisation of supply at the service fuse to allow customer or contractor to work close - no dismantling of service required (i.e. no service line drop). Typically 1 hour or less on site
De-energisation after hours	De-energisation commenced after business hours, all instances
Re-energisation after hours	Re-energisation commenced after business hours, all instances
Restoration of Supply required due to customer action - after hours	For example: service fuse replacement or restoration of loss of supply caused by the customer's installation - after hours

Quoted Services	Purpose and Activities of Service
Subdivision Fees	Other fees associated with services Ergon Energy provides in considering sub-division plans. Includes fees associated with specification and design and the auditing of design and construction.
Project Fees	Other fees associated with services Ergon Energy provides in considering customer initiated projects. Includes application fees for major customer connections, and fees relating to specification and design and the auditing of design and construction.
High Load Escort	Request by customer to disconnect and reconnect to the distribution network and lift wires to allow a high load vehicle through the most appropriate corridor
Rectification of illegal connections	Repair works to re-establish a safe and legal connection
Conversion of aerial bundled cables	Conversion of separate aerial cables to bundled aerial cables.
Provision of service during business/after hours requiring one/two person crew	For example: safety observer, installation inspection, query tariff, revenue protection activity - business hours / after hours. Tree trimming, switching - business / after hours
Provision of service during business hours requiring one person crew	For example: safety observer, installation inspection, query tariff, revenue protection activity - business hours
Provision of service during business hours requiring two person crew	For example: tree trimming, switching - business hours
Provision of service after hours, requiring one person crew	For example: safety observer, installation inspection, query tariff, revenue protection activity - after hours
Provision of service after hours requiring two person crew	For example: tree trimming, switching - after hours
LV Service Line Drop and Replace in Single Visit during Business Hours - Physical Dismantling	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (e.g. Overhead Service dropped). Typically 1 hour or less on site
HV Service line drop and replace in single visit during business hours	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - High Voltage Switching and access is required.

Quoted Services	Purpose and Activities of Service
HV Service line drop and replace in single visit after hours	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - High Voltage Switching and access is required.
LV Service line drop and replace two visits during business hours (same day) - physical dismantling	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (eg Overhead Service dropped).
LV Service line drop and replace two visits after hours (same day) - physical dismantling	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (eg Overhead Service dropped).
Temporary de-energisation two visits during business hours (same day)- no dismantling	Temporary de-energisation and re-energisation of supply at the service fuse to allow customer or contractor to work close - no dismantling of service required (i.e. no service line drop).
Meter check read	Off-cycle meter read, during business hours
Erection of extra poles (only on a customer's installation)	Erection of extra poles (only on a customer's installation)
Relocation of point of attachment of service (two visits)- single/multi phase during business hour	De-energisation, followed by physical dismantling then reattachment of service and re-energisation

Category Analysis RIN Basis of Preparation

Template 5.2 Asset Age Profile

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 5.2 Asset Age Profile of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 5.2 Asset Age Profile (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 5.2 Asset Age Profile, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirement/s were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 5.2 Asset Age Profile (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 5.2 Asset Age Profile

Ergon Energy provides the below comments specific to individual asset groups / categories represented in Template 5.2.

It should be noted that data has been sourced through the efforts of a number of independent subject matter experts. The Category Analysis RIN Code has been applied to both Table 2.2.1 and 5.2.1 has been used to consolidate all data.

Table 5.2.1 - Asset Age Profile

Table 1: Poles

Minimum Requirements	Ergon Energy Response - Poles
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category.
Methodology and assumption’s used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category.

Minimum Requirements	Ergon Energy Response - Poles
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period (1919/20-2012/13) ▪ Age Profile (installed assets, quantity currently in commission by year) ▪ Economic Life (mean and standard deviation)
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** Because it was not possible to provide Actual Information in relation to age profiles date for all asset categories within the Poles Asset Group, all data is declared as estimated and estimation was required for. ▪ Natural poles manufactured pre mid 1960s were not fitted with an identification disc. Furthermore, a large data gap exists for around 20% of poles which have lost or have no disc. ▪ For Wood poles (both not reinforced and reinforced) this involves poles installed from 1964 to the present which is the era when they were known to be used. ▪ For Concrete/Steel Poles, this involves poles installed from 1980 to the present as this is the known era where substantial quantities of concrete and other steel poles were known to have been installed. ▪ For steel streetlight poles, this involves poles installed from 1990 to the present as this is the period of time for which installation of UG cable increased and therefore so too did the installation of streetlights on dedicated poles. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** In relation to Age Profile, Ergon Energy has developed an estimate based on the following approach: In the absence of specific records, Ergon Energy has attempted to infer Year of installation from related or nearby asset data records. In continued absence of reasonable results, Ergon Energy has attempted to infer near-YOM from records about the manufacturing and available records from Manufacturers. In continued absence of reasonable results, Ergon Energy has used more tenuous relationships to determine an age profile as it is understood that an important end purpose of the RIN Template 5.2.1 data is to use it to populate the AER's REPEX model. Similar age inference processes were used during the development of Ergon Energy's internal CBRM modelling. In developing this estimate, Ergon Energy has made the following

Minimum Requirements	Ergon Energy Response - Poles
	assumptions: ▪ That similar nearby assets will have been installed at approximately the same time ▪ For poles that are still unknown that on average the same number of poles are installed (of the same type) each year. Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that: ▪ A hierarchy of logic has been used so that the best possible value for the Age Profile was chosen, including basing the age on surrounding equipment and finally at the lowest level distributing the years across the period that the poles were known to be used. ▪ Ergon Energy uses the Field Mobile Computing (FMC) to provide Pole Maintenance data to the cooperate system. There are delay between the installation date and inspection date. This causes distortion in the age profile of the newly installed pole data. This distortion will be cleared after the maintenance inspection. **ECONOMIC LIFE** Ergon Energy has calculated the Economic life from the CBRM (Condition Based Risk Management) model using the model's "Expected Life" as the economic life and the square root of the expected life as the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as the CBRM takes into consideration the Ergon Energy Subject Matter Expert and EA Technology (Aging Asset Specialist) advice along with condition based information such as location and duty parameters.

Table 2: Pole Staking

Minimum Requirements	Ergon Energy Response – Pole Staking
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset

Minimum Requirements	Ergon Energy Response – Pole Staking
	category.
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period(1919/20-2012/13) Age Profile (installed assets, quantity currently in commission by year) Economic Life (mean and standard deviation).
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** It was not possible to provide Actual Information, and an estimate is required in relation to age profiles date for Pole Staking because Ergon Energy does not treat pole staking as an asset but as an activity. As a maintenance activity the records are initially recorded in Ergon Energy's "Field Mobile Computing" product (FMC). This product has a long history of problematic interfacing with Ellipse, therefore records are reliant on activity based work orders. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** In relation to Age Profile, Ergon Energy has developed an estimate based on the following approach: ▪ Ergon Energy has used Works Order information to obtain age profile back to 2002, beyond this the population was spread between 1985 (date of commencement of pole staking) and 2002. Known duplicates generated during a system conversion in 2004 and 2005 have been manually removed. In developing this estimate, Ergon Energy has made the following assumptions: ▪ There were no staked poles before 1985 ▪ Closed works orders equate to installed pole stakes ▪ Staked poles are NOT counted as a unique asset, they are counted under the poles category, including these in pole counts will lead to counting duplicates and totals will then not equal the totals in table 2.8.1 Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that: ▪ For staking of wooden poles. Work Orders were used to estimate the number of poles back to 2002, earlier results have been manually populated to include the total number of poles

Minimum Requirements	Ergon Energy Response – Pole Staking
	ECONOMIC LIFE In relation to Economic Life and Standard Deviation, Ergon Energy has developed an estimate based on the following approach: ▪ SME best estimate and the square root of the mean as the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as there is no information on the age of staked poles when they are removed, this is Ergon Energy's best estimate.

Table 3: Overhead Conductors and Underground Cables

Minimum Requirements	Ergon Energy Response – Overhead and Underground Cables
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period(1919/20-2012/13) ▪ Age Profile - Conductor Age ▪ Conductor Voltage and phase where these are not populated in GIS. ▪ Economic Life (mean and standard deviation)
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** It was not possible to use Actual Information, and an estimate is required in relation to conductor age because Ergon Energy holds very little asset data on the installation date for overhead or underground conductors. Design processes from around 2008 create such data for

Minimum Requirements	Ergon Energy Response – Overhead and Underground Cables
	the small percentage of assets constructed since that time. In some cases where conductor phase and voltage are not populated in GIS, these were inferred from other attributes. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	<u>Overhead Conductor Age</u> In relation to overhead conductor age, Ergon Energy has developed an estimate based on the following approach: ▪ Get the latest date the line was installed, upgraded or replaced in a Smallworld design. ▪ Get the earliest pole treatment year of poles the line is mounted on. If this date is within the date range specified for the construction in the CBRM QESI inferred date table, use this date. ▪ If the conductor is mounted on “Natural Round” poles and 1955 is within the date range specified for the construction in the CBRM QESI inferred date table, use 1955. ▪ If the conductor is in NQ and its construction is one of ('200','203','204','205','207','208','211','212','213','214') use 1985. ▪ If the construction has a numeric value use the nominal year from CBRM QESI inferred date table for the construction. ▪ If the construction is non-numeric, use the alternative nominal year from CBRM QESI inferred date table for the construction. ▪ Date is unknown. In developing this estimate, Ergon Energy has made the following assumptions: ▪ The energisation processes all installed new conductor. <u>Underground Conductor Age</u> In relation to underground conductor age, Ergon Energy has developed an estimate based on the following approach: ▪ Get the installation recorded against the cable in GIS. ▪ Get the latest date the cable was installed, upgraded or replaced in a Smallworld design. ▪ Traverse the network downstream from the cable and determine the date as follows o Installation date of downstream cable. o Age of downstream switches.

Minimum Requirements	Ergon Energy Response – Overhead and Underground Cables
	o Age of downstream transformers. o Age of supporting poles. o Age of ground-mounted substation or pillar. ▪ Nominal year assigned to the QESI code associated with the cable's construction. ▪ Date is unknown RIN Template 5.2.1 is populated from Ergon Energy's GIS system for Subtransmission, Distribution and LV underground cable. The age profile has been inferred from connected assets, downstream transformers and switchgear and installation age ranges for cable types. Ergon Energy notes there is a small disparity between the total quantity of HV cable in the RIN snapshot database and the earlier data extraction for the CBRM model data. In developing this estimate, Ergon Energy has made the following assumptions: ▪ Cables for which no age was able to be determined, were added to the amounts for aged cables, in the same proportion as the aged cable to the total age for each year. **ECONOMIC LIFE** Ergon Energy has calculated the Economic life from the CBRM (Condition Based Risk Management) model using the model's "Expected Life" as the economic life and the square root of the expected life as the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as the CBRM takes into consideration the Ergon Energy Subject Matter Expert and EA Technology (Aging Asset Specialist) advice along with condition based information such as location and duty parameters.

Table 4: Service Lines

Minimum Requirements	Ergon Energy Response – Service Lines
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. SERVICE LINES BY CONNECTION VOLTAGE ▪ All Low Voltage (<= 11kV) Services are included under the two “SIMPLE TYPE” categories below: < = 11 kV ; RESIDENTIAL ; SIMPLE TYPE < = 11 kV ; COMMERCIAL & INDUSTRIAL ; SIMPLE TYPE ▪ This is because Ergon Energy has no sensible way to differentiate the “COMPLEX TYPE” Low Voltage (<= 11kV) services. < = 11 kV ; RESIDENTIAL ; COMPLEX TYPE < = 11 kV ; COMMERCIAL & INDUSTRIAL ; COMPLEX TYPE ▪ The remaining High Voltage categories of services are constructed of assets which are reported as the individual assets from which they are constructed.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category
Methodology and assumption’s used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER’s definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period(1919/20-2012/13) ▪ Age Profile ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** It was not possible to use Actual Information, and an estimate is required in relation to Service line age, because Ergon Energy holds very little asset data on quantity of or installation date for overhead and underground services, pillars and pits. Design processes from around 2008 create such data for these assets.

Minimum Requirements	Ergon Energy Response – Service Lines
	There are insufficient records to provide even a reasonable estimate of this profile. The impacts of natural disasters such as Cyclones are often considerable, and LV service failures in such situations are common. Cyclones and flooding across Queensland have had significant impact in this area. Post disaster restoration records of LV Services replacement have not proven to be effective. Records of prior Ergon Energy entities for LV Services are scant. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** In relation to service lines age, Ergon Energy has developed an estimate based on the following approach: ▪ an age profile based on the combined conductor age profile for Sub-transmission and Distribution HV and LV conductor has been used to shape the total quantity reported. ▪ In developing this estimate, Ergon Energy has made the following assumptions: ▪ Similar assets will be built at similar times as both are dependent on development – conductors are not installed unless there are customers to service. **ECONOMIC LIFE** In the absence of data, an SME estimate of the likely service life has been provided. In addition, a substitute standard deviation in the form of the accepted default value of the square root of the mean life has been provided.

Table 5: Transformers by Mounting Type and Operating Voltage

Minimum Requirements	Ergon Energy Response – Transformers by Mounting Type and Operating Voltage
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. According to further guidance provided by the AER in regards to template 5.2 in its Issues Register, Ergon Energy notes that: ▪ Transformers mounted within self-contained substations are

Minimum Requirements	Ergon Energy Response – Transformers by Mounting Type and Operating Voltage
	reported against the "kiosk" mounting type. The self-contained substations securely enclose all components of the substation within a confined unit. ▪ Furthermore, it is noted that the AER expect by their nature, that pad-mount substations are encased units and therefore transformers within these units to be classified as a kiosk mounting type.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for: ▪ AGE PROFILE Substation Transformers: o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 15 MVA AND < = 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; < = 15 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; > 15 MVA AND < = 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; > 40 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; < = 100 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; > 100 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 kV ; < = 100 MVA o GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 kV ; > 100 MVA Other Assets Including: o CURRENT TRANSFORMERS o VOLTAGE TRANSFORMERS o CAPACITOR BANKS o STATIC VAR COMPENSATOR
Source of Actual Information	Actual Information for the Age Profile substation transformers was sourced from Ergon Energy's ERP system 'Ellipse' Asset Management module.
Methodology and assumption's used in relation to Actual	The information was obtained using the installation year, this was derived from the 'Year of Manufacture' in Ellipse. This 'year of

Minimum Requirements	Ergon Energy Response – Transformers by Mounting Type and Operating Voltage
Information	manufacture' has been obtained from the manufacturer's name plate.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period (1919/20-2012/13) ▪ Age Profile (All variables excluding those listed above in Use of Actual Information) ▪ Economic Life (All variables excluding those listed above in Use of Actual Information)
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** It was not possible to use Actual Information, and an estimate is required in relation to installation year because Ergon Energy employs run to end of life strategies for a number of these assets and Year of Manufacturer/Installation has not been routinely collected. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** In relation to Age Profile Ergon Energy has developed an estimate based on the following approach: The year of installation is determine by following this hierarchy until an answer is found: ▪ COMM-DATE (Commissioning Date) nameplate against the asset in Ellipse. ▪ YOM (Year of Manufacture) nameplate against the asset in Ellipse. ▪ date_installed attribute of the asset in Smallworld. ▪ date_installed attribute of the associated substation in Smallworld. ▪ treatment year nameplate against the pole the asset is mounted on ▪ latest YOM or COMM-DATE nameplates against equipment at the GMS site the asset is mounted on. ▪ earliest premise status date for customers associated with the asset substation. Where the above logic results in blank or a non-sensible value those assets are distributed to the same shape distribution as the assets with a real or inferred age. Note, Age Profile For substation transformers >22kV (row 96 on) is predominantly actual data as only small gaps in age data exist.

Minimum Requirements	Ergon Energy Response – Transformers by Mounting Type and Operating Voltage
	In developing this estimate, Ergon Energy has made the assumption that customers are associated to the asset. Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that: ▪ A hierarchy of rules is used so that the best sources are interrogated first working down to the more tenuous connections **ECONOMIC LIFE** Ergon Energy has calculated the Economic life from the CBRM (Condition Based Risk Management) model using the model's "Expected Life" as the economic life and the square root of the expected life as the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as the CBRM takes into consideration the Ergon Energy Subject Matter Expert and EA Technology (Aging Asset Specialist) advice along with condition based information such as location and duty parameters.

Table 6: Switchgear by Voltage and Function - Fuses

Minimum Requirements	Ergon Energy Response – Switchgear by Voltage and Function - Fuses
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Note: Ergon Energy has reported all distribution fuses in the category "< = 11 kV ; FUSE". In Ergon Energy's case this will include LV, 11kV, 22kV and 33kV fuses.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the

Minimum Requirements	Ergon Energy Response – Switchgear by Voltage and Function - Fuses
	period(1919/20-2012/13) ▪ Age Profile ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** It was not possible to use Actual Information, and an estimate is required because the relevant fields are not completed in Ellipse. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** The age profile has been estimated using the assumption that each distribution transformer has one set of HV and one set of LV fuses. **ECONOMIC LIFE** In relation to Economic Life and Standard Deviation, Ergon Energy has developed an estimate based on an SME best estimate, and the square root of the mean as the standard deviation.

Table 7: Switchgear by Voltage and Function - Circuit Breakers and Switches

Minimum Requirements	Ergon Energy Response – Switchgear by voltage and function – Circuit Breakers and Switches
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category

Minimum Requirements	Ergon Energy Response – Switchgear by voltage and function – Circuit Breakers and Switches
Information	
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period(1919/20-2012/13) ▪ Age Profile ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** It was not possible to use Actual Information, and an estimate is required because the relevant fields are not completed in Ellipse. In this case the query emulates the CBRM data extraction query logic for age inferring for distribution assets. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** Switch age is determined in the following order ▪ The COMM-DATE (Commissioning Date) nameplate against the switch physical in Ellipse. ▪ The YOM (Year of Manufacture) nameplate against the switch physical in Ellipse. ▪ The year the latest design, containing an Install, Upgrade or Replace action against the switch, was energised. ▪ The age of the site on which the switch is mounted, determined as follows o For poles, get the inferred age for the pole using the logic described in the pole age profile above. o For GMS sites, get the latest Year of Manufacture or Commissioning Date nameplate values for equipment mounted on the site. o For zone substation sites, get the default CBRM date for equipment located at the zone substation. ▪ Where the above logic results in blank or a non-sensible value those assets are distributed to the same shape distribution as the assets with a real or inferred age. **ECONOMIC LIFE** Ergon Energy has calculated the Economic life from the CBRM (Condition Based Risk Management) model using the model's

Minimum Requirements	Ergon Energy Response – Switchgear by voltage and function – Circuit Breakers and Switches
	"Expected Life" as the economic life and the square root of the expected life as the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as the CBRM takes into consideration the Ergon Energy Subject Matter Expert and EA Technology (Aging Asset Specialist) advice along with condition based information such as location and duty parameters.

Table 8: Public Lighting

Minimum Requirements	Ergon Energy Response – Public Lighting
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period (1919/20-2012/13) ▪ Age Profile ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	Actual Information for the variables was sourced from Ergon Energy's Field Mobile Computing system (FMC) In order to obtain the information, it was necessary for Ergon Energy to record the year of manufacture of luminaires at time of bulk lamp replacement. In doing so, it was assumed that all lamps were replaced as a part of the bulk lamp replacement program, and that brackets were installed at the same time as luminaires as there is no asset data on brackets.

Minimum Requirements	Ergon Energy Response – Public Lighting
	AGE PROFILE It was not possible to provide Actual Information, and an estimate is required in relation to year of manufacture or install because approximately 35% of luminaires had no year of manufacture recorded. In this case the year of manufacture was assigned at random between 1990 and the last known inspection date. **ECONOMIC LIFE** It was not possible to provide Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	Ergon Energy has used SME knowledge to assign an estimate as the economic life and the square root of the life as the standard deviation.

Table 9: SCADA Network Control Master Stations, Field Devices and Local Wiring and Audio Frequency Load Control Assets

Minimum Requirements	Ergon Energy Response – SCADA Network Control Master Stations, Field Devices and Local Wiring and Audio Frequency Load Control
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period(1919/20-2012/13) ▪ Age profile ▪ Economic life

Minimum Requirements	Ergon Energy Response – SCADA Network Control Master Stations, Field Devices and Local Wiring and Audio Frequency Load Control
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to: **AGE PROFILE** As some of these projects are in implementation phase but not fully completed so installation data is not yet available. **ECONOMIC LIFE** It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	AGE PROFILE 2012/13 In relation to installed assets 2012/13, Ergon Energy has developed an estimate based on the number of projects that are in implementation or were scheduled for that time period. In developing this estimate, Ergon Energy has made the assumption that projects have commenced as scheduled. Standard Life (mean and standard deviation) In relation to Standard life (mean and standard deviation), Ergon Energy has developed an estimate based on the following approach: ▪ Manufacturer recommendations ▪ Experience with the products ▪ Component failures ▪ Technical capabilities. In developing this estimate, Ergon Energy has made the following assumptions: ▪ That all hardware is equal, for example that a 25 year old RTU should have the same service life as a brand new one.

Table 10: Protection System Field Devices and Local Wiring Assets

Minimum Requirements	Ergon Energy Response – Protection Systems, Field Devices and Local Wiring
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the

Minimum Requirements	Ergon Energy Response – Protection Systems, Field Devices and Local Wiring
	Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period(1919/20-2012/13) ▪ Age Profile ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	**AGE PROFILE** ▪ It was not entirely possible to use Actual Information, and an estimate is required in relation to relay age because incomplete records exist within the Ellipse equipment register and PDS (Protection Database System), ▪ Of the 8,845 operational relays, 2,295 (~26% of the population) have an undefined age. However, of these unknown units, 2,011 (~23% of the population) have identifiable models for which an appropriate age has been assigned. This has resulted in 284 relays (3% of the population) labelled with an unknown age. **ECONOMIC LIFE** ▪ It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** In relation to relay age, Ergon Energy has developed an estimate based on the following approach: ▪ Of the 8,845 operational relays, 2,295 (~26% of the population) have an undefined age. However, of these unknown units, 2,011 (~23% of the population) have identifiable models for which an appropriate age has been assigned. This has resulted in 284 relays (3% of the population) labelled with an unknown age.

Minimum Requirements	Ergon Energy Response – Protection Systems, Field Devices and Local Wiring
	▪ Identify Relay asset records with undefined age profile but known model type, ▪ Appropriate age assignment is accomplished by respective model Type and the known operational service. In other words, evenly distributing an installation age between the known years for which that particular model was first utilised and the last known year it was retained, ▪ This data was also compared with relay replacement data to verify and/or assign an appropriate installation year and hence an age. In developing this estimate, Ergon Energy has made the following assumptions: ▪ Relay replacement data is accurate as obtained from PDS and corporate data source, Ergon Energy considers that the best estimate has been provided for relay age on the basis that: ▪ Age assignment is based upon the known years for which that particular model was first utilised and the last known year it was retained. This is considered an improvement upon the relay type (i.e. electromechanical pre-1980, static 1980 to ~1990, and numeric ~1990 onwards) as it narrows down the possible age range to a more precise period, ▪ In addition, this data has been cross-referenced and verified against the corporate database and Capital relay replacement projects. **ECONOMIC LIFE** Relay Mean Life is calculated upon known relay age profiles detailing both an installation and replacement/removal year (calculated as ~15 years). It is assumed that PDS, Ellipse and corporate databases having cross-referenced age and replacement profiles that this would offer reassurance and a level of accuracy and confidence in the data presented. The Relay Standard Deviation is calculated as the square root of the Relay Mean Life (calculated as ~4 years). It is assumed that PDS, Ellipse and corporate databases having cross-referenced age and replacement profiles that this would offer reassurance and a level of accuracy and confidence in the data presented. Ergon Energy considers the best estimate has been provided for Economic Life as the SME has considerable knowledge and experience and has been based on a failure rate study.

Table 11: Communications and Local Wiring Assets

Minimum Requirements	Ergon Energy Response – Communications and Local Wiring Assets
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Source of Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Methodology and assumption's used in relation to Actual Information	Not applicable. Ergon Energy has provided Estimated Information, in accordance with the AER's definition for the variables in this asset category
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period (1919/20-2012/13) ▪ Age Profile ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, and an estimate is required in relation to Age Profile because after a detailed analysis of the available data in Ellipse, Stride, VQSM, Small World, Ubinet and consultation with SME's was completed, it was confirmed that the base data is incomplete. A high level of interpretation was required from SME's to come close to the number of assets installed. Even with this interpretation, the data is still inadequate and the financial year of installation is not able to be identified in the majority of cases. It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.
How the estimate has been produced	**AGE PROFILE** As we do not have detailed data on our legacy installations, we have spread the legacy asset population equally over the period from 1988/9 to 2008/09. All physical UbiNet data for Communication Network Assets and Site Infrastructure was allocated to FY 2011/2012 and spread over three financial years of 2010/11 to 2012/13 through percentages installed, based on expenditure per financial year and calculated by subject

Minimum Requirements	Ergon Energy Response – Communications and Local Wiring Assets
	matter experts All Linear Asset data totals were taken from Stride as they appeared to be more accurate while the financial year breakdowns for Linear Assets were based on Small World installation dates. Combined the two data sets gave totals installed and corresponding financial years. **ECONOMIC LIFE** The mean economic life has been based on SME consultation. The Square root of the mean economic life based on SME's recommendation has been used in place of the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as the SME has considerable knowledge and experience and recent failure data was also considered.

Table 12: Other Assets

Minimum Requirements	Ergon Energy Response – Other Assets (CT's, VT's and CP's)
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.
	Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for: ▪ Age Profile
Source of Actual Information	Actual Information for the variables was sourced from Ergon Energy's ERP system 'Ellipse' Asset Management module.
Methodology and assumption's used in relation to Actual Information	The information was obtained using the installation year, this was derived from the 'Year of Manufacture' in Ellipse. This 'year of manufacture' has been obtained from the manufacturer's name plate.
Use of Estimated Information	Ergon Energy has provided Estimated Information in relation to the following variables, for all Asset categories in the Asset Group, for the period (1919/20-2012/13) ▪ Economic Life
Why is it not possible to use Actual Information, and why an estimate is required	It was not possible to use Actual Information, for Economic Life given economic life is an estimate in accordance with the definitions provided by the AER. Estimation was therefore applied. The standard deviation is also therefore an estimate as it is derived from the mean economic life.

Minimum Requirements	Ergon Energy Response – Other Assets (CT's, VT's and CP's)
How the estimate has been produced	Ergon Energy has calculated the Economic life from the CBRM (Condition Based Risk Management) model using the model's "Expected Life" as the economic life and the square root of the expected life as the standard deviation. Ergon Energy considers the best estimate has been provided for Economic Life as the CBRM takes into consideration the Ergon Energy Subject Matter Expert and EA Technology (Aging Asset Specialist) advice along with condition based information such as location and duty parameters.

Category Analysis RIN Basis of Preparation

Template 5.3 Maximum Demand at Network Level

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 5.3 Maximum Demand at Network Level of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 5.3 Maximum Demand at Network Level (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 5.3 Maximum Demand at Network Level, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 5.3 Maximum Demand at Network Level (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 5.3 Maximum Demand at Network Level

Table 5.3.1 - Raw and Weather Corrected Coincident MD at Network Level (Summed at Transmission Connection Point)

Table 1: Addressing Minimum BOP requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. Ergon Energy has also provided data across all years in relation to Embedded Generation, Weather Corrected Network Coincident Maximum Demand (for both 10% POE and 50% POE). These cells were shaded orange allowing for ‘blacking out’ had such information was not collected. The raw maximum demand used for weather correction is adjusted demand. Embedded generation taken into account at the system level includes scheduled and unscheduled generation
	Ergon Energy has prepared the information provided in Template 5.3, Table 5.3.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER’s definition, for all variables in Table 5.3.1 for all initial regulatory years (2008/09 to 2012/13).
Source of Actual Information	Actual Information for the variables was sourced from Ergon Energy’s Statistical Metering Database (SMDB). Ergon Energy maintains a series of secure, managed databases known as the SDMB that contain historic demand and weather (sourced from the Bureau of Meteorology data). A full version control of the metered data is maintained within SMDB and the database is regularly backed-up. Access to the environment is secure and provided only to those persons who require access in order to conduct and manage the load forecasting process, and planning studies, with any changes to the datasets tracked and recorded. The database is constantly being fed new demand data from a variety of sources including *AEMO* accredited Meter Data Agents (MDA) for all *NEM* meter data file formatted (MDFF) data for Transmission *Connection* Points (and hence Ergon Energy System Total Demand).
Methodology and assumption’s used in relation to Actual	Relative to the information provided for variables in the Table 5.3.1, it was necessary for Ergon Energy to apply the following methodologies and assumptions:

Minimum Requirements	Ergon Energy Response
Information	▪ *RAW NETWORK COINCIDENT* Maximum demand obtained from SMDB. ▪ *DATE MD OCCURRED* as extracted from the SMDB aligned with maximum peak. ▪ *HALF HOUR TIME PERIOD MD OCCURRED* was read from the SMDB, as being the same as the National Electricity Rules (NER) defined "trading interval". The value reported for this variable is the 30 minute period ending on the hour or on the half hour over which the Maximum demand was recorded. The interval is identified by the *time* at which it ends. ▪ WINTER/SUMMER PEAKING data reported aligns with Ergon Energy's own network demand forecasting cycles, under which Summer Peak is considered to occur in the period 1 October to 31 March inclusive while Winter Peak is considered to occur in the period 1 April to 30 September inclusive. This does not correspond with the form of the definition of a regulatory year due the seasonal nature of customer demand for energy on the network assets. For clarity, Ergon Energy forecasts with the latest available recorded annual maximum demands which are derived from measurements over the 12 month period ending summer. That is to say, for example, for the purpose of forecasting zone substation maximum demand, 2012/2013 is the 12 month period ending 01/03/2013 00:00, of which winter MDs are recorded during period 01/04/2012 00:30 - 01/10/2012 00:00 and summer MDs are recorded during period 01/10/2012 00:30 - 01/04/2013 00:00. ▪ EMBEDDED GENERATION data was obtained from the SMDB as the aggregation of embedded generation downstream of a substation. Maximum demands are extracted both at time of Seasonal System Maximum Demand (COINCIDENT) and aggregate embedded generation Seasonal Maximum Demand (NON-COINCIDENT). Only those sites where Ergon Energy has interval meters installed is used in this variable. A negative sign is used to indicate directional flow of energy. ▪ *WEATHER* CORRECTED *(10% POE) NETWORK COINCIDENT MD*, and *WEATHER CORRECTED (50% POE) NETWORK COINCIDENT MD* In order to obtain weather adjusted peak demand, Ergon Energy has employed a methodology involving: o Daily temperature maximum and minimum observations are obtained from the Bureau of Meteorology for weather stations within the Ergon Energy franchise area. o In reference to temperature correction, actual summed coincident demand at the Network Terminal Connection Point and embedded generation as read from SMDB is weather corrected using the following: Constructing a multivariate maximum demand equation for both summer and winter season

Minimum Requirements	Ergon Energy Response
	separately over the last 14 years, using variables of Temperature (Maximum and minimum), Gross State Product (source Australian Bureau of Statistics-ABS), Air-conditioning Data (load) (Source Energy Consult) are obtained over the data set. These coefficients and equation is used to model demand. o Daily historical weather parameters (temperature maximums and minimums) are passed through the multivariate equation and maximum annual demand is obtained. o The listing of annual peak demand is made for all set of consistent temperature to produce an associated histogram o The annual peak demands were analysed / measured from the histogram to obtain 10 POE and 50POE values. o In doing so, it was assumed that temperature correction using temperature data from all years is an appropriate technique applied to the current customer base to produce temperature corrected peak demand.
Use of Estimated Information	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
Why is it not possible to use Actual Information, and why an estimate is required	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.
How the estimate has been produced	Not Applicable. Ergon Energy has provided Actual Information, in accordance with the AER's definition.

Category Analysis RIN Basis of Preparation

Template 5.4 Maximum Demand and Utilisation at Spatial Level

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 5.4 Maximum Demand and Utilisation at Spatial Level of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 5.4 Maximum Demand and Utilisation at Spatial Level (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 5.4 Maximum Demand and Utilisation at Spatial Level, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 5.4 Maximum Demand and Utilisation at Spatial Level (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 5.4 Maximum Demand and Utilisation at Spatial Level

Table 5.4.1 – Non Coincident & Coincident Maximum Demand

Table 1: Addressing Minimum BOP requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. Of note, where an asset was not commissioned or de-commissioned for that regulatory year, the rating field is left blank. A ‘zero’ is a possible reading for maximum demand, therefore it would be inappropriate to enter ‘zero’ for demand prior to commissioning or following decommissioning. Where available and/or relevant, Ergon Energy has also provided data in relation to Substation Rating, Adjustments – Embedded Generation, Weather Corrected Maximum Demand (for both 10% PoE and 50% PoE). Alternatively, these cells (shaded orange allowing for ‘blacking out’ had such information was not collected) have been blacked out or left ‘zero’ in line with the abovementioned comment. On the Estimates (E) worksheet it should be noted that for better of a more appropriate entry Ergon Energy has entered the Coincident date. ▪ DATE MD OCCURRED - NON-COINCIDENT ▪ HALF HOUR TIME PERIOD MD OCCURRED - NON-COINCIDENT
	Ergon Energy has prepared the information provided in Table 5.4.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER’s definition, for all variables of Table 5.4.1. for a given substation (zone or subtransmission) where metering is available and functional for any given year.
Source of Actual Information	Actual information for the following variables was sourced from the Substation Investment Forecasting Tool (SIFT), a joint Ergon Energy / Energex solution for, among other requirements, the containing of data for the production of network demand forecasts and the process of developing the network demand forecasts. The raw maximum demand used for weather correction is adjusted demand. ▪ WEATHER CORRECTED MD 10% PoE ▪ WEATHER CORRECTED MD 50% PoE Actual information for the following variable was sourced from the

Minimum Requirements	Ergon Energy Response
	Statistical Metering Database (SMDB) which is the data warehouse of SCADA and metering data (*refer to Basis of Preparation for Template 5.3 for further background on SMDB):* ▪ RAW ADJUSTED MD ▪ DATE MD OCCURRED ▪ HALF HOUR TIME PERIOD MD OCCURRED ▪ ADJUSTMENTS - EMBEDDED GENERATION. (Ergon Energy only has unscheduled Generation in the subtransmission network) ▪ WINTER/SUMMER PEAKING For the following variable NCC ratings were sourced from Ergon Energy network rating group's Network Rating Database. For substations where this was not available, Nameplate rating information was sourced from the SIFT system: ▪ SUBSTATION RATING
Methodology and assumption's used in relation to Actual Information	Relative to the provision of information in Template 5.4, Table 5.4.1 – Non-Coincident and Coincident Maximum Demand, Ergon Energy makes the following comments (including specific definitions of variables and sub categories applied): ▪ Those substations in group "SUBTRANSMISSION SUBSTATION" are Bulk Supply Substations which are wholly owned and maintained by Ergon Energy. ▪ No Transmission Connection Point (TCP) substations supply Subtransmission voltages (>=66kV) have been listed. ▪ Transmission Connection Point (TCP) substations supply distribution voltages (<=33kV) have been listed with the ZONE SUBSTATION grouping. ▪ Those substations that are privately owned have been listed as" (###) Private Substation" where '###' is a unique code used by Ergon Energy forecasters to explicitly identify the RIN entry for internal audit purposes. ▪ Those substations that are Ergon Energy owned and supply a single consumer have been listed as" (###) Private Substation" where '###' is a unique code used by Ergon Energy forecasters to explicitly identify the RIN entry for internal audit purposes. ▪ SUBSTATION RATING is taken to be the Normal Cyclic Capacity (NCC). NCC is the maximum permissible peak daily loading for a given load cycle that the substation can supply each day of its life. ▪ SUBSTATION RATING - Normal Cyclic Capacity (NCC) rating (n capacity) which does not vary between non-coincident and coincident peaks. Where no NCC rating is available, name-plate rating has been used for Ergon Energy assets, and Authorised Maximum Demand for customer-owned assets.

Minimum Requirements	Ergon Energy Response
	▪ RAW ADJUSTED MD – Cleansed (of switching events) Native Demand. This is an aggregate of the “As Delivered” substation raw readings with any downstream embedded generation raw readings. Maximum demands are extracted both at time of Seasonal System Maximum Demand (COINCIDENT) and Substation Seasonal Maximum Demand (NON-COINCIDENT). Effects of “temporary closure of major industrial customers” are not accounted for as Ergon Energy does not measure energy not supplied to a consumer. The MD reported is the highest average demand recorded over a half hour period within a season. ▪ Reported MVA values are at the time of RAW ADJUSTED MD MW readings. Ergon Energy currently does not store independent seasonal MVA peak readings. ▪ HALF HOUR TIME PERIOD MD OCCURRED – is the same as the NER definition of a “trading interval”. The value reported for this variable is the 30 minute period ending on the hour or on the half hour over which the MD was recorded. The interval is identified by the *time* at which it ends. ▪ DATE MD OCCURRED – The date on which the native non-coincident and native coincident maximum demand of a substation was recorded in date format dd/mm/yyyy. ▪ WINTER/SUMMER PEAKING data reported aligns with Ergon Energy’s own network demand forecasting cycles, under which Summer Peak is considered to occur in the period 1 October to 31 March inclusive while Winter Peak is considered to occur in the period 1 April to 30 September inclusive. This does not correspond with the form of the definition of a regulatory year due the seasonal nature of customer demand for energy on the network assets. For clarity, Ergon Energy forecasts with the latest available recoded annual maximum demands which are derived from measurements over the 12 month period ending summer. That is to say, for example, for the purpose of forecasting zone substation maximum demand, 2012/2013 is the 12 month period ending 01/03/2013 00:00, of which winter MDs are recorded during period 01/04/2012 00:30 - 01/10/2012 00:00 and summer MDs are recorded during period 01/10/2012 00:30 - 01/04/2013 00:00. ▪ ADJUSTMENTS - EMBEDDED GENERATION – is the aggregation of embedded generation downstream of a substation. Maximum demands are extracted both at time of Seasonal System Maximum Demand (COINCIDENT) and aggregate embedded generation Seasonal Maximum Demand (NON-COINCIDENT). Only those sites where Ergon Energy has interval meters installed is used in this variable. A negative sign is used to indicate directional flow of energy, negative being energy delivered to the Ergon Energy network from the embedded generator. ▪ COINCIDENT – variable measure at the time of Ergon Energy

Minimum Requirements	Ergon Energy Response
	System Maximum Demand. ▪ NON-COINCIDENT – variable measured at time of substation or embedded generation annual maximum demand over the regulatory period. Of note, over the required period there have been a number of large customer transfers to Powerlink TNSP from Ergon Energy LNSP. As this load has not disappeared from the Queensland economy and for consistency of demand to GSP correlation these Transmission Network Connected Premises (TNCP) have been removed from the history provided. These TNCP connections have been at transmission voltages, not involving Subtransmission substations or zone substation assets. The AER requirement is to include these TNCP load history where a segment of a DNSP's network is transferred to the TNSP. As there have been no asset transfers from Ergon Energy with these TNCP transfers the AER ruling is deemed to have been adhered to. **Weather Correction of Raw Readings:** Daily temperature maximum and minimum observations are obtained from the Bureau of Meteorology for weather stations within the Ergon Energy franchise area. Raw aggregate coincident Native (with energy supplied by downstream embedded generation) substation demands are sourced from the Statistical Metering Database (SMDB) and weather corrected using the following: Coefficients for a multivariate equation using variables of Temperature (Maximum and minimum), Saturday, Sunday and holidays are obtained over each year's data set. These coefficients and equation are used to model maximum demands. Historical weather parameters (temperature maximums and minimums) are passed through the multivariate equation to produce modelled daily peak demand commensurate with the daily temperatures. The daily demand figures were used to obtain annual peak demand figures over all previous temperature data sets. The annual peak demands were analysed to obtain 10 PoE and 50PoE values for each year. In doing so, it was assumed that temperature correction using temperature data from all years is an appropriate technique applied to the current consumer base to produce temperature corrected peak demand. The magnitude of temperature correction to the peak MW demand, expressed as a ratio of that demand is applied to the raw MVA value to provide temperature adjusted peak demand in MVA.
Use of Estimated Information	Ergon Energy has used Estimated load readings when neither statistical metering nor SCADA is installed at a substation, or in case where metering has failed for an extended period of time.

Minimum Requirements	Ergon Energy Response
Why is it not possible to use Actual Information, and why an estimate is required	In cases where neither statistical nor SCADA metering is installed at a substation estimates of demand are derived from consumer billed kWh, deemed energy profiles and network topology. In cases where metering has failed over long periods of time estimates are derived from linear interpolation of like monthly readings and annual peaks drawn from these estimated monthly peaks.
How the estimate has been produced	In cases where statistical metering has failed over long periods of time estimates are derived from linear interpolation of like monthly readings (with a time stamp period the same as the previous year) and annual peaks drawn from these estimated monthly peaks. In these cases the time of peak is estimated to be the same as the previous.

Category Analysis RIN Basis of Preparation

Template 6.3 – Sustained Interruptions

1 July 2008 to 30 June 2013

Forward

In response to requirements of the AER's Category Analysis RIN, and specific to the information presented in Template 6.3 – Sustained Interruptions of Ergon Energy's completed 2008/09-2012/13 Category Analysis RIN templates (08/09-12/13 CARIN Templates), this Basis of Preparation document has been prepared by Ergon Energy with a view to:

- demonstrate how the information provided in relation to Template 6.3 – Sustained Interruptions (and associated Tables and/or variables) is consistent with the requirements of the Notice;
- explain the source from which Ergon Energy obtained the information provided in the template; and
- explain the methodology Ergon Energy applied to provide the required information, including any assumptions Ergon Energy made.

In circumstances where Ergon Energy has provided input using Estimated Information in relation to Template 6.3 – Sustained Interruptions, Ergon Energy has made comment herein as to:

- why an estimate was required, including why it was not possible to use Actual Information; and
- the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is a best estimate, given the information sought in the Notice.

As relevant, Ergon Energy has provided additional detail beyond the minimum requirements if it was considered it may assist a user to gain an understanding of the information presented in the regulatory templates.

No additional requirements were identified as requiring provision of additional information or attachment/s over and above completed templates or Basis of Preparation.

This Basis of Preparation document should be read in conjunction with the information presented in Template 6.3 – Sustained Interruptions (Actual, Estimated or Consolidated) in Ergon Energy's completed 08/09-12/13 CARIN Templates.

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

Template 6.3 – Sustained Interruptions

Table 6.3.1 - Sustained Interruptions to Supply (from 1 July 2008)

Table 1: Addressing Minimum BOP requirements

Minimum Requirements	Ergon Energy Response
Consistency with the requirements of the Notice	Ergon Energy has populated all variables for cells shaded yellow as required by the Notice. As permitted under the Notice, for cells shaded orange, Ergon Energy has not populated "Detailed Reason For Interruption" (column 'G') (i.e. cells have been blacked out), given: ▪ Ergon Energy currently doesn't collect or report this information; and ▪ Ergon Energy has identified this in the basis of preparation.
	Ergon Energy has prepared the information provided in Template 6.3 Sustained interruptions, Table 6.3.1 - Sustained interruptions to supply in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice. Information provided in Template 6.3 Sustained interruptions includes both planned and unplanned interruptions to supply. Only those events noted under paragraph 18.4 (a)(1)-(6) and (b) (that is to say, those allowable under the STPIS scheme) have been applied in preparing data. In accordance with further clarification received from the AER via its issues register, Ergon Energy notes that for periods prior to the implementation of STPIS, the TMED boundaries were calculated as follows: ▪ 2008/09 data was calculated using daily unplanned SAIDI over the 2003/04 to 2007/08 period (after removing the effect of any exclusions permitted under clause 3.3 and 5.4 of the STPIS); ▪ 2009/10 data was calculated using daily unplanned SAIDI over the 2004/05 to 2008/09 period (after removing the effect of any exclusions permitted under clause 3.3 and 5.4 of the STPIS).
Use of Actual Information	Ergon Energy has provided Actual Information, in accordance with the AER's definition, for all variables in Table 6.3.1 - Sustained interruptions to supply for all of the initial regulatory years (i.e. 2008/09–2012/13).
Source of Actual Information	Actual Information for the variables was sourced from Ergon Energy's Outage Management System FDRSTAT.
Methodology and assumption's used in relation to Actual Information	In order to obtain the information, Ergon Energy applied the following assumptions: **Assumptions applied across all years** ▪ Completed Planned and Unplanned Sustained Interruptions are

Minimum Requirements	Ergon Energy Response
	included. (Interruptions greater that one minute) ▪ Feeder Classifications: Urban, Short Rural & Long Rural. ▪ Financial Years 2008/09 – 2012/13 inclusive (Between 1 July and 30 June). ▪ Number of customers affected by the interruption: Calculation is the Customers Interrupted on the Feeder. ▪ Average duration of sustained customer interruption (minutes): Calculation is the Customer Minutes experienced on the Feeder DIVIDED BY Customers Interrupted on the Feeder. ▪ Effect on unplanned SAIDI (by feeder classification): Calculation is the sustained unplanned Customer Minutes experienced on the Feeder DIVIDED BY Average Number of Customers of the Feeder's classification. (Planned and other STPIS excluded events have no effect on unplanned SAIDI or SAIFI and as such will be reported as '0'.) ▪ Effect on unplanned SAIFI (by feeder classification): Calculation is the sustained unplanned Customers Interrupted on the Feeder DIVIDED BY Average Number of Customers of the Feeder's classification. (Planned and other STPIS excluded events have no effect on unplanned SAIDI or SAIFI and as such will be reported as '0'.) In this regard, for distribution customer numbers utilised, Ergon Energy notes that: ▪ Ergon Energy's 2010/11 Annual Performance RIN used monthly customer numbers as the denominator whereas the Category Analysis RIN for 2010/11 uses the Average number of customers as the denominator therefore the will be a slight variance. ▪ Category Analysis RIN uses the average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period) as the denominator by Feeder's classification against all data required for the AER Category Analysis RIN. In doing so, it was noted that: ▪ Currently Ergon Energy does not collect or report the detailed information for the outage data requested in column G "Detailed reason for interruption" and therefore unable to provide this detail and the cells have been blacked out. ▪ Currently Ergon Energy does not collect reason detailed information for Single Customer Events therefore Ergon Energy has included these events under the "Reason for interruption" Third Party Grouping. ▪ Public Safety Isolations exclusions were not assessed by Ergon Energy and therefore not applied, prior to the financial year 2010/11. ▪ Prior to the year 2010/11, outages relating to interruptions resulting

Minimum Requirements	Ergon Energy Response
	from to service fuse and beyond faults (SF&B) was not routinely cleansed by Ergon Energy, which may result in an overstatement of SF&B faults applied in years 2005/06-2009/10. **Major Event Day details** For financial years 2010/11 and 2011/12 Ergon Energy applied an outage management practice that involved the creation of a number of child outage events within the outage management system to capture small pockets of off supply customers at a point in time when the distribution network was reinstated following a significant outage events. ▪ "Parent Outages" where created to record Outages affecting Feeders on a Major Event Day. The Parent Outage caused a loss of supply to a group of customers that had initially occurred on a Major Event Day. ▪ When some assets were fixed the Parent Outage was closed and '1st' and '2nd' child outages were created and used to continue the outage data capture for the Customers that still had a loss of supply from the Initial Parent Outage. ▪ This is not a normal practice at Ergon Energy but this was exercised to handle the outstanding volume of outages occurred during the MED Days in 2010/11 and 2011/12. ▪ A number of these significant outage events occurred on identified MEDs. As a result the data provided presents a number of smaller outage events identified as MED exempt that do not have a commencement date aligned to a nominated MED. ▪ These outages have been excluded from the normalised SAIDI and SAIFI reports. ▪ The linkage between the original parent outage and each individual child outage was established through a rigorous analysis and review process to ensure accuracy and integrity of the reported performance data. The identified child outage eventsThe Child Outages where: 729422, 729425, 730973, 732660, 732746, 721745, 721914, 721925, 721973, 722033, 722034, 722036, 730277, 722793, 723595, 725259, 724669, 729305, 826385, 829204, 826000, 826276, 826317, 825391, 825525, 825563, 825950, 826233, 826394, 827676, 825815, 825824, 825826, 825892. Ergon Energy suspended this practice prior to the commencement of the 2012/13 reporting year.