ERGON ENERGY

Annual Performance Regulatory Information Notice

Submission (Audited)

1 July 2014 to 30 June 2015

2 November 2015

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CONTENTS

GLOSSARY

ACRONYM	GLOSSARY TERM
2014-15 AP RIN	Ergon Energy 2014-15 Annual Performance Regulatory Information Notice
ABS	Australian Bureau of Statistics
ACCC	Australian Competition & Consumer Commission
ACS	Alternative Control Services
AER	Australian Energy Regulator
AER FDD	2010-2015 Distribution Determination
CAC	Connection Asset Customers
CAM	AER approved Cost Allocation Method
Capex	Capital expenditure
CBD	Central business district
CBRM	Condition Based Risk Management models
CICW	Customer Initiated Capital Works
CMS	Call Management System
CNOC	Communications Network Operations Centre
CPI	Consumer Price Index
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme (AER)
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme (AER)
E&E	Efficiency & Effectiveness Program
EECL	Ergon Energy Corporation Limited
EEQ	Ergon Energy Queensland Proprietary Limited
EETL	Ergon Energy Telecommunications Pty Ltd
EG	Embedded Generator
ENCAP Review	Queensland Electricity Network Capital Program Review 2011
Ergon Energy	Ergon Energy Corporation Limited
Excel	Microsoft Excel
FACTS	Feedback and Claim Tracking System
FDRSTAT	FeederStat

ACRONYM	GLOSSARY TERM
FiT	Feed-in-tariff
GIS	Geographic information system
GSL	Guaranteed Service Level
GUI	Graphical User Interface
GWh	Gigawatt hour
HV	High voltage
ICC	Individually Calculated Customer
IVR	Interactive Voice Recording
J-AMIT	Joint Asset Management Inspection Tool
KM	Kilometre
kV	Kilovolt
LV	Low voltage
LR	Long Rural
MDA	Meter Data Agent
MDI	Maximum Demand Indicator
MED	Major event day
MSS	Minimum Service Standard
MVA	Megavolt ampere
MVAR	Megavar reactive component of power
MW	Megawatt
NARMCOS (Data Model)	Network Assets Replacement Maintenance Capex / Opex Summary Model
NER	National Electricity Rules
NMI	National Metering Identifier
Nominal	With respect to dollars – means dollar of the day
Notice	Regulatory Information Notice
Opex	Operational expenditure
POE	Probability of Exceedance
PTRM	Post Tax Revenue Model
QTC	Queensland Treasury Corporation
RAB	Regulatory Asset Base
Real	With respect to dollars – means constant dollars at a specific date.
RIN	Regulatory information notice
ROAMES	Remote Observation Advanced Modelling Economic Simulation

ACRONYM	GLOSSARY TERM
Rules	National Electricity Rules
SAC	Standard Asset Customer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory control and data acquisition
SCS	Standard Control Services
SFB	Service Fuse and Beyond
SMDB	Statistical Metering Database
SPARQ	SPARQ Solutions Pty Ltd
SR	Short Rural
STPIS	Service Target Performance Incentive Scheme (AER)
SWER	Single Wire Earth Return
UbiNet	Ubiquitous Network
UR	Urban
VT	Voltage Transformer
W	Watt
WACC	Weighted Average Cost of Capital
YOM	Year of Manufacture
ZSS	Zone-Substation

1. INTRODUCTION

On 28 September 2012 the Australian Energy Regulator (AER) issued a Regulatory Information Notice (Notice) under Division 4 of Part 3 of the National Electricity (QLD) Law (NEL) to Ergon Energy Corporation Ltd (ABN 50 087 646 062) (Ergon Energy).

The Notice requires Ergon Energy to provide and to prepare and maintain the information in the manner and form specified in the Notice.

The AER requires the information for the performance or exercise of its functions or powers conferred on it under the NEL or the National Electricity Rules (NER), namely to:

- monitor the compliance of Ergon Energy with the 2010-2015 Distribution Determination (AER FDD);
- publish reports relating to the financial or operational performance of Ergon Energy; and
- prepare for the making of future distribution determinations to apply to Ergon Energy.

Pursuant to sections 28F(1)(a) and 28M of the NEL, the Notice requires Ergon Energy to:

- provide in writing the information specified in Schedule 1 to the Notice;
- prepare and maintain the information in the manner and form specified in Schedule 2 to the Notice;
- verify, by way of a statutory declaration, the information specified in the Notice in accordance with Appendix D to the Notice;
- audit the information specified in accordance with Appendix E to the notice;

and deliver the said information electronically to AERInquiry@aer.gov.au, on or before 5:00 pm Australian Eastern Daylight Time on 13 November 2015 in respect of information for the 2014-15 regulatory year (1 July 2014 to 30 June 2015) (the 'Submission'). The submission is to be accompanied by the Audit and Review Report(s) and a signed Statutory Declaration over audited information.

Of note, on 6 August 2014, the Notice was amended by the AER following a review of overlaps of reporting requirements with other RINs issued to Ergon Energy (economic benchmarking and category analysis). The review took into account written representations from Ergon Energy, and resulted in an amended Annual Performance RIN, and reissued workbooks containing the financial and non-financial templates applicable to 2013-14 and 2014-15. Amongst other changes, the AER removed the requirement for the Annual Performance RIN to be accompanied by a Board Resolution.

It is also noted that the information provided in response to this Notice will constitute the provision of an annual report for the purposes of paragraph 3.1.4.1 of the AER, *Demand management incentive scheme for Energex, Ergon Energy and ETSA Utilities 2010–15*, October 2008.

Accordingly, Ergon Energy is pleased to submit this Submission (audited) in relation to the 2014-15 Regulatory Year (**Ergon Energy 2014-15 Annual Performance RIN, Submission**), as made by:

Ergon Energy Corporation Limited

PO Box 1090

Townsville Qld 4810

Enquiries or further communications in relation to this submission, should be directed to:

Jenny Doyle

Group Manager Regulatory Affairs

Ergon Energy Corporation Limited

Email: jenny.doyle@ergon.com.au

Mobile: 0427 156 897

2. CONFIDENTIAL INFORMATION

2.1 Requirement

In issuing its Notice to Ergon Energy, the AER noted that it would treat information in accordance with the relevant provisions of the NEL, NER and the AER's information policy, if Ergon Energy makes a claim for confidentiality over any information provided in accordance with the Notice issued. To do so, Ergon Energy must:

- for all information and documents, clearly identify and mark the part of the information that Ergon Energy consider confidential;
- provide reasons supporting each confidentiality claim. High-level reasons, which generally support confidentiality claims, are insufficient. In attempting to explain why particular information is confidential, please focus on the detriment that disclosing the information might cause Ergon Energy; and
- submit both a public and confidential version of the information, redacting information in the public version that Ergon Energy considers confidential.

It is noted that the AER's *Confidentiality Guidelines*[1] set out the framework for how the AER will handle confidentiality claims and requirements for Ergon Energy.

A confidentiality claim, by itself, is insufficient to prevent disclosure. Both the NEL and the *Competition and Consumer Act 2010 (Cth)* provide for the AER to disclose confidential information in certain circumstances. In particular, section 28ZB of the NEL allows the AER to disclose information where:

- disclosure would not cause detriment to the information provider or the person from whom the information provider received the information; or
- public benefit in disclosing the information outweighs that detriment.

Making a confidentiality claim in the manner mentioned above will reduce the chance that the AER will exercise these powers. Ergon Energy notes the AER would provide notice and an opportunity to comment prior to exercising these powers.

2.2 Response

Ergon Energy notes that whilst regard has been given to the AER's Confidentiality Guidelines in preparation of its 2014-15 Annual Performance RIN, no claims for confidentiality have been identified in regards to this Submission.

Ergon Energy contacted its independent auditors (the Queensland Audit Office and Parsons Brinkerhoff) to advise the AER's ability to disclose audit or review reports issued to Ergon Energy in respect of its 2014-15 Annual Performance RIN, subject to any confidentiality claims made. Confirmation was obtained from the auditor agreeing to the release of audit or review reports / audit opinion.

[1] http://www.aer.gov.au/node/18888

3. DATA TEMPLATES

RIN - Schedule 1 paragraph 1.1 (a)-(b), Schedule 2 paragraph 1.1(a)-(d) and Appendix B and C (templates)

3.1 Requirement

Schedule 1, paragraph 1.1 (a) of the Notice as amended by the AER on 6 August 2014, requires Ergon Energy to provide all information required in the Regulatory Accounting Statements, being the information required in the Excel workbook attached as Appendix B to the Notice, as amended by the AER on 6 August 2014. Furthermore, Schedule 1 paragraph 1.1(b) requires the provision of the information required in the Non-Financial Regulatory Templates in the Excel workbook attached at Appendix C to the Notice, as amended by the AER on 6 August 2014.

The AER requires Ergon Energy to verify information specified in Appendix E to the Notice, as provided in the Regulatory Accounting Statements and Non-Financial Regulatory Templates by way of an Audit in accordance with that Appendix E.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

Data for cells in the Excel workbooks coloured grey or containing formulae do not require input and must not be amended by Ergon Energy.

3.2 Ergon Energy 2014-15 Annual Performance RIN templates

3.2.1 Completed RIN Templates

Ergon Energy's Submission of the completed 2014-15 Annual Performance RIN templates (2014-15APRIN Templates), being the Microsoft Excel workbooks at Appendix B and Appendix C to the Notice, are provided as attachments to this response as follows:

- Regulatory Accounting Statements, and
- Non-Financial Regulatory Templates.

Refer to Table 21-1: List of Attachments.

Of note, Ergon Energy made the following minor amendments to tables within templates, as detailed in Table 3-1 and Table 3-2 below. Importantly, these changes have either been agreed with the AER or don't alter the requirements of the RIN; rather they provide for improved disclosure or alternatively, amend perceived errors in drafting of table headings.

Table 3-1: Amendments to Templates: Appendix B – Regulatory Accounting Statements

RIN Template	RIN Template Reference	Amendment
Template 7 Capital expenditure for Tax Depreciation	Table 1: Tax Standard Live and Capital expenditure Additions – Standard control services (SCS)	Heading was amended to change Live to Lives (plural)

RIN Template	RIN Template Reference	Amendment
Template 5 Capital expenditure	Table 2: ACS Table 3: Other services	Table numbers for Table 2: ACS and Table 3: Other services were renamed to Table 4 and Table 5 respectively, to maintain sequential numbering within Template 5.
Template 10 Network operating costs (including overheads)	Table 6: Non–network alternatives (demand management) operating costs that are not captured by the Demand Management Incentive Scheme (DMIS) ($ nominal)	Total cells were issued with a hard coded number – 0 (zero), Ergon Energy has deleted the zero's and inserted a formula to sum the impact for all projects.

Table 3-2: Amendments to Templates: Appendix C – Non Financial Regulatory Templates

RIN Template	RIN Template Reference	Amendment
Template 3 Outcomes Customer Service	Table 3: Customer service Customer complaints (number) Complaint - technical quality of supply	Overridden formula in cell H65 - Table 3: Customer service which was linking to cell H27 - Table 2: Complaints - technical quality of supply, due to unavailability of data which meets the complaints definition in the RIN. Also refer to the assumptions and methodologies for Template 3 at Table 4-29 to 4-31.
Template 5b Network data - Feeder Reliability	Table 1: Annual Feeder Reliability Data Maximum demand (MW)	As confirmed with the AER via email on the 3 September 2013, the measure (MW) in the heading for Maximum Demand (cell H9) has been amended to MVA. This aligns with the STPIS (and QLD Electricity Industry Code) that was in force for 2014-15) definitions for Feeder Categories which require the assignment of categories to be based on feeder maximum demand (per km) expressed in MVA (not MW).
Template 5d Outcomes Planned Outages	Table 1: Planned outages	As advised by the AER via email on 22 August 2013, Ergon Energy has amended Template 5d to report planned SAIDI and System Average Interruption Frequency Index (SAIFI) in total. The current row headings (after removing excluded events) are not meaningful for planned outages and have been deleted from the template.

3.2.2 Key Information Systems Used

The table below gives a listing and brief description, of key information systems that Ergon Energy currently uses to provide its Distribution Services and which have been utilised in providing the information required in the templates (referred to as relevant in Basis of Preparation responses provided in section 4).

It is emphasised that this is not an exhaustive list of all of the information systems that Ergon Energy uses. For further explanations of specific processes and systems used to report RIN requirements refer to section 4 in this document.

Table 3-3: Key Information Systems used by Ergon Energy

System	Description
Artemis 7	Manages investment portfolio including project planning, scheduling and tracking, program and project governance and financial and resource management
DCOS Model	Distribution Cost of Supply (DCOS) Model is used in the network tariff setting process, where the output of the model is 'forecast revenue' for each customer group to be recovered via distribution tariffs. The DCOS Model output displays forecast revenues by geographic zones (East, West, Mount Isa) and customer categories (ICC, CAC, EG, SAC, UnMet&STL) with the Annual Charge disaggregated by Fixed Charge, Actual Demand Charge, Capacity Charge, and Volume Charge.
ECORP	ECORPMAIN contains the network asset topology utilised by FeederStat, Connect, Switching Sheet Writer and reliability reporting apps. The ECORP model hierarchy is primarily manually maintained by Network Data Officers and Customer Connection Officers i.e. association of premises with substations. An automated process (GELO) exist which updates selected feeders (approx. 3 feeders) in ECORPMAIN from NETAPP-GISEP. The ECORPMAIN model contains network objects like substations and switches required to model network connectivity it does not contain other assets e.g. poles, conductors, streetlights etc.
Ellipse	Ellipse is a large Enterprise Resource Planning (ERP) application used to manage assets, works, finance, supply chain, logistics, human resources and payroll. This application represents the logical group of modules of the Ellipse application which support the Financial Management sub segment. Ellipse was commissioned on 4 September 2006 as the Management and Financial reporting tool. The chart of accounts structure includes a district code and four segments forming an account line of four alphabetic and seventeen numeric characters. District: Separate legal entities of Ergon Energy consisting of parent entity and subsidiaries; Responsibility Centre: Business unit groups responsible for revenues, expenses for a function/ location; Activity: Type of work being undertaken; Product: Product or service being provided, for example High Load Escort; and Element: the nature of the revenue received or expense incurred. Each revenue, cost element, asset and liability that when combined constitute the

System	Description
	sum of Ergon Energy activities, and any associated adjustment to these, must have its origin in an audited Statutory Accounts
FACOM	Ergon Energy's Customer Information System (CIS) which contains customer and premises data. Ergon Energy Queensland's (EEQ) retail customers (Tier 1) and Ergon Energy Corporation Limited's distribution only accounts for Tier 2 (market) customers are managed in FACOM. EEQ's retail customers are billed from FACOM. Information can be extracted from this database using Ergon Energy's ECORP or NetBill applications.
FeederStat	Ergon Energy's outage management system. It pinpoints where a particular premises is located and what feeder or substation it is connected to. FeederStat is used when faults and outages are being analysed and facilitates the NCC logging fault related calls as they are received and providing information to customers on restoration times. FeederStat is the primary outage management system employed by Ergon Energy to capture, record, action and report: planned and unplanned outages. FeederStat was internally developed by Ergon Energy and is a common application used across all sites with access to Oracle which is used to both input and extract outage data and information
NEMLink (MDP)	The Meter Data Provider's Market Gateway
NetBill	Network Bill production for market and non-market customers.
ROAMES	Remote Observation Automated Modelling Economic Simulation (ROAMES) LiDAR program. ROAMES technology originally developed by Ergon Energy and partner organisations creates precise, 3D geo-spatial representations of network assets such as substations, poles and wire infrastructure to be displayed in a Google Earth-like database. The sheer size of Ergon Energy's distribution area was a key motivator for finding smarter ways of managing the assets and the surrounding environment. It is anticipated that the information ROAMES provides will result in reduced maintenance and planning costs, while also increasing the safety and reliability of electricity supply for our customers and communities. The large volume of data captured during ROAMES flights is processed to enable reliable and precise measurement of Ergon Energy's electricity network and surrounding objects such as buildings, terrain and vegetation. Information is then used to create a precise, virtual representation of Ergon Energy's network infrastructure throughout Queensland, providing vital information for more effective and cost efficient vegetation maintenance and asset planning. From 1 March 2014, this capability is supplied via a Service Level Agreement from an unrelated corporation called ROAMES Asset Services Pty Limited.
Supervisory Control and Data Acquisition (SCADA)	While SCADA is a general term, it is used within Ergon Energy to refer specifically to the ABB system used for Network Operations.
Smallworld	A geographic information system used to manage the spatial location of assets.

System	Description
Smallworld Oracle Replicated (SOREP) Spatial database.	Replicated version of Smallworld Electrical Data. Reference by Aires, Mapguide, Google Earth, Schematics etc.
Statistical Metering Database (SMDB)	Statistical Metering Database. Consists of Access databases maintained by Ergon Energy's Planning department to capture the history of Ergon Energy's interval data for demand and weather (sourced from the Bureau of Meteorology data).

4. ASSUMPTIONS AND METHODOLOGIES

RIN - Schedule 1 paragraph 1.1 (c)(i)-(ii)

4.1 Requirement

Schedule 1 paragraph 1.1 (c) requires explanation relative to the 2014-15 AP RIN Workbooks, being the Microsoft Excel workbooks at Appendix B and Appendix C of the Notice as amended by the AER on 6 August 2014, where applicable, of:

- the assumptions and methodologies underlying the information provided; and
- each instance where the information cannot be provided or is not provided in full.

The AER requires Ergon Energy to verify this information, by way of a statutory declaration in accordance with Appendix D to the Notice.

4.2 Assumptions & Methodologies Applied by Ergon Energy

4.2.1 General Comments

Ellipse was commissioned on 4 September 2006 as the Management and Financial reporting tool. The chart of accounts structure includes a district code and four segments forming an account line of four alphabetic and seventeen numeric characters.

- District: Separate legal entities of Ergon Energy consisting of parent entity and subsidiaries;
- Responsibility Centre: Business unit groups responsible for revenues, expenses for a function/ location;
- Activity: Type of work being undertaken;
- Product: Product or service being provided, for example High Load Escort; and
- Element: the nature of the revenue received or expense incurred.

Each revenue, cost element, asset and liability that when combined constitute the sum of Ergon Energy activities, and any associated adjustment to these, must have its origin in an audited Statutory Accounts.

4.2.2 Additional Attachments

The additional attachments noted in the table below are requirements that entail provision of additional information or attachments over and above completed templates or Basis of Preparation.

Responses to these requirements are made as attachments to this Submission, for templates as summarised below. Refer also to Table 21-1: List of Attachments.

Table 4-1: Additional Attachments

Title	Attachments	Relevance
EECL 1415 APRIN_S1 RSUP	Supplementary Templates; Explanations for material variances (Refer to templates within attachment)	Revenue items

4.2.3 Regulatory Accounting Statements

4.2.3.1 Template 1 – Income Statement

Template 1 requires Ergon Energy to report the Income Statement (Table 1). Ergon Energy understands that the information gathered will be used by the AER to monitor revenues for each service classification. Elements of the information are used to calculate financial ratios, used for intra and inter-business comparison and the AER will also monitor and report on information such as divided payments, tax payments, depreciation and profit.

Ergon Energy makes the following comments with regard to the compilation of the Income Statement template.

Table 4-2: Template 1 - Income Statement

Items	Underlying Assumptions and methodology
Distribution revenue	Revenue is measured at the fair value of the consideration received or receivable. As a network service provider, Ergon Energy receives Distribution Use of System (DUOS) income. As per AASB 118 Revenue, the Economic Entity is using accrual accounting for unbilled network charges. All values have been extracted from Ellipse. Within the audited statutory accounts column the revenue recognised is inclusive of revenue from regulated and unregulated assets. The statutory accounts have been prepared on an unbilled basis in 2014-15. The adjustments column consists of: ▪ Transmission Use of System (TUOS) revenue (net of TUOS cross boundary revenue), which is reported in the Income Statement Category, TUOS; ▪ Unregulated revenue (identified by the activity segment of the chart of accounts); ▪ Cross boundary revenue; and ▪ Net current year solar expense. The value of SCS distribution revenue is calculated using total DUOS revenue less: ▪ TUOS revenue (net of cross boundary revenue); ▪ DUOS cross boundary revenue; ▪ TUOS cross boundary revenue; and ▪ Unregulated revenue. This calculation enables the SCS distribution revenue to be presented on an unbilled basis. The Alternative Control Service (ACS) revenue is obtained from an activity code in the general ledger. The ACS revenue is reported on an accrual basis.
TUOS Revenue	The value of TUOS revenue was extracted from the Ergon Energy billing records. Information to present the TUOS revenue on an unbilled basis was not available when the income statement was prepared. The external provider of the unbilled information will be able to provide this in the future. At the present time the billing

Items	Underlying Assumptions and methodology
	information is the most meaningful for income statement purposes.
Cross Boundary Revenue	DUOS & TUOS revenue received from Essential Energy for 33kV and 66kV lines, based on metered data for 2014-15.
Gain on disposal of fixed assets	The disposal of an item of Property, Plant & Equipment (PP&E) may occur in a variety of ways (e.g. by sale or scrapping at the end of its useful life). Ergon Energy's Asset Management Policy and Strategies discusses when assets should be disposed i.e. after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Assets disposed of can be regulated or unregulated and can be readily identified as they are recorded in different categories within the fixed assets register that identify if the asset provides SCS, ACS or unregulated services in accordance with the AER FDD and the NER. The figure reported in the statutory accounts is the amount of proceeds that exceeds the carrying amount of the item. The assets register reports upon asset disposal by detailed category and by a mapping exercise. These are converted into AER reporting categories.
Contributions	Under Ergon Energy's Capital Contribution Policy (covering both cash contributions and gifted assets) contributions are accounted for as revenue. This aligns with the transitional clause 11.16.10 of the NER which allows Ergon Energy to maintain its current approach for the treatment of capital contributions whereby the annual capital contributions are included in its Regulatory Asset Base (RAB) and instead, a deduction is made from annual revenue caps in order to determine the Annual Revenue Requirement. Any difference between forecast and actual capital contributions is managed through the unders/overs process annually. Cash capital contributions are received from small customers for subdivisions and other small customer initiated capital works (CICW) and gifted assets relate to Urban subdivisions and Commercial and Industrial customers. Contributions for ACS are identifiable by separate codes within Ergon Energy's general ledger. The adjustment between the Audited Statutory Accounts and the Regulated Distribution business relates to contributions received from unregulated sources, including the isolated networks.
Interest Income	Ergon Energy holds bank accounts which service all activities of the consolidated group. Therefore, the interest income received from underlying banks accounts relates to all services provided by the parent entity. As such an allocation basis using PP&E ratios has been applied to pro-rata interest income across Ergon Energy's classification of services. The values have been extracted from Ellipse and a manual calculation has been applied to report the disaggregation required. The adjustment column consists of interest income apportioned to unregulated services. In addition to the interest earned on its general purpose bank account, interest is also earned on loans to SPARQ and unwinding of discount on under recovery of

Items	Underlying Assumptions and methodology
	regulated revenue. This is disclosed in the adjustments column.
Use of revenue cap assets for non-SCS purposes	Amount is calculated solely for regulated reporting purposes and hence the full number is shown as an adjustment. The adjustment is calculated by using data extracted from the general ledger, as well as a number of causal allocators (e.g. employee numbers) to arrive at the reported values.
Other Revenue	Other revenue relates to a variety of receipts, including meter removals, recoverable works, sale of inventory etc. These are categorised across service classifications according to their classification in the Ellipse general ledger. The value in the adjustments column is the revenue from unregulated activities.
TUOS Costs	TUOS expense was obtained from an examination of the charges levied upon Ergon Energy and those passed on to retailers. TUOS expense is presented on an accrual basis from information in the General Ledger. The adjustments column includes Cross Boundary revenue, Non-Regulated revenue, Network Support costs, prior years avoided TUOS. Current year actual avoided TUOS has been added.
Cross boundary charges	Ergon Energy notes that the definition for 'Cross Boundary Charges', is the cost of using another DNSP's distribution network therefore Ergon Energy has included costs of using Energex's distribution network and costs for use of Ergon Energy's unregulated 220kV network. This is because Ergon Energy is operating under a transitional rule which allows it to pass through charges it incurs for use of Ergon Energy's unregulated 220kV network as a Designated Pricing Proposal Charge or 'TUOS' charge (refer transitional rule 11.39 of the NER). The AER FDD also requires Ergon Energy to maintain a TUOS unders and overs account, and to submit a record of all transmission related payment (including any transitional charges under rule 11.39) to the AER as part of its Annual Pricing Proposal.
Maintenance	The Ergon Energy general ledger records maintenance costs in a series of codes that differentiate between SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER. The identification of maintenance costs is performed by mapping these codes into their appropriate RIN reporting category
Operating Expenses	The Ergon Energy general ledger records operating costs in a series of codes that differentiate between SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER. The identification of maintenance costs is performed by mapping these codes into their appropriate RIN reporting category. In the annual statutory accounts the feed-in tariff and guaranteed service level payments are classified as negative revenue, in the RIN these amounts are included in the adjustments column as they are reported as operating costs. Also

Items	Underlying Assumptions and methodology
	included in the adjustments column is an amount for over-absorbed overheads at year end. This adjustment is made to comply with the AER approved CAM.
Depreciation	The Statutory approach for calculating depreciation has been used on a straight line basis by reference to the useful life of each item of PP&E, other than freehold land and easements which are not depreciated. An assessment of useful lives is performed annually. All values have been extracted from Ellipse. The audited statutory accounts column includes depreciation and amortisation for the parent company EECL. It consists of amortisation of intangible assets such as computer software, licences and customer contracts and relationships, and depreciation for supply systems, power stations, buildings, and other plant and equipment, as well as impairment of non PP&E assets, i.e. Impairment of Doubtful Debts. The adjustments column relates to depreciation and amortisation of Ergon Energy's unregulated power station assets comprising isolated generation and distribution systems, and other unregulated assets. The unregulated and isolated assets and assets that provide ACS are identified by the use of different asset categories within the fixed assets register
Finance Charges	Interest expense is the result of Ergon Energy's total borrowings which are used to fund its entire capital works program. Hence this amount has been apportioned across the reporting categories on the basis of the PP&E ratios. The adjustment column is therefore an estimate of the interest expense that relates to the funding of these unregulated assets.
Use of revenue cap assets for non-SCS purposes	This adjustment is to allow for the use of regulated assets for non-SCS purposes. The adjustment is calculated by using data extracted from the general ledger, as well as a number of causal allocators (e.g. employee numbers) to arrive at the reported values. This number is calculated solely for regulated reporting purposes.
Loss on disposal of fixed assets	The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale or scrapping at the end of its useful life). Ergon Energy's Asset Management Policy and Strategies discusses when assets should be disposed i.e. after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Assets disposed of can be regulated or unregulated - these can be readily identified as providing SCS, ACS, unregulated or isolated services in accordance with the AER FDD and the NER as they are recorded in different categories within the fixed assets register. The figure reported in the statutory accounts is the proceeds minus the carrying amount of the item when the proceeds are the lesser amount.
Impairment Losses (nature of the impairment loss)	Impairment losses relates to the reversal of an impairment loss booked in 2013-14 for unregulated assets determined from a review of the General Ledger.

Items	Underlying Assumptions and methodology
Other	The adjustment relates to unclassified costs of operating the isolated and unregulated assets.
Profit before tax	Revenue less expenses
Income tax expense	Income tax expense is calculated as 30% of profit before tax, for each of SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER.
Profit after tax	Revenue less expenses less tax.

4.2.3.2 Template 5 – Capital Expenditure (including overheads)

Template 5, Capital Expenditure requires Ergon Energy to provide detailed capital expenditure (Capex) information (including overheads), including SCS by reason; explanation of material differences in relation to SCS; Capex by asset class; ACS and other services spend. Other services are split into negotiated services and unregulated services. Template 5 also requires Ergon Energy to list related party transactions which are more than 5 per cent of the total SCS or ACS Capex. Further, capital contributions by asset class and disposals by asset class are required to be completed in this template.

The AER have stated that the information provided is necessary for the AER to monitor Capex and will be used to inform the assessment of Capex and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following general comments in respect of Capex.

Capex is recorded as either Direct Purchases, or Project costs.

Direct purchases relate to the purchase of a complete asset from an outside supplier such as motor vehicles or computers, whereas a construction asset (primarily its distribution assets) is treated as project costs. With constructed projects, one of two data sources is used depending upon whether the project is complete and capitalised into the fixed asset register or whether it remains incomplete.

Capex data is therefore drawn from three principle sources:

- Ergon Energy's general ledger;
- Ellipse Project Accounting module; and
- Microsoft Excel worksheet for categorisation of WIP construction assets based on Ellipse Estimating module data.

In all cases the total Capex is reconciled back to the totals contained in the general ledger.

Direct Purchases were extracted from a transactional level report direct from the general ledger which provides details about the asset purchased. This permits reporting in the appropriate asset category as required in the Regulatory Accounting Statements.

Where the Project has been capitalised, Business Property Unit codes (BPU) are recorded against the Project to assign the asset category for capitalisation. Using an Access Database, a mapping process is undertaken to identify the AER asset category. This process also identifies unregulated Capex to be excluded.

Where the Project remains under construction and is yet to be capitalised, details are extracted from the Ellipse estimating module to ascertain the types of assets under construction. Once the information is extracted into Excel a mapping table is applied to covert the type of assets into the RIN asset categories.

More specifically, Ergon Energy makes the following comments regarding costs reported in the template tables:

- Actual Capital Contributions are not recorded against specific asset categories in the Ellipse general ledger. Therefore, an apportionment process has been applied to report against asset categories. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module.
- Within the Ergon Energy Ledger shared costs that have been charged via the overhead allocation process in accordance with the CAM are identified by an element code of 8100 within the chart of accounts hierarchy. The numbers shown in the template are a summary of these overhead costs by asset category.

Ergon Energy makes the following comments as relevant to the tables in Template 5.

Table 4-3: Template 5 - Capex – SCS by Reason

Items	Underlying Assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the Order of the Australian Competition Tribunal (ACT), and adjusted these amounts for actual consumer price index (CPI). The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2014-15 regulatory year in the Post Tax Revenue Model (PTRM) used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM is based on the relevant Australian Bureau of Statistics (ABS) March to March CPI weighted average of 8 capital cities result (catalogue # 6401.0) sourced from the ABS website. In order to disaggregate the forecasts for Template 5, a separate Excel spread sheet was produced to recast the AER approved forecast Capex and forecast capital contributions into the RIN formats and into $2014-15 terms. These figures were then reconciled against the forecast Capex and forecast capital contribution figures derived at the macro level from the CPI adjusted PTRM noted above.
Asset replacement	Ergon Energy's Capex is recorded in the general ledger against a series of codes that specify the nature of the Capex cost. The identification of the amount to report as asset replacement involves summarising the amounts recoded against the appropriate code
Corporate initiated augmentation	Ergon Energy's Capex is recorded in the general ledger against a series of codes that specify the nature of the Capex cost. The identification of the amount to report as corporate initiated augmentation involves summarizing the amounts recoded against the appropriate code.
CICW	Ergon Energy's Capex is recorded in the general ledger against a series of codes that specify the reason for the Capex. The identification of the amount to report as CICIW is determined by summarising the amounts recorded against the appropriate code

Items	Underlying Assumptions and methodology
Reliability /quality improvement	Ergon Energy's Capex is recorded in the general ledger against a series of codes that specify the nature of the Capex cost. The identification of the amount to report as reliability/quality Improvement involves summarising the amounts recorded against the appropriate code.
Other	Ergon Energy's Capex is recorded in the general ledger against a series of codes that specify the nature of the Capex cost. The identification of the amount to report as other involves summarising the amounts recorded against the appropriate code.
Non-system assets	Non-System Capex is identified through an analysis of the relevant general ledger codes
Total distribution	Formula summing all distribution Capex.

All material differences identified in Table 1 are to be explained in Table 2. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per the AER FDD adjusted by CPI to the relevant regulatory year dollar value, or the ACT's orders), and Ergon Energy's reported actual amount.

In July 2014, the Queensland Government amended Ergon Energy's Distribution Authority to reflect:

- a change to the security criteria from a deterministic approach to a probabilistic approach. The new criteria adopted by Ergon Energy increases the focus on customer service levels and comprises two parts: (i) mandatory investment, for a base level of network security, known as the Safety Net; and (ii) reliability based investment, for security improvements above the Safety Net requirements, based on a Value of Customer Reliability (VCR) approach;
- a relaxation of the security criteria for distribution planning from a 75% utilisation to an 85% trigger point;
- monitoring and reporting on Safety Net measures to effectively mitigate low probability high consequence events; and
- the flat-lining of Minimum Service Standards (MSS) provisions at 2010-11 levels, as previously incorporated in the Electricity Industry Code (the Code)[2].

These changes in many cases reduced the future investment drivers and service level targets for augmentation and reliability investment. The impacts of these changes have been presented in Ergon Energy's recent regulatory proposals to the AER as well as its Distribution Annual Planning Report (DAPR).

Table 4-4: Template 5 - Capex - Explanation of Material Differences

Items	Underlying Assumptions and methodology
Asset replacement	Asset Replacement expenditure was less than 10% below the 2014-15 AER forecast, therefore an explanation has not been provided in accordance with the instructions.
Corporate initiated	▪ Augmentation investment in 2014-15 has been lower than expected owing to a number of investments undergoing planning and scope reviews under the new

[2] Note, the (Queensland) Electricity Industry Code was replaced by the Electricity Distribution Network Code (EDNC) on 1 July 2015.

Items	Underlying Assumptions and methodology
augmentation	security criteria (combined with updates on the demand forecast) which have resulted in identification of lower cost solutions to forecasted constraints. Additionally, a significant planned investment in the township of Moranbah that was in design phase was de-scoped based on an agreement being reached with the transmission supplier to maintain the existing connection point arrangements.
CICW	Customer initiated capital works was 57% below the 2014-15 AER forecast. ▪ Customer initiated investment in 2014-15 has been lower than expected owing to lower demand from customers proceeding with connection enquiries and applications. Generically performance against expenditure forecast for 'Domestic and Rural', 'Commercial and Industrial' customers and subdivision works has been approximately 15-23% lower than expected. However significant reductions in gifted Subdivisions assets and Large Customer Connections have been experienced of up to 50% and 83% respectively. These reductions are most pronounced in Large Customer Connections and Subdivision works owing to the higher unit cost for these connection types and the volatility these customer types experience. An additional factor that impacts the revised forecast expenditure for CICW 2014-15 year is the updated real cost escalators and overheads. ▪ These expenditure revisions are consistent with declines in Queensland non-residential investment indicators that have significantly weakened following the completion of the Curtis Island Liquefied Natural Gas (LNG) construction projects. A significant investment planned for the Cairns Northern Beaches area has been deferred from the original proposed timeline because of matters associated with relevant development and gaming licenses approvals and the overall subdued tourist activity in the Cairns area. The delay to this large customer connection project has also reduced the level of expected residential and commercial development in the suburbs surrounding the Cairns Northern Beaches associated with this development.
Reliability /quality improvement	Reliability/quality improvement was 162% above the 2014-15 AER forecast. This result was largely driven by: ▪ Reliability investment was higher than expected owing to stronger program coordination and delivery of the ACR and Gas Switch reliability improvement program. In order to meet MSS compliance a higher volume of switches was required to be installed in the 2010-15 period than compared to Ergon Energy's original Regulatory Proposal and the reduced Final Determination. The delivery time for a large program was under estimated and more switches were installed in 2014-15. This has reduced the need for Reliability Improvement investment to continue into the next Regulatory Control Period.
Other	Other capital expenditure was 44% below the 2014-15 AER forecast. This result was largely driven by: ▪ Communications and IT assets that were determined to be non-system assets were transferred out to Non System Assets; and

Items	Underlying Assumptions and methodology
	▪ The Distribution Management System (DMS) project was put on hold after the completion of the Blueprinting phase of the project which validated the estimated design, timing allocations and system integration costs for the project.
Non System Assets	Non system asset expenditure was 104% above the 2014-15 AER forecast. Actuals were greater than forecast due to: ▪ communications and IT assets were transferred to the Non-System asset category yet were originally forecast against Other System Assets; and ▪ Property Investments - Glenmore Rd, Rockhampton exceeded initial forecast expectations, whilst Garbutt recovered from its initial delays (owing to the discovery of asbestos) to also exceed forecast for 2014/15 financial year.

Table 4-5: Template 5 - Capex - ACS

Items	Underlying Assumptions and methodology
Street Lighting	Data for street lighting is extracted from the Ellipse system in the same manner described above under heading Template 5 – Capital expenditure (including overheads) with further filters applied to activity codes to obtain ACS (street lighting).
Fee based services	Capex is not incurred on Fee Based Services.
Quoted services	Ergon Energy's Capex is directly attributed in the general ledger against a series of codes that specify the reason for the Capex. The identification of the amount to report as Quoted Services involves summarising the amounts recoded against the appropriate code

Table 4-6: Template 5 - Capex - Other services

Items	Underlying Assumptions and methodology
Negotiated Services	Ergon Energy has no Negotiated Services.
Unregulated Services	Ergon Energy's Capex is recorded in the general ledger against a series of codes that specify the nature of the Capex cost. The identification of the amount to report as unregulated services involves summarising the amounts recoded against the appropriate code.

Items in the "Related Party Transactions" table, items which are more than 5% of the total SCS or ACS Capex respectively must be listed separately.

Table 4-7: Template 5 - Capex - Related party transactions

Items	Underlying Assumptions and methodology
Related Party Transactions	The value of related party transactions is identified by billings issued by Ergon Energy Telecommunications Pty Ltd (EETL) and SPARQ Solutions Pty Ltd

Items	Underlying Assumptions and methodology
	(SPARQ). The billings are allocated between (a) entities paid on behalf of; (b) Regulatory or Non-regulatory expenses; and (c) operating expenditure (Opex) or Capex expenses. Allocation between entities is established by budget allocation, while allocation between Regulatory and Non-regulatory is based on actual full year overhead allocation. Allocation between Opex and Capex for SPARQ billings is determined using the Ellipse general ledger percentage split between Opex and Capex expenditure. All EETL billings are classified as Opex.

Table 4-8: Template 5 - Capex - Capital contributions and Disposals by Asset Class

Items	Underlying Assumptions and methodology
Capital Contributions	Actual Capital Contributions are not recorded against specific asset categories in the Ellipse general ledger. Therefore, an apportionment process has been applied to report against asset categories. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module.
Disposals by asset class	The Ergon Energy fixed assets register records and reports the value of asset disposals as well as any proceeds received. This reporting is by the asset categories used in the asset register, these are mapped to the AER reporting categories using the mapping table used for the preparation of other AER templates requiring a similar dissection.

4.2.3.3 Template 7 – Capex for tax depreciation

Template 7 requires Ergon Energy to provide Tax Standard Lives and Capex additions for SCS, split into system and non-system assets. Ergon Energy understands that the information provided will be used by the AER to allow the roll forward of the RAB.

Ergon Energy makes the following comments with regards to the Tax Standard Lives.

Table 4-9: Template 7 - Capex for tax depreciation - Tax Standard Live and Capex Additions - SCS

Items	Underlying Assumptions and methodology
System Assets	The Ergon Energy Fixed Assets Register contains the capital value for all assets. It also contains standard lives which are adjusted in accordance with any revisions issued by the Australian Taxation Office. The AER asset reporting categories at times contain assets with differing lives, e.g. sub-transmission concrete poles have a different life to sub-transmission steel towers. In these instances a weighted average life, based upon the capital value was calculated and reported. Tax Lives for Land are excluded from the weighted average calculation as it is a non-depreciable asset.
Non-System Assets	Non-system assets follow the same process as used for system assets.

4.2.3.4 Template 8 – Network Maintenance (including overheads)

Table 8 requires Ergon Energy to provide information on network maintenance by category; explanation of material differences under network maintenance; and other network maintenance costs. Ergon Energy understands that the information is necessary for the AER to monitor maintenance expenditure and will be used to inform the AER's assessment of maintenance expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following comments with regards to the respective tables completed in the Network Maintenance template. Of note, Network Maintenance is readily identified by activity codes within the general ledger coding structure. A mapping and summarisation process is used to convert the costs held against specific activity codes into the reporting categories.

Table 4-10: Template 8 – Network Maintenance - Network maintenance by category

Items	Underlying Assumptions and methodology
Forecast	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2014-15 regulatory year in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM is based on the relevant Australian Bureau of Statistics (ABS) March to March CPI weighted average of 8 capital cities result (catalogue # 6401.0) sourced from the ABS website. In order to disaggregate the forecasts for Template 8, a separate Excel spreadsheet was produced to recast the AER approved forecast Opex into the RIN formats and into $2014-15 terms. These figures were then reconciled against the forecast Opex figures derived at the macro level from the CPI adjusted PTRM noted above.
Preventive Maintenance	Comprises schedule inspection and maintenance activity. This work is carried out at predetermined intervals, or in accordance with prescribed intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep Ergon Energy staff and the public safe. Work that is identified from this program can be undertaken as either asset renewal (defect manual) Capex or corrective maintenance, so that forced and corrective maintenance can be averted. The cost of preventative maintenance is identified by separate codes within the general ledger. Reporting is therefore a matter of extracting the total expenditure. The adjustment relates to the cost of preventative maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of preventative maintenance on assets that provide ACS is also identified by an activity code within the general ledger coding structure.
Corrective	Involves planned repair work identified and assessed as defects from preventative

Items	Underlying Assumptions and methodology
Maintenance	maintenance or customer reports in order to prevent an unplanned outage or dangerous electrical event. This category of work is planned and carried out regularly. The largest element of Ergon Energy's corrective maintenance program relates to vegetation management. The cost of corrective maintenance is identified by separate codes within the general ledger. Reporting involves extracting the total expenditure. The adjustment relates to the cost of corrective maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of corrective maintenance on assets that provide ACS is also identified by an activity code within the general ledger coding structure.
Forced Maintenance	Involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the distribution network to at least its minimum acceptable and safe operating condition. Although it is unplanned, an annual provision is made for this category of expenditure. The cost of forced maintenance is identified by separate codes within the general ledger. Reporting involves extracting the total expenditure. The adjustment relates to the cost of forced maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of forced maintenance on assets that provide ACS is also identified by an activity code within the general ledger coding structure.
Other network maintenance costs	Ergon Energy's maintenance costs are identified by specific codes within the General Ledger hence there are no amounts to be included in 'other'

Of note, all material differences identified in the Network Maintenance by Category table (against forecast) are required to be explained. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per the AER FDD adjusted by CPI to the relevant regulatory year dollar value, or the ACT's orders), and Ergon Energy's reported actual amount.

Table 4-11: Template 8 – Network Maintenance – Explanation of Material Differences

Items	Underlying Assumptions and methodology
Preventive Maintenance	The expenditure on Preventive Maintenance was below the AER forecast amount for 2014-15. The $32million (-25%) underspend was primarily due to the interventions initiated during 2012-13 with those now maturing and built upon during 2013-14.
Corrective Maintenance	The expenditure on Corrective Maintenance was above the AER forecast amount for 2014-15. The $2.3 million (+2%) overspend was a relatively small increase in reactive maintenance balancing off the significant reduction in Preventative Maintenance with the net result being below the forecast.
Forced Maintenance	The expenditure on Forced Maintenance was above the AER Forecast amount for

Items	Underlying Assumptions and methodology
	2014/15. ▪ The $34.5 million (+81%) overspend was primarily due to: ▪ Works associated with response to tropical cyclone totalled $13.9 million ▪ A very active storm season producing 37,700 events at an average cost of $1,677 per event ▪ Major events were excluded from the forecasts in Ergon Energy's Final Distribution Determination
Other network maintenance costs	Other network maintenance costs was less than 10% below the 2014-15 AER forecast, therefore an explanation has not been provided in accordance with the instruction.

Items in the "Other Network Maintenance Costs" item of the Network Maintenance by Category table, that are more than 5% of the total SCS or ACS network maintenance costs, are required to be separately listed.

Table 4-12: Template 8 – Network Maintenance – Other network maintenance costs

Items	Underlying Assumptions and methodology
Other network maintenance costs	All of Ergon Energy's maintenance expenditure can be identified and reported against specific categories without having to use an "other" classification.

Related Party transactions, which are more than 5% of the total SCS or ACS network maintenance costs, are required to be separately listed.

Table 4-13: Template 8 – Network Maintenance – Related party transactions

Items	Underlying Assumptions and methodology
Related Party Transactions	These are identified using billing summaries provided by SPARQ and EETL. EETL provides telecommunications to the Ergon Energy Group; the total amount is therefore classified as an Opex cost. The total billing is split between the entities in the Ergon Energy Group using the methodology specified in the CAM. The amount that relates to SCS is calculated on a pro-rata basis.

4.2.3.5 Template 10 – Network Operating costs (including overheads)

The AER have stated that the information provided is necessary for the monitoring of operating costs, and will be used to inform the AER's assessment of operating costs and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Template 10 requires Ergon Energy to provide information on network operating costs; and an explanation of material difference (10% variance between Forecast and Actual). In addition, Ergon Energy is also required to provide further dissemination of other operating costs; related party transactions; non-recurrent operating costs where items are greater than 5% of the SCS and ACS operating costs. Finally, information is required on other non-network alternatives not captured under the DMIS.

Ergon Energy makes the following comments in regards to the compilation of the Network Operating Costs template.

Table 4-14: Template 10 – Network Operating Expenditure - network operation costs

Items	Underlying Assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2014-15 regulatory year in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM is based on the relevant Australian Bureau of Statistics (ABS) March to March CPI weighted average of 8 capital cities result (catalogue # 6401.0) sourced from the ABS website.
Network operating costs	Network operating costs are separately identified in the Ellipse general ledger. Adjustments relate to amounts directly attributed to the isolated networks.
Meter reading	Costs incurred in Ergon Energy's capacity as a Metering Data Provider for Types 5, 6, and 7 metering installations and customer service activity. The cost of meter reading is identified by separate codes within the general ledger. Reporting requires extracting the total expenditure from designated codes. The adjustment relates to the cost of meter reading for customers on Ergon Energy's isolated and unregulated networks. These costs are separately identified in the general ledger
Customer service (incl. Call Centre)	Customer Service relates to the cost of providing customer service to customers. Customer Service costs is separately identified in the general ledger. The adjustment relates to the cost of providing customer service to customers on Ergon Energy's isolated and unregulated networks.
Other operating costs	The regulated component of these costs relates, in part, to the DM incentive arrangements, GSLs and over-allocated overheads which are separately identified in the Ellipse general ledger. The adjustment relates to unclassified costs of operating the isolated and unregulated assets

Of note, all material differences identified in Table 1 are to be explained in Table 2. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per 2010-15 Distribution Determination adjusted by CPI to the relevant regulatory year dollar value, or the ACT' orders), and Ergon Energy's reported actual amount.

Table 4-15: Template 10 – Network Operating costs - Explanation of material difference

Items	Underlying Assumptions and methodology
Network operating	The expenditure on Network Operating Costs was above the AER Forecast amount

Items	Underlying Assumptions and methodology
costs	for 2014-15. The $3.3 (+11%) million overspend was primarily due to costs associated with the expansion of the Communications Network Operations Centre (CNOC). The growth required in this area was unforeseen at the time of the current period submission and relates to demand for more detailed and real time network monitoring. Impacting this is the penetration of PV installation, rise in alternate energy solutions and Safety Net reliance on real time system information. The extent of these was not anticipated at the time of the forecast. Impacting to a lesser extent are costs for Embedded Generation ($0.6 million) excluded from AER forecast submission by Ergon Energy. These costs form part of Demand Management in the next regulatory period.
Meter Reading	The forecast numbers for meter reading were based on the original resourcing model which included a combination of Ergon Energy's internal meter reading workforce and external contractor workforce performing metering reading services. In May 2013 Ergon Energy implemented a full outsourcing strategy for meter reading reducing the actual unit cost per service delivery. Additionally, growth subsided below forecast expectations which resulted in less meters being read than anticipated.
Customer service (incl. Call Centre)	There was significant spend in Customer Installation Services covering customer-related activities that are ancillary to the provision of Ergon Energy's broader network, connection and metering services, including: cold water reports; check inspections; revenue protection; customer support; managing safety compliance; and customer advisory services. The actual costs exceeded forecast as a significant amount of budgeted spend was disallowed in Ergon Energy's Final Distribution Determination and Merits review associated with this category, and driven by high demand for solar photovoltaic work.
Other operating costs	Primarily driven by the increase in FiT payments paid to customers on the Solar Bonus Scheme. The spectacular growth of solar photovoltaic (PV) panels has been partly attributed to the State Government's original 44 cents per kilowatt hour feed-in-tariff (FIT). The number of premises with PV panels on Ergon Energy’s network has seen a 50-fold increase in five years and as at 30 June 2015, over 110,000 customers had connected solar PV. As around 95% are on residential premises, this represents 18.4% of Ergon Energy’s entire residential customer base, and 23.4% of all detached residential houses in regional Queensland. There was also a significant volume of PV array upgrades on 44c-eligible units, which notably increased their export capability. As a result, costs for the feed-in tariff have considerably exceeded Ergon Energy’s expectations for 2014-15. Training costs were below forecast due to a reduction in staff numbers resulting from a fall in demand and the associated reductions in the works program. As a result there is less staff to train and the focus on training has moved from attending external courses to on the job training resulting is cost savings Overheads of $21.4m were over-applied at the end of the regulatory year. In accordance with Ergon Energy’s CAM, this amount was determined to be immaterial and has not been causally allocated yet recognised as an operating cost

Items	Underlying Assumptions and methodology
	to the distribution business. Not proceeding Network Initiated Capital Works of $28.6m was written off during 2014-15. This was primarily due to the relaxation of N-1 safety criteria and the Safety Net resulting in a number of projects considered no longer necessary. A residual amount was written off for the Blueprinting Phase of the Demand Management System Project for control centre automation as it was considered uneconomically feasible to proceed.

Items in the “Other Operating Costs” item of the Operating Costs table, that are more than 5% of the total SCS or ACS network operating costs, are required to be separately listed.

For greater transparency, Ergon Energy has disclosed most items in the Other Operating Costs item, in Table 3.

Table 4-16: Template 10 – Operating costs - Other operating costs

Items	Underlying Assumptions and methodology
Other operating costs	Other operating costs are directly attributed and relate to GSLs and unclassified costs relating to the isolated and unregulated assets.

Related party transactions that are more than 5% of the total SCS or ACS network operating costs are required to be separately listed in Table 4.

Table 4-17: Template 10 – Operating costs - Related party transactions

Items	Underlying Assumptions and methodology
Related party transactions	These are identified using billing summaries provided by SPARQ and EETL. EETL provides telecommunications to the Ergon Energy Group; the total amount is therefore classified as an Opex cost. The total billing is split between the entities in the Ergon Energy Group using the methodology specified in the CAM.

Non Recurrent network operating costs that are more than 5% of the total SCS or ACS network operating costs, are required to be identified in Table 5.

Table 4-18: Template 10 – Operating costs - non-recurrent network operating costs

Items	Underlying Assumptions and methodology
Over Applied Overheads	Ergon Energy has recognised over applied overheads in Other Operating Costs in accordance with the AER approved CAM. Also refer to Template 10 Other Operating Costs.

Table 6 requires Non-Network alternatives operating costs that are not captured by the DMIS. Ergon Energy makes the following comments with respect to Template 10, Table 6.

Table 4-19: Template 10 – Non-network alternatives (demand management) operating costs that are not captured by the DMIS ($nominal)

Items	Underlying Assumptions and methodology
Non-Network Alternatives	Non-Network Alternatives (NNA) are systems and processes implemented to reduce peak demand on the shared network. As such, all expenditure is related to SCS. NNA costs are separately identified in the general ledger. “Impact on demand (MW) current year” refers to new load brought under control, additional contracted to be interrupted or removed from network loads as a result of the project in the annual reporting period. “Impact on demand (MW) project to date” refers to new load brought under control, available contracted to be interrupted or removed from network loads as a result of the project since the project commenced. Impact on demand MW was calculated from MVA assuming a power factor of 0.9. "Deferred capital costs from DM project ($'000 nominal) Current Year impact" refers to the average annual deferral value expected to be delivered by the project on successful delivery of the NNA solution. "Deferred capital costs from DM project ($'000 nominal) Whole of Project Life Impact" refers to the total deferral value expected to be delivered by the project on successful delivery of the NNA solution.”

4.2.3.6 Template 16 – Avoided cost payments

The AER has stated that this information is necessary for the monitoring of avoided cost payments, and will be used to inform the AER’s assessment of expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following comments with respect to Avoided cost payments.

Table 4-20: Template 16 – Avoided cost payments

Items	Underlying Assumptions and methodology
Avoided TUOS	The methodology used in calculating the avoided cost payments is described in Ergon Energy’s Information Guide for SCS Pricing, 1 July 2014 to June 2015 (Version 1.0, 17 June 2014). The payments are calculated by the Service Transaction Centre using the process which is described below: Clause 5.5(h) of the NER requires DNSPs to calculate "avoided charges for the locational component of prescribed TUOS services", and clause 5.5(i) requires DNSPs to calculate the amount to be passed through to an Embedded Generator (EG). This is done by: ▪ Determining the charges for the locational component of prescribed TUOS services that would have been payable by the DNSP for the relevant financial year “if the EG had not injected any energy at its connection point during that financial year”; and

Items	Underlying Assumptions and methodology
	▪ Determining "the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the DNSP, which amount will be the relevant amount for the purposes of paragraph (h) [clause 5.5(h)]". Avoided TUOS payments are made by Ergon Energy to EGs who have sought access to Ergon Energy's distribution network under clause 5.5 of the NER and who are registered as a Generator Rules Participant. Also refer to the supplementary attachment for Revenues, for a further breakdown of DUOS and TUOS. Refer to Table 21-1: List of Attachments.
Other	Nil to report.

4.2.3.7 Template 17 – Alternative control and other services

Template 17 requires reporting of ACS & other services and is required for the AER in monitoring ACS & other services, and will be used to inform the AER's assessment of expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following comments with respect to ACS and other services.

Table 4-21: Template 17 - Alternative control and other services

Items	Underlying Assumptions and methodology
ACS – fee based	ACS is directly attributed to specific general ledger product codes. Reporting is achieved by extracting from the general ledger the amounts against the relevant product codes. The split between directly attributed, overheads and revenue is performed by using codes specified in the general ledger established for that purpose. Additional analysis was completed to ensure accuracy of posting in the general ledger, as a result amendments were made to de-energisations, and project fees reported.
ACS - quoted	ACS is directly attributed to specific general ledger product codes. Reporting is achieved by extracting from the general ledger the amounts against the relevant product codes. The split between directly attributed, overheads and revenue is performed by using the codes specified in the general ledger established for that purpose. Additional analysis was completed to ensure accuracy of posting in the general ledger, as a result amendments were made to project fees reported. Of note, the ACS Quoted Service category, 'Design and construct of new large customer connection assets' is misleading due to the inclusion of the term 'new' in the service category heading. Ergon Energy notes that this service can be applied to large customers requesting a new connection to the network or an upgrade to their existing connection. It would be more appropriate for the service category to be renamed as, 'Design and construct of large customer connection assets' in recognition that the costs may relate to new or augmented connection assets. Additional analysis was performed to extract metering costs that had been included

Items	Underlying Assumptions and methodology
	in non-specific general ledger codes. This was performed through an examination of individual work orders to identify those that had a metering component that was not being costed to one of the specific general ledger codes. These were extracted and included in the appropriate metering reporting category. To ensure consistency with the Income Statement Ergon Energy has included the value of gifted large customer connection assets as revenue. In addition, Ergon Energy is unable to report ACS in the disaggregated manner listed (feeder level) as indicated during the consultation process on the 2012-15 RIN. The Ellipse system reporting for ACS is by category, not by category and feeder (urban (UR), short rural (SR), long rural (LR), isolated). There are a number of complexities in implementing system changes, which if implemented would only be valid for 2 years of this regulatory control period, as there are a number of uncertainties around the classification of services and pricing arrangements that may / may not apply to Ergon Energy's services from 2015. Data for ACS is captured in two systems, Ellipse and FACOM, of which the later interfaces into Ellipse. FACOM is in the process of being decommissioned and replaced with a new system, to progress any system changes at this point would not be considered prudent spend.
Other activities - unregulated	ACS is directly attributed to specific general ledger product codes. Reporting is achieved by extracting from the general ledger the amounts against the relevant product codes. The split between directly attributed, overheads and revenue is performed by using the codes specified in the general ledger.

4.2.3.8 Template 18 – EBSS

Template 18, Efficiency Benefit Sharing Scheme requires Ergon Energy to provide details of adjustments to controllable operating expenditure for the purposes of the operation of the AER's Electricity DNSPs, Efficiency Benefit Sharing Scheme (EBSS) (June 2008), as applicable to Ergon Energy for Opex for the current regulatory control period.

Requirements note that only superannuation costs relating to defined benefit schemes are to be reported, and only self-insurance cost categories approved in the AER's determination are to be reported.

An explanation of changes to Capitalisation Policy is also required, including a description of any items that have previously been considered as Opex items but are now considered Capex items.

In this regard, Ergon Energy has 'Nil' Capitalisation Policy Changes to report in table 2.

In completing Template 18, Opex for EBSS purposes (table 1), Ergon Energy makes the following comments.

Table 4-22: Template 18 - Opex for EBSS purposes

Items	Underlying Assumptions and methodology
Debt raising costs	Reflect the amount presented in Template 18, Table 1. This has been sourced / calculated from QTC information.
Self-insurance and insurance costs	The amount disclosed as self-insurance and insurance costs consists of: ▪ Self-insurance costs as per Template 21, Table 1 net of revenue received

Items	Underlying Assumptions and methodology
	through external funding allocated in accordance with the CAM to derive the Opex SCS related portion (Self-insurance is distributed via corporate overheads shared costs pool, ultimately allocated between Opex/Capex according to processes described in the CAM). An overhead allocation of 28.9% is used. Insurance costs are extracted from the ledger, Elements 5970-6000, and allocated in accordance with Ergon Energy's approved CAM to derive the Opex SCS related portion (Insurance costs are distributed via corporate overheads shared costs pool, ultimately allocated between Opex/Capex according to processes described in the CAM). Overhead allocation of 28.9% used (as per Self-Insurance).
Superannuation defined benefit costs	Relating to retirement scheme are extracted from the ledger, Element 6240 adjusted by a labour oncost split to derive the Opex related portion. (Superannuation defined benefits costs are distributed via the labour on-cost and corporate overhead shared costs, ultimately allocated between Opex/Capex according to processes described in the CAM). Labour oncost split of 27.7% used.
DM innovation allowance costs	Total amount of the DMIA spent in 2014-15, as per Template 20.
Other	Table Other includes ▪ Non-network alternatives costs sourced from Template 10, Table 6; ▪ Pass Through Event costs represent the actual FiT operating costs reduced by the following: payments made to customers in isolated regions, incorrect payments to customers eligible for the 8c tariff yet incorrectly paid the 44c tariff, incorrect payments to customers not eligible for a tariff yet incorrectly paid the 8c tariff and the approved FiT forecast allowance. We note the FiT cost pass through application has been prepared on an accruals basis in accordance with Chapter 6 of the NER, clause 6.6.1(j)(2).

4.2.3.9 Template 19 – Jurisdictional scheme amounts

Template 19 requires Ergon Energy to complete the table for each approved Jurisdictional Scheme. Ergon Energy understands that Jurisdictional Scheme information is used by the AER to monitor approved Jurisdictional Schemes throughout the regulatory control period.

In completing Template 19, Jurisdictional Scheme amounts, Ergon Energy makes the following comments.

Table 4-23: Template 19 - Jurisdictional scheme amounts

Items	Underlying Assumptions and methodology
Jurisdictional scheme amounts	Ergon Energy did not report any approved Jurisdictional Schemes as in 2014-15, it was not yet operating under the jurisdictional scheme cost recovery provisions in Chapter 6 of the NER.

4.2.3.10 Template 20 – Demand Management Incentive Scheme

Template 20, Demand Management Incentive Scheme requires Ergon Energy to provide all DM innovation allowance information for the relevant regulatory control period. Ergon Energy understands this information will form the basis of the AER's assessment of the DNSP's compliance with the DMIS, and its entitlement to recover expenditure under the DMIS. The AER also state the information will also assist in assessing proposals for DM expenditure in Opex and Capex forecasts submitted in a DNSP's regulatory proposals, and in the development and implementation of the DMEGCIS (Demand Management and Embedded Generation connection incentive scheme), in future regulatory control periods.

In completing Table 20.1, demand management innovation allowance (DMIA) projects submitted for approval, expenditure under the DMIS, Ergon Energy makes the following comments.

Table 4-24: Template 20 - DMIA projects submitted for approval

Items	Underlying Assumptions and methodology
DMIA projects submitted for approval	Operating costs represent those costs booked to activity code 55000 for the 2014-15 regulatory year as extracted from Ergon Energy's Ellipse financial reporting system. Activity code C2300 captures Capex costs; however no Capex costs were incurred during the 2014-15 regulatory year. For further information, Ergon Energy refers the AER to the attached **2014-15 Demand Management Innovation Allowance - Annual Report** to the AER, for the regulatory year ended 30 June 2015. Refer to Table 21-1: List of Attachments.

4.2.3.11 Template 21 – Self-Insurance

Template 21 Self-Insurance requires Ergon Energy to provide details of self-insurance events with an incurred cost of greater than $100,000 per event and self-insurance events with an incurred cost of less than $100,000.

Ergon Energy understands that information on actual, audited costs incurred by DNSPs on self-insurance events (collected annually) will assist the AER with determining an appropriate self-insurance allowance for DNSPs at the next regulatory reset.

The AER states the information is required to be reported annually so that DNSPs can clearly demonstrate (to the AER) that their business processes and reporting systems properly account for self-insurance events. This includes correctly accounting for the risks insured and costs to the DNSP.

For the purposes of completing Template 21, Self-Insurance event information has been sourced from the Claims group in Ergon Energy's Customer Service business unit. Data was extracted from the Claims system maintained by the group.

Table 4-25: Template 21 - Self-insurance events with an incurred cost of greater than $100 000 per event

Items	Underlying Assumptions and methodology
Self-insurance events	For the period 1 July 2014 to 30 June 2015 there was three (3) claims paid with an incurred cost of $372,670.74 in total and individually greater than $100,000 per claim. Ergon Energy's public liability policy has a per-claim (maintenance) deductible and an all claims (aggregate) deductible.

Items	Underlying Assumptions and methodology
	Claims that have a cost less than the maintenance deductible are fully self-insured, meaning Ergon Energy incurs the total cost of the claim with no part of it paid by the insurer. Claims that have a cost that exceeds the maintenance deductible are also fully self-insured unless the total of the excess over the maintenance deductible of all claims is greater than the aggregate deductible. Once the aggregate deductible is exceeded, the insurer pays the cost of all claims net of the maintenance deductible which applies to each claim. The maintenance and aggregate deductibles applying on Ergon Energy's policy since 2010-11 are: ▪ 2010-11 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. ▪ 2011-12 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. ▪ 2012-13 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. ▪ 2013-14 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. ▪ 2014-15 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000.

4.2.3.12 Template 22 – Change of Accounting Policy (CHAP)

Template 22 requires Ergon Energy to provide information on the aggregate effect of the change in accounting policy on the income statements and the reason for the change in accounting policy. Ergon Energy understands that the information is required by the AER to assess forecast expenditure proposed by Ergon Energy's next reset. It captures changes in accounting policy made from year to year and the effect on the Financial Statements. The AER state this information will increase transparency and accountability to stakeholders.

Ergon Energy has the following accounting policy changes for the 2014-15 year.

- AASB 9 Financial Instruments.

Ergon Energy has early adopted *AASB 9 (December 2013) Financial Instruments* in advance of the effective date. AASB9 contains new accounting requirements for financial assets and liabilities, including classification, measurement and hedge accounting. There is no impact on forecast expenditure as this change in accounting policy impacts Ergon Energy's subsidiary.

- Regulated Revenue

The Economic Entity has changed the accounting policy for regulated revenue to exclude the recognition of revenue under or over recovery adjustments. Previously distribution revenue was recognised in accordance with the regulated revenue allowed by the Australian Energy Regulator (AER) each year. Regulatory receivables or provisions were recognised on the balance sheet, representing any amounts under or over recovered respectively, due to differences in consumption compared to the estimates included in annual regulatory pricing proposals.

There is no definitive guidance on the accounting treatment for regulatory receivables or provisions within existing standards. However the AASB has commented, in response to the International Accounting Standards Board's (IASB) Invitation to Comment ITC32 Reporting the Financial Effects of Rate Regulation; that it has a view that the rights and obligations associated with rate regulation do not meet the asset and liability recognition criteria. To date, consensus has not been achieved and divergent views continue to be debated by the IASB.

The new policy, where the accrued (or deferred) revenues are not recognised, results in more reliable information to users as it reflects a closer correlation between market conditions, shareholder and other regulatory policies and profitability.

In previous years, these amounts were disclosed as “adjustments” to Distribution revenue in the Income Statement.

4.2.4 Non-Financial Regulatory Templates

4.2.4.1 Template 1a – STPIS Reliability

Template 1a requires Unplanned SAIDI and SAIFI (total, and total after removing excluded events), by each of Ergon Energy’s feeder classifications (UR, SR, LR) and also by Whole Network.

For ease of review, Ergon Energy has disaggregated comments on Template 1a (STPIS) Reliability by table, and by requirement within each table. Comments are therefore presented below, for each of SAIDI and SAIFI performance. The following general comments apply to all data presented in Template 1a.

Table 4-26: Template 1a - STPIS Reliability – Unplanned SAIDI/SAIFI

Items	Assumptions and methodology
Unplanned SAIDI / Unplanned SAIFI	Data supplied in this template is based on actual performance data. Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year. Distribution Feeders are classified as UR, SR or LR as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder’s classification at the end of the relevant regulatory year as at 30 June. Exclusions are applied in accordance with clauses 3.3(a) & (b) of the AER's Electricity DNSPs, STPIS (November 2009). In the absence of specification, Whole of Network statistics were assumed to encompass the summation of Urban, Short Rural & Long Rural (customer minutes, customer interruptions and customer numbers). In recent years Ergon Energy has developed and implemented a software application to link between the SCADA and the FDRstat to automatically and accurately create outage event records. The progressive implementation of this enhanced capability has highlighted limitations in the Ergon Energy Reliability Reporting Application. The reporting application classifies an outage event as sustained for the purpose of reliability performance reporting based on the elapsed time between the first customer interrupted and the last customer restored. All interruptions within the event classified as sustained contribute to the reported SAIDI and SAIFI performance. As a result any momentary supply interruptions within an outage event contribute to the SAIDI and SAIFI performance. The over reporting affected has a minimal impact on the accuracy of the reported performance for 2014-15, with the most pronounced effect observed in the Short Rural SAIFI with a 1.18% inaccuracy. Because effect on accuracy is low and the inaccuracy results in over reporting against STPIS, Ergon Energy believes it is not

Items	Assumptions and methodology
	material. 10 sustained events have been identified as consisting of momentary interruptions to customers. When considering the average customer interruption duration these events are identified as having an average duration of 1 minute or less. **Unplanned SAIDI and SAIFI "Total"** SAIDI/SAIFI for each feeder classification are calculated based on the following criteria: ▪ Financial Year 2014-15 (Between 1 July and 30 June) ▪ Completed Unplanned Sustained Interruptions ▪ Feeder Classifications: Urban, Short Rural & Long Rural ▪ SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers ▪ SAIFI calculation - Customer Interruptions DIVDED BY Average Number of Customers Inclusive of the following exclusions ▪ STPIS MED's ▪ Generation (Exemption clause: 3.3 (a) (2 or 3)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Jurisdictional obligation or right (Exemption clause: 3.3 (a) (7)) **Unplanned SAIDI and SAIFI "Total – after removing excluded events"** SAIDI/ SAIFI for each feeder classification was calculated based on the following criteria: ▪ Financial Year 2014-15 (Between 1 July and 30 June) ▪ Completed Unplanned Sustained Interruptions ▪ Feeder Classifications: Urban, Short Rural & Long Rural ▪ SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers ▪ SAIFI calculation - Customer Interruptions DIVIDED BY Average Number of Customers Exclusive of the following exclusions**:** ▪ STPIS MED's ▪ Generation (Exemption clause: 3.3 (a) (2 or 3)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Jurisdictional obligation or right (Exemption clause: 3.3 (a) (7)) **Unplanned SAIDI and SAIFI for Whole of Network "Total"**

<table>
<tr><th>Items</th><th>Assumptions and methodology</th></tr>
<tr><td></td><td>SAIDI/SAIFI for Whole of network are calculated based on the following criteria:
▪ Financial Year 2014-15 (Between 1 July and 30 June)
▪ Completed Unplanned Sustained Interruptions
▪ Feeder Classifications: Whole of Network (Urban, Short Rural & Long Rural)
▪ SAIDI calculation - Customer Minutes DIVIDED BY Average Number of Customers
▪ SAIFI calculation - Customer Interruptions DIVIDED BY Average Number of Customers
Inclusive of the following exclusions:
▪ STPIS MED’s
▪ Generation (Exemption clause: 3.3 (a) (2 or 3))
▪ Shared Transmission (Exemption clause: 3.3 (a) (5))
▪ Jurisdictional obligation or right (Exemption clause: 3.3 (a) (7))

<u>Unplanned SAIDI and SAIFI for Whole of network "Total – after removing excluded events"</u>
SAIDI/SAIFI for Whole of network are calculated based on the following criteria:
▪ Financial Year 2014-15 (Between 1 July and 30 June)
▪ Completed Unplanned Sustained Interruptions
▪ Feeder Categories: Whole of Network (Urban, Short Rural & Long Rural)
▪ SAIDI calculation - Customer Minutes DIVIDED BY Average Number of Customers
▪ SAIFI calculation - Customer Interruptions DIVIDED BY Average Number of Customers
Exclusive of the following exclusions:
▪ STPIS MED’s
▪ Generation (Exemption clause: 3.3 (a) (2 or 3))
▪ Shared Transmission (Exemption clause: 3.3 (a) (5))
▪ Jurisdictional obligation or right (Exemption clause: 3.3 (a) (7))</td></tr>
<tr><td>Average Distribution Customer Numbers</td><td>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) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
Average number of distribution customers for whole of network is the average of</td></tr>
</table>

Items	Assumptions and methodology
	the total numbers of customers on all three feeder classifications (UR, SR and LR) at the beginning of the reporting period (1 July) and the total number of customers at the end of the reporting period (30 June).

4.2.4.2 Template 1b – STPIS Customer Service

Template 1b Customer Service requires Ergon Energy to enter STPIS information concerning customer service parameters set out in the AER's Electricity Distribution Network Service Provider (DNSP), STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period. All results reported in Total, and after removal of excludable events.

Information is not required to be completed by Ergon Energy on new connections, streetlight repairs and responses to written enquiries (excluding Saturdays, Sundays and Public Holidays).

Ergon Energy makes the following comments in regards to the completed table for telephone answering in Template 1b.

Table 4-27: Template 1b - STPIS Telephone Answering

Items	Assumptions and methodology
Telephone Answering	Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls. Between 1 July 2014 and 23 May 2015 Ergon Energy used a telephony platform provided by Avaya to route telephone calls to agents. From 23 May 2015 to 30 June 2015 a new system, supplied by Cisco, was brought in to replace the Avaya platform. Both systems provide a mechanism to distribute calls to Ergon Energy operators at the Customer Solutions Centre (CSC) and also enable reporting of call activity. Reportable items for both systems include but are not limited to: ▪ Recording volume of calls received at the call centre; ▪ Recording the length of time between a caller entering the system and the call answered by an operator; and ▪ Recording the length of time between a caller entering the system and the caller abandoning the call. The system plays an Interactive Voice Recording (IVR) message prior to queuing the call for response by an operator. As stipulated in Appendix A of the STPIS, the time measured for a call begins after the caller decides to remain on the line after the IVR is played. During the period that the Avaya system was in place data was extracted to a data warehouse on a daily basis. This data was then extracted from the warehouse using a system called Brio Intelligence which was used to place data into an excel spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx). Data was cross checked at the end of each month by extracting calls from the Avaya CMS Supervisor using functions within the systems Graphical User Interface (GUI) to ensure that the call numbers entered on a daily basis match the calls shown as offered for the month. Following the installation of the Cisco platform data was extracted directly from the Cisco reporting system, Cisco Unified Intelligence

Items	Assumptions and methodology
	Centre (CUIC). A report is run in this system on a daily basis which provides the number of calls presented to agents with the output saved into a spreadsheet. The main spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx) then imports the call data via lookup formulas. Where major event days (MED) have been declared these dates have been entered in the relevant monthly tab with formulas in place to exclude these calls from the STPIS calculations. All monthly totals are shown on the “YTD Results” summary tab of the main spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx) with annual totals for all calls and calls with approved exclusions removed. This data can then be entered into the parameters listed in Table 1 of the RIN.

4.2.4.3 Template 1c – STPIS daily performance

Template 1c STPIS daily performance, requires Ergon Energy to enter daily STPIS information concerning both reliability and customer service parameters set out in the AER's Electricity DNSPs, STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period.

The AER state the information is required is relative to Unplanned SAIDI/SAIFI only. The excluded events to be removed from the data refer only to events listed in clause 3.3(a) of the STPIS, with respect to reliability data, and in clause 5.4(a) of the STPIS with respect to customer service parameters.

Ergon Energy makes the following comments in this regard, for Reliability and Customer Service data.

Table 4-28: Template 1c - STPIS Daily performance data

Items	Assumptions and methodology
Daily performance data Customer Service	Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls. Between 1 July 2014 and 23 May 2015 Ergon Energy used a telephony platform provided by Avaya to route telephone calls. From the 23 May 2015 to 30 June 2015 a new system, supplied by Cisco, was brought in to replace the Avaya platform. Both systems provide a mechanism to distribute calls to Ergon Energy operators at the Customer Solutions Centre (CSC) and also enable reporting of call activity. Reportable items for both systems include but are not limited to: ▪ Recording volume of calls received at the call centre; ▪ Recording the length of time between a caller entering the system and the call answered by an operator; and ▪ Recording the length of time between a caller entering the system and the caller abandoning the call. The system plays an Interactive Voice Recording (IVR) message prior to queuing the call for response by an operator. As stipulated in Appendix A of the STPIS, the time measured for a call begins after the caller decides to remain on the line after the IVR is played. During the period that the Avaya system was in place data was extracted to a data

Items	Assumptions and methodology
	warehouse on a daily basis. This data was then extracted from the warehouse using a system called Brio Intelligence which was used to place data into an excel spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx). Data was cross checked at the end of each month by extracting calls from the Avaya CMS Supervisor using functions within the systems Graphical User Interface (GUI) to ensure that the call numbers entered on a daily basis match the calls shown as offered for the month. Following the installation of the Cisco platform data was extracted directly from the Cisco reporting system, Cisco Unified Intelligence Centre (CUIC). A report is run in this system on a daily basis which provides the number of calls presented to agents with the output saved into a spreadsheet. The main spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx) then imports the call data via lookup formulas. Where major event days (MED) have been declared these dates have been entered in the relevant monthly tab with formulas in place to exclude these calls from the STPIS calculations. All daily totals are shown in each of the monthly tabs of the main spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx) and enable entry of daily data to be entered into the parameters listed in Table 3 of the RIN.

4.2.4.4 Template 1f – STPIS GSL

Template 1f requires Ergon Energy to provide information on the AER's GSL scheme. Ergon Energy understands that the information is collected by the AER to inform the application of the STPIS to the DNSP in future regulatory periods. The AER state this information is also collected to monitor network performance, and may be used in performance reports. It is noted that if the AER's GSL scheme has been applied at any time during the regulatory year, Table 1f.1 must be completed. However, if the scheme has not been applied during the regulatory control period, then Ergon Energy does not need to complete this table.

The AER's GSL Scheme did not apply to Ergon Energy at any time during the regulatory year, therefore reporting for this template does not apply.

4.2.4.5 Template 3 – Outcomes Customer Service

Template 3 requires Ergon Energy to provide information on quality of supply, complaints pertaining to technical quality of supply and customer service. Ergon Energy understands that the information provided will be used to monitor the service performance of Ergon Energy and assist the AER understand service outcomes for customers. The AER also state the information will inform the AER's assessment of future service improvement expenditure proposals by the DNSP. As with information provided in other templates the information provided may be used in performance reports.

Table 1 Quality of Supply is not required to be completed.

Ergon Energy makes the following comments on the Complaints – Technical quality of supply.

Table 4-29: Template 3 - Outcomes Customer Service - Complaints - Technical Quality of Supply

Items	Assumptions and methodology
Complaints by category (%); and	Ergon Energy is unable to report Template 3 Table 2: Complaints – technical Quality of Supply information in accordance with the 'complaint' definition in the

Items	Assumptions and methodology
Complaints by Likely Cause (%)	RIN at the level of dissemination required. The RIN defines 'Complaint' and 'Complaints – technical quality of supply', as: ▪ 'Complaint' means a written or verbal expression of dissatisfaction about an action, a proposed action, or a failure to act by a distributor, its employees or contractors. This includes failure by a distributor to observe its published practices or procedures; ▪ 'Complaints – technical quality of supply' means the total number of complaints made to Ergon Energy including all written or emailed complaints, and complaints to the call centre, where the complaint raised issues about voltage variations. Ergon Energy in the past reported complaints in the RIN dissemination required under the Queensland Competition Authority (QCA) Service Quality Guidelines from its system FDRSTAT. However, the term complaints was defined differently: ▪ Complaints - Complaints are to be reported in accordance with Australian Standard 4269:1995, which defines a complaint as 'any expression of dissatisfaction with a product or service offered or provided'. ▪ Ergon Energy's system FDRSTAT captures calls at the first point of contact at this level of dissemination, not a complaint as defined in the RIN. If the RIN definition for complaints, had been more generalised the template would have been populated in accordance with the below table

Table 4-30: Template 3 - Outcomes Customer Service - Complaints - Technical Quality of Supply (under first point of call criteria)

	2014-15
	Complaints - technical quality of supply - number
Complaints by category (%)	
Low voltage supply	16.9
Voltage dips	2.8
Voltage swell	24.3
Voltage spike (impulsive transient)	1.6
Waveform distortion	2.3
TV or radio interference	4.4
Noise from appliances	0.4
Other	47.3
Complaints by Likely Cause (%)	
Network equipment faulty	6.0

	2014-15
Network interference by NSP equipment	0.4
Network interference by another customer	17.4
Network limitation	0.4
Customer internal problem	1.0
No problem identified	53.9
Environmental	18.7
Other	2.2

Ergon Energy makes the following comments with regards to Template 3, Customer Service.

Ergon Energy maintains a customer information system known as FACOM. All customers on Ergon Energy's network (both market and non-market customers) are stored within this system and information is extracted and imported into a separate database - CSI (Customer Service Intelligence). Customer numbers and information is sourced from this database using SQL queries.

The total number of customers for all tariff classes[3] is obtained as a report from the Customer Service Request System (SeRS) as at 30 June of the financial year in question of all National Metering Identifiers (NMIs) with the NMI_STATUS Active, DeEnergised, Greenfield and having a valid TNI_CODE and PRICE_ZONE.

Note: These numbers are based on NMIs which meet connected premise criteria, and do not include connected appliances such as street lights or unmetered supplies associated with these NMIs.

Ergon Energy currently does not maintain a database to capture the entire number of unmetered connections. Street lights that are owned and maintained by third parties and watchman lights, which make up over half of Ergon Energy's unmetered connections parameter reported by Ergon Energy, can be extracted using NetBill and ECORP respectively.

Table 4-31: Template 3 - Outcomes customer service - Customer service

Items	Assumptions and methodology
Timely provision of services	Numbers provided as sourced from the GSL Reporting database. This stores the historical data for completed stages of services orders. The numbers provided directly relate the service order type of Initial Connection – Consumer (Type 1, subtype 1, stage 6). Those not made on agreed date are defined as having a completed date after the target date.
Timely repair of faulty streetlights	The data capture system (FDRSTAT) is used for capturing streetlight outages, recording the time and date of the outage and the time and date of restoration. However, the system is not configured to categorise streetlight outages as a separate category for reporting purposes. Currently, to report this information would be a labour intensive process, which would involve investigating every entry in FDRSTAT for the year and manually record streetlight outages and the associated

[3] ICCs; CACs; EGs; SACs

Items	Assumptions and methodology
	data.
Call Centre Performance (number, unless stated)	Calls to call centre fault line: ▪ Ergon Energy uses Telstra Corporation for its telephony services. Telstra provide reporting capability through an online tool called "Telstra Analyser". This tool allows Ergon Energy employees to analyse call traffic for Ergon Energy inbound services such as 1300 and 13 numbers. It can be used to identify the number of telephone calls made to each telephone number. For the purposes of identifying the number of calls made to the Contact Centre's fault line this tool provides the relevant totals. The tool is able to identify between fault line calls and customer service calls, the latter is excluded for this requirement. The total includes all calls made, irrespective of whether the customer decided to speak with an operator or terminated the call whilst within the IVR system. The call total can then be entered into the parameters listed in Table 3 of the RIN. Calls to fault line not answered within 30 seconds: ▪ Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls. Between 1 July 2014 and 23 May 2015 Ergon Energy used a telephony platform provided by Avaya to route telephone calls. From 23 May 2015 to 30 June 2015 a new system, supplied by Cisco, was brought in to replace the Avaya platform. Both systems provide a mechanism to distribute calls to Ergon Energy operators at the Customer Solutions Centre (CSC) and also enable reporting of call activity. Reportable items for both systems include but are not limited to: ▪ Recording volume of calls received at the call centre: ▪ Recording the length of time between a caller entering the system and the call answered by an operator; and ▪ Recording the length of time between a caller entering the system and the caller abandoning the call. During the period that the Avaya system was in place data was extracted to a data warehouse on a daily basis. This data was then extracted from the warehouse using a system called Brio Intelligence which was used to place data into an excel spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx). Following the installation of the Cisco platform data was extracted directly from the Cisco reporting system, Cisco Unified Intelligence Centre (CUIC). A report is run in this system on a daily basis which provides the number of calls presented to agents with the output saved into a spreadsheet. The main spreadsheet (EECL 1415 APRIN STPIS GOS 14-15.xlsx) then imports the call data via lookup formulas. This data is then used to calculate the total number of calls not answered in 30 seconds by subtracting those calls that were answered in 30 seconds from the total number of calls. This can then be entered into the parameters listed in Table 3 of the RIN. Calls to fault line – average waiting time before call answered:

Items	Assumptions and methodology
	▪ As per the description of the Avaya and Cisco telephony platforms the reporting system s are able to provide details of the length of time between a caller entering the system and the call being answered by an operator. During the period where the Avaya system was in use his information was extracted using a database tool called Brio Intelligence Explorer which took data from the Avaya data stored in the data warehouse and presented it in the form of a pivot table. Following the activation of the Cisco system the reporting system, CUIC, has been used to extract the same type of information. The calculation for average wait time is total number of time waiting divided by total number of calls answered. This can then be entered into the parameters listed in Table 3 of the RIN. Calls Abandoned – percentage: ▪ As per the description of the Avaya and Cisco telephony platforms explains the reporting systems are able to provide details of the number of calls where the caller abandons the call. During the period where Avaya system was in use this information was extracted using a database tool called Brio Intelligence Explorer which took data from the Avaya data stored in the data warehouse and presented it in the form of a pivot table. Following the activation of the Cisco system the reporting system, CUIC, has been used to extract the same type of information. The calculation for percentage of calls abandoned is total number of calls abandoned divided by total number of calls offered. This can then be entered into the parameters listed in Table 3 of the RIN. Call centre – number of overload events: ▪ As explained above Telstra provide reporting capability through an online tool called "Telstra Analyser". This provides the ability to report on the number of events where the telephony system is unable to handle the number of calls being presented to it. This results in those calls being diverted to a message advising that it is not possible to connect their call. This report provides details of the date and times of the events and how many calls were impacted. This can then be entered into the parameters listed in Table 3 of the RIN.
Customer complaints (number)	Ergon Energy has reported Customer Service complaints sourced from the FACTS. FACTS is a database capturing all customer feedback (positive and negative) and enquiries regarding GSLs. For the purposes of reporting customer complaints at the dissemination required in Template 3, Ergon Energy has filtered on all negative complaints and has mapped the RIN categories from the existing FACTS subcategories for the 2014-15 financial year.

Template 5b – Network data – Feeder Reliability

Ergon Energy is required to provide information on Network Feeder Reliability under template 5b.

Ergon Energy understands that the information collected in Non-Financial Template 5b will be used by AER to inform the application of the STPIS to the DNSP in future regulatory periods. The information is also collected to monitor network performance, and may be used in performance reports.

Ergon Energy makes the following general comments in relation to Template 5b Network Data Feeder data.

Table 4-32: Template 5b – Network data feeder reliability

Items	Assumptions and methodology
Annual Feeder Reliability Data	Data supplied in this template is based on actual performance data. Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year. The definitions and methodology used are set out in the AER's Electricity DNSPs, STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period. Unique Feeder IDs are sourced from the FDRSTAT asset data. The interruptions data from FDRSTAT fits the following: ▪ Financial Year 2014-15 (Between 1 July and 30 June) ▪ Include all distribution feeders that experienced completed sustained unplanned and planned interruptions (Interruptions greater that one minute) ▪ Include all active distribution feeders that did not experience any interruptions and that have customers attached to the feeder as at 30 June 2015 ▪ Feeder Classifications: Urban, Short Rural & Long Rural ▪ Customer Minutes ▪ SAIFI calculation - Customer Interrupted DIVIDED BY FDR Average Number of Customers Geographical location is Ergon Energy's legacy supply regions – i.e. FN (Far North), NQ (Northern Queensland), MK (Mackay), CA (Capricornia), WB (Wide Bay), and SW (South West). Distribution Feeders are classified as Urban, Short Rural or Long Rural as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder’s classification the end of the relevant regulatory year. The average number of customers on a feeder is calculated by adding the total of customers connected to the feeder at the beginning of the regulatory year (1 July) and the end of the regulatory year (30 June) and dividing the total by 2. Consistent with the STPIS definition, a customer is defined as a premise having an assigned NMI. Customer numbers are held in the ECORP database. Length of HV overhead distribution lines contains the total length in km of Ergon Energy owned, as constructed overhead conductors for each feeder.

Items	Assumptions and methodology
	Length of HV underground distribution lines contains the total length in km of Ergon Energy owned, as constructed underground conductors for each feeder. It should be noted that the totals of the above two line length data have no bearing on the feeder classifications assigned to the distribution feeders for 2014-15 reliability performance reporting. The line length data set for above is sourced from the Asset Data system and represents the network as it was configured at the end of the relevant regulatory year. The line length data that was utilised to assign feeder classifications is based on network as it was configured at the beginning of the relevant regulatory year. The maximum demand values on a distribution feeder during the regulatory year are provided in MVA. This is provided by Ergon Energy's System Development Group through the Current State Assessment report for distribution feeders. These are the MVA values that were utilised to assign the feeder classifications for the relevant regulatory year. For sixty two (62) of the reported active feeders (with greater than 20 customers connected), the Maximum Demand (MVA) data was not available. Theses feeders are either SR or LR classifications. 52 are classified based on confirmed line length data and the remaining 10 are assigned by default to SR due to a lack of confirmed line length or maximum demand data. Number of unplanned outages records the total number of completed sustained unplanned interruptions that occurred on that distribution feeder during the relevant regulatory year, inclusive of exclusions in accordance with clauses 3.3(a) & (b). Unplanned customer minutes off-supply (including excluded events and MEDs) represents: The total number of unplanned customer minutes due to the completed sustained interruptions that occurred on that distribution feeder during the relevant regulatory year , exclusive of all exclusions in accordance with clauses 3.3(a) & (b). Unplanned customer minutes off-supply (after removing excluded events and MED) represents: The total number of unplanned customer minutes due to the completed sustained interruptions that occurred on that distribution feeder during the relevant regulatory year, exclusive of all exclusions in accordance with clauses 3.3(a) & (b). Unplanned interruptions (SAIFI) (including excluded events and MEDs) represents: SAIFI calculated by the summated feeder customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year , inclusive of all exclusions in accordance with clauses 3.3(a) & (b). Unplanned interruptions (SAIFI) (after removing excluded events and MEDs) represents: SAIFI calculated by the summated feeder customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year , exclusive of all exclusions in accordance with clauses 3.3(a) & (b). Number of Planned outage records the total number of completed sustained planned interruptions that occurred on the distribution feeder during the relevant regulatory year, inclusive of all exclusions in accordance with clauses 3.3(a) & (b). Planned customer minutes off-supply represents the total number of planned customer minutes due to the completed sustained interruptions that occurred on

Items	Assumptions and methodology
	the distribution feeder during the relevant regulatory year, inclusive of all exclusions in accordance with clauses 3.3(a) & (b). Planned interruptions (SAIFI).The planned feeder SAIFI is calculated as follows: ▪ SAIFI calculated by the summated feeder planned customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, inclusive of all exclusions in accordance with clauses 3.3(a) & (b).
Energy not supplied	Energy not supplied (unplanned and planned) has been calculated using data reported for Total unplanned/planned customer minutes off supply (Mins) (Column L and Q) multiplied by the average consumption by feeder (in minutes) sourced from NETBILL. This is in accordance with methodology (c) average consumption of customers on the feeder based on their billing history in the RIN definition for energy not supplied (unplanned). The calculations are based on current connectivity by feeder and not connectivity at the time of the outage. For some feeders that no longer exist or have changed connectivity in the system ECORP the average consumption per minute over all feeders is used. The methodology adopted is irrespective of the time of day the outages occurred.

Template 5d – Outcomes of planned outages

Ergon Energy understands that this information is used to monitor network performance and service outcomes for network customers. It will inform the AER's review of service improvement expenditure in future regulatory control periods.

Ergon Energy makes the following comments with respect to Non-Financial Template 5d.

Table 4-33: Template 5d - Outcomes of planned outages - Planned outages

Items	Assumptions and methodology
SAIDI & SAIFI – after removing excluded events	Data supplied in this template is based on actual performance data. Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year. **Planned SAIDI and SAIFI "Total"** SAIDI and SAIFI for each feeder classification are calculated based the following criteria: ▪ Financial Year 2014-15 (Between 1 July and 30 June) ▪ Completed Planned Sustained Interruptions ▪ Feeder Classifications: Urban, Short Rural & Long Rural ▪ SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers ▪ SAIFI calculation - Customer Interruptions DIVDED BY Average Number of Customers Inclusive of the following exclusions:

Items	Assumptions and methodology
	▪ STPIS MED's ▪ Generation (Exemption clause: 3.3 (a) (2 or 3)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Jurisdictional obligation or right (Exemption clause: 3.3 (a) (7)) **Planned SAIDI and SAIFI for Whole of network "Total"** SAIDI and SAIFI for Whole of Network are calculated based the following criteria: ▪ Financial Year 2014-15 (Between 1 July and 30 June) ▪ Completed Planned Sustained Interruptions ▪ Feeder Classifications: Whole of Network (UR, SR, LR) ▪ SAIDI calculation - Customer Minutes DIVDED BY Average Number of Customers ▪ SAIFI calculation - Customer Interruptions DIVDED BY Average Number of Customers Inclusive of the following exclusions: ▪ STPIS MED's ▪ Generation (Exemption clause: 3.3 (a) (2 or 3)) ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)) ▪ Jurisdictional obligation or right (Exemption clause: 3.3 (a) (7))

5. MOVEMENTS BETWEEN AUDITED STATUTORY ACCOUNTS AND REGULATORY ACCOUNTING STATEMENTS

RIN - Schedule 1 paragraph 1.1 (d)

5.1 Requirement

Schedule 1 paragraph 1.1 (d) of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to provide a Microsoft Excel workbook or other information that explains all movements between the Audited Statutory Accounts and the Regulatory Accounting Statements.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

5.2 Response

Ergon Energy herein provides a Microsoft Excel workbook or other information that explains all movements between the Audited Statutory Accounts and the Regulatory Accounting Statements as an attachment to this Submission.

Refer to Table 21-1: List of Attachments.

6. CAPITALISATION POLICY

RIN - Schedule 1 paragraph 1.1 (e)

6.1 Requirement

Schedule 1 paragraph 1.1 (e) of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to provide the Capitalisation Policy for the Relevant Regulatory Year.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

6.2 Response

Ergon Energy's capitalisation policy is incorporated in its two accounting policies 'Property Plant and Equipment' and 'Intangible Assets' which provide guidance in respect of:

- key criteria for recognition of an asset; and
- clarification of accounting treatment in respect of initial recognition as an asset and subsequent expenditure, including refurbishment costs.

The policy applies to all of Ergon Energy's business units and legal entities.

Ergon Energy herein provides its two accounting policies 'Property Plant and Equipment' and 'Intangible Assets' as attachments to this Submission.

Refer to Table 21-1: List of Attachments.

7. COST ALLOCATION METHOD – STATEMENT OF POLICY

RIN - Schedule 1 paragraph 1.1 (f)

7.1 Requirement

Schedule 1 paragraph 1.1 (f) of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to provide the statement of policy/s for determining the allocation of overheads in accordance with the CAM for the relevant regulatory year.

7.2 Response

Ergon Energy’s Statement of Policy is disclosed below. Consideration will be given to incorporating this into Ergon Energy’s capitalisation policy when it is next updated.

7.2.1 Statement of Policy – Cost Allocation Method

Ergon Energy complies with the CAM, in accordance with Part F - Cost Allocation, Rule 6.15 Cost Allocation, clause 6.15.1 Duty to comply with Cost Allocation Method of the NER.

Where practical, costs are directly attributed to categories of distribution services and unregulated activities.

Shared costs are causally allocated where support services are provided across the Ergon Energy Group and then allocated in proportion to the direct costs incurred by each Line of Business.

8. MATERIAL DIFFERENCES TO DETERMINATION

RIN - Schedule 1 paragraph 1.2, 1.3

8.1 Requirement

Schedule 1 paragraph 1.2 (a)-(d) of the AER's Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to identify for each of the following items, the material difference between the amounts reported in the Regulatory Accounting Statements and the amounts provided for in the AER FDD for the relevant regulatory year:

- total actual revenue and total forecast revenue;
- total actual Opex and total forecast Opex;
- total actual maintenance expenditure and total forecast maintenance expenditure; and
- total actual Capex and total forecast Capex.

Schedule 1 paragraph 1.3 of the Notice requires Ergon Energy to explain the reasons for any underlying operational activities or drivers that caused each material difference identified in the response to paragraph 1.2.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

8.2 Response

Please refer to the following explanations for material differences in the Regulatory Accounting Statements in the following Templates:

- Operating Expenditure – Template 10 (Opex), Table 2: Explanation of material difference. See also Table 4-15: Template 10 – Network Operating costs - Explanation of material difference);
- Maintenance Expenditure – Template 8 (Maintenance), Table 2: Explanation of material differences (see also Table 4-11: Template 8 – Network Maintenance – Explanation of Material Differences); and
- Capital Expenditure – Template 5 (Capex), Table 2: Explanation of material differences (see also Table 4-4: Template 5 - Capex - Explanation of Material Differences).

In addition refer to supplementary templates prepared for the purposes of providing explanations in material variances between total actual revenue and total forecast revenue.

Refer to Table 21-1: List of Attachments.

9. CLASSIFICATION OF DISTRIBUTION SERVICES

RIN - Schedule 1 paragraph 1.4

9.1 Requirement

In respect of the classification of services, Schedule 1 paragraph 1.4 of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to explain the procedures and processes used by Ergon Energy to ensure that the distribution services have been classified as determined in the AER FDD.

9.2 Response

In the majority of instances, the classification of Ergon Energy services happens automatically as customers and retailers generally select the service they require. A listing and description of Ergon Energy services by service order type (with the associated product codes and prices) is provided in the "Price List for ACS" which is published on Ergon Energy's website. The Price List is developed in accordance with the classification of services (CoS) and Ergon Energy's AER-approved Pricing Proposal.

Customers can make requests for services through their retailer (if in the market), or they can contact Ergon Energy's National Contact Centre (NCC). The NCC has a range of scripts and an Online Help System which informs operators about what steps should be taken to correctly identify a service and process a customer's request. A schedule of rates is also readily accessible to operators to determine on what basis fees will apply for the customer's requested service (no charge, standard fee, customer-specific quote required etc.).

Tier 2 retailers make requests for Ergon Energy services through market systems in accordance with the National B2B Procedures. Ergon Energy's Service Transaction Centre manages requests from market retailers, and has well established procedures in place to ensure services are correctly identified and processed appropriately through market systems.

Specialist business units within Ergon Energy have also been established to handle more complex service requests, and calculate prices for services requiring quotations (for example – new connections to the network, supply enhancements, rearrangement of network assets, design and construction of connection assets and street lights etc.). These business units have a range of procedures, work instructions and reference materials to ensure the service is correctly classified and appropriately priced. For example, in the case of large customer connections, Ergon Energy's Major Customer Connection Group has a manual to assist them to determine the classification of assets, and which components of a project will be required to be funded under the SCS revenue cap, and which components will be funded through ACS charges levied on customers.

Staff requiring further guidance about a service classification, can request specialist regulatory advice from Ergon Energy's Regulatory Affairs Group.

Customers and retailers also have avenues available to them to request a review of a service classification decision through Ergon Energy's Tariff Class Assignment and Re-assignment Procedures. These procedures are publicly available in Ergon Energy's "Information Guide for SCS Pricing", "Information Guide for ACS Pricing" and "Price List for ACS". The procedures are also issued to retailers through the 'Retailers Handbook'.

10. ARRANGEMENTS FOR NEGOTIATED SERVICES

RIN - Schedule 1 paragraph 1.5

10.1 Requirement

Schedule 1 paragraph 1.5 of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to explain the procedures and processes used by Ergon Energy to ensure that the negotiated distribution service criteria, as set out in the AER FDD, have been applied.

10.2 Response

Ergon Energy notes that Schedule 1 paragraph 1.5 of the RIN is not applicable to Ergon Energy during the current regulatory control period.

In its submission to the AER on the Framework and Approach Stage 1 consultation, Ergon Energy did not propose in its classification of services proposal that any of its Distribution Services be classified as Negotiated Distribution Services. As a result, Ergon Energy does not have a Negotiating Framework, nor is the Negotiated Distribution Service Criteria that the AER released on 17 July 2009 relevant.

In accordance with the AER's Queensland Distribution Determination, 2010-11 to 2014-15, Final Decision (May 2009), which accepted the list of services that Ergon Energy identified for each category of Distribution Services, Ergon Energy has no Negotiated Distribution Services.

11. NEGATIVE CHANGE EVENTS

RIN - Schedule 1 paragraph 1.6

11.1 Requirement

Schedule 1 paragraph 1.6 of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to discuss the process it has in place to identify negative change events under NER clause 6.6.1(f) and the threshold of materiality applied by Ergon Energy to these events.

In accordance with Appendix B to the Notice, the AER requires Ergon Energy to verify, by way of a statutory declaration the information provided in response to Schedule 1 paragraph 1.6.

11.2 Response

11.2.1 Process for identifying Negative Change Events

Ergon Energy's process for identifying negative change events involves the following actions:

- Recognising the identification and reporting of negative change events as an additional regulatory obligation within the business. In particular, Regulatory Affairs' work plan has included this as an obligation;
- The identification and reporting of negative change events is coordinated by Ergon Energy's Regulatory Affairs group. However other departments are involved as required;
- Regulatory Affairs is responsible for the identification and communication of the following negative change events: Regulatory Change; Service Standard; and Feed-in Tariff;
- Finance is responsible for the identification of possible negative change events resulting from Tax Changes;
- The relevant departments are responsible for reviewing relevant material, identification of possible negative change events, reporting of events to Regulatory Affairs (as coordinator) and ensuring the timely and accurate documentation of the process;
- The relevant departments are to identify and record the documents/web sites and any other resources intended to be reviewed in the search for negative change events. For example, Queensland government media statements, Commonwealth government media statements, AER publications/statements, financial reporting documents (or other relevant documents providing updates to tax policy);
- A communication protocol is to be established between the relevant departments and Regulatory Affairs and within the Regulatory Affairs department to ensure that the identification process is being actively conducted;
- The responsible person within Regulatory Affairs is required to notify the Regulatory Affairs Manager immediately where a possible negative change event is identified by any department;
- The Regulatory Affairs Manager is to confirm that the event meets the criteria of a negative change event;

- Once confirmed, Regulatory Affairs is to be responsible for the determination of estimated costs associated with the event in conjunction with relevant internal departments;
- In doing so, it is important to consider the distinction between under-expenditure resulting from deliberate business decisions or forecasting error and that resulting from a negative change event. In particular, the distinction between controllable and uncontrollable costs is critical. By nature, a negative change event must be an exogenous event beyond the control of Ergon Energy. By definition, all management decisions by Ergon Energy regarding the investment in and operation of its network that subsequently result in cost savings cannot be treated as a negative pass-through event; and
- Regulatory Affairs is responsible for coordinating the preparation of pass-through applications and providing it to the AER as per requirements.

11.2.2 Materiality Threshold Applicable to Negative Pass through Events

The AER's Determination for Ergon Energy indicates that the AER will apply a materiality threshold to specific nominated events set to the administrative costs of assessing an application[4]. However, for general nominated events the AER Determination did impose a materiality threshold of 1% of the smoothed revenue allowance specified in the Distribution Determination for each of the years of the regulatory control period in which the costs are incurred[5].

[4] AER (2009), p 299. Note: while this decision was made in the context of the AER's Draft Determination, no changes were proposed in the Distribution Determination (Final Decision).

[5] Ibid, p 312

12. COST ALLOCATION TO THE REGULATED DISTRIBUTION BUSINESS

RIN - Schedule 1 paragraph 2.1-2.3

12.1 Requirement

Schedule 1 paragraph 1.6 of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to discuss the process it has in place to identify negative change events under NER clause 6.6.1(f) and the threshold of materiality applied by Ergon Energy to these events.

In accordance with Appendix B to the Notice, the AER requires Ergon Energy to verify, by way of a statutory declaration the information provided in response to Schedule 1 paragraph 1.6. In respect of cost allocation to the regulated distribution business, Ergon Energy is required to comply with Schedule 1 paragraph 2.1 -2.3 of the Notice, as detailed below.

2.1 Identify each item in the Regulatory Accounting Statement that is:

(a) not allocated on a directly attributable basis but is allocated on a causation basis to the *distribution business*; and

(b) not allocated on a directly attributable basis and cannot be allocated on a causation basis to the *distribution business*.

2.2 For each item identified in the response to paragraph 2.1 (a):

(a) state the amount of the item that has been allocated;

(b) explain the method of allocation and reasons for choosing that method; and

(c) state the numeric amount of the allocator(s) used.

2.3 For each item identified in the response to paragraph 2.1(b):

(a) state its amount;

(b) state whether it was material;

(c) explain the method of allocation and reasons for choosing that method; and

(d) explain the reason(s) why it cannot be allocated on a causation basis.

12.2 Response

Ergon Energy complies with its CAM that has been approved by the AER.

Direct costs are directly attributed to the *distribution* or unregulated businesses.

Shared costs are causally allocated where support services are provided across the Ergon Energy Group. The costs which are causally allocated are disclosed in the Appendix B Regulatory Accounting Statements in Template 15. The method of application is disclosed in Ergon Energy's CAM.

Upon final reconciliation of the shared costs allocated through the overhead allocation process at the end of the regulatory year, it was determined that an amount of $21.4m had been over-applied. In accordance with

Ergon Energy's CAM, this amount was determined to be not material and has not been directly attributed or causally allocated. Ergon Energy's CAM requires such amounts to be allocated to the distribution business.

Ergon Energy has applied further allocations throughout the Regulatory Accounting Statements to enable completion of other Income Statement items across the *distribution* and unregulated businesses. The basis for each of these allocations is detailed in the Reasons, Assumptions and Methodology section of this document.

13. COST ALLOCATION TO SERVICE SEGMENTS

RIN - Schedule 1 paragraph 3.1-3.3

13.1 Requirement

Ergon Energy is required to comply with Schedule 1 paragraph 3.1 -3.3 of the Notice, as amended by the AER on 6 August 2014, as detailed below.

3.1 Identify each item in the Regulatory Accounting Statements that is:

(a) not allocated on a directly attributable basis but is allocated on a causation basis from the distribution business to a service segment; and

(b) not allocated on a directly attributable basis and cannot be allocated on a causation basis from the distribution business to a service segment.

3.2 For each item identified in the response to paragraph 3.1(a):

(c) state the amount of the item that has been allocated;

(d) explain the method of allocation and reasons for choosing that method; and

(a) state the numeric amount of the allocator(s) used.

3.3 For each item identified in the response to paragraph3.1(b):

(e) state its amount;

(f) state whether it was Material;

(g) explain the method of allocation and reasons for choosing that method; and

(a) explain the reason(s) why it cannot be allocated on a causation basis.

Further it should be noted that service segment refers to SCS, ACS, negotiated services and unregulated services.

13.2 Response

Ergon Energy complies with its CAM approved by the AER.

Direct costs are directly attributed to the categories of Distribution Services and unregulated activities.

Shared costs are causally allocated where support services are provided across the Ergon Energy Group. The costs which are causally allocated are disclosed in the Appendix B Regulatory Accounting Statements in Template 15. The method of application is disclosed in Ergon Energy's CAM.

Upon final reconciliation of the shared costs allocated through the overhead allocation process at the end of the regulatory year, it was determined that an amount of $21.4m had been over-applied. In accordance with Ergon Energy's CAM, this amount was determined to be not material and has not been directly attributed or causally allocated. Ergon Energy's CAM requires such amounts to be allocated to the SCS.

Ergon Energy has applied further allocations throughout the Regulatory Accounting Statements to enable completion of other Income Statement items across the categories of Distribution Services. The bases for each of these allocations are detailed in the Reasons, Assumptions and Methodology section of this document.

14. RELATED PARTY TRANSACTIONS

RIN - Schedule 1 paragraph 4.1-4.3

14.1 Requirement

Schedule 1 paragraph 4.1-4.2 of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to identify each Related Party with which a transaction has been conducted. The Notice also requires Ergon Energy to identify each transaction relating to the provision of SCS, ACS or negotiated distribution services between Ergon Energy and a Related Party, where the transaction amount is greater than five per cent of the relevant total expenditure or revenue category. Relevant categories are SCS revenues, ACS revenues; negotiated distribution services revenues, SCS Capex, ACS Capex, SCS operations expenditure, SCS maintenance expenditure, ACS operations expenditure, ACS maintenance expenditure, negotiated distribution services expenditure. Further paragraph 4.3 of Schedule 1 of the Notice requires that for each transaction in the response on paragraph 4.2;

- state the name of the Related Party;
- identify any other parties involved;
- explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related Party;
- state the actual costs incurred by the Related Party in providing good(s) or services(s), not including any profit margin or management fee incurred by Ergon Energy;
- explain how the actual costs of the good(s) or service(s) incurred was determined;
- identify the actual costs of the good(s) or service(s) in the Regulatory Accounting Statements, including the Asset category, Maintenance Cost category or Operating Cost category to which the actual cost(s) is allocated to; and
- explain the basis upon which the actual costs of the good(s) or service(s) was or were allocated, as identified in the response to paragraph (f), and state the amount of any allocator applied.

14.2 Response

Ergon Energy's related parties are Ergon Energy Telecommunications Pty Ltd which provides telecommunication services and SPARQ Solutions Pty Ltd which provides information technology services. The cost of goods and services provided by these related parties was determined from the invoices issued upon Ergon Energy and were $117.4M for SPARQ Solutions Pty Ltd and $2.7M for Ergon Energy Telecommunications Pty Ltd.

Allocation between entities is established by the methodology as set out in the CAM. Ergon Energy Telecommunications Pty Ltd is treated entirely as an Opex and is spread between SCS, ACS and non-regulated activities according to the overhead allocation methodology as set out in the CAM. The costs from SPARQ Solutions Pty Ltd is split between capital and Opex using the overhead allocation methodology as set out in the CAM these amount are then split between SCS, ACS and non-regulated again using the CAM methodology.

No other parties are involved.

15. EFFICIENCY BENEFIT SHARING SCHEME

RIN - Schedule 1 paragraph 5.1-5.2

15.1 Requirement

With respect to the Efficiency Benefit Sharing Scheme, Schedule 1 paragraph 5.1 of the Notice as amended by the AER on 6 August 2014, requires Ergon Energy to identify all changes between the Capitalisation Policy for the relevant regulatory year and the previous regulatory year. Further, for each change identified in the response to paragraph 5.1, paragraph 5.2 requires Ergon Energy to:

- state, if any, the financial impact of the change;
- state the reasons for the change;
- explain the effect of the change (excluding changes in accounting policies) if any, on:
  - forecast operating and maintenance expenditure incurred for the Relevant Regulatory Year;
  - forecast Capex incurred for the Relevant Regulatory Year;
  - actual operating and Maintenance Expenditure incurred for the Relevant Regulatory Year;
  - actual Capex incurred for the Relevant Regulatory Year; and
- explain the estimated effect of the change, if any, for the previous regulatory year on:
  - actual operating and maintenance expenditure incurred; and
  - actual Capex incurred.

15.2 Response

No Capitalisation Policy changes occurred during the 2014-15 year.

16. DEMAND MANAGEMENT INCENTIVE SCHEME

RIN - Schedule 1 paragraph 6.1

16.1 Requirement

In respect of the DMIA Schedule 1 paragraph 6.1 of the Notice as amended by the AER on 6 August 2014, requires Ergon Energy to:

(a) provide an explanation of each DM project or program for which approval is sought;

(b) explain, for each DM project or program identified in the response to paragraph 6.1(a), how it complies with the DM Innovation Allowance criteria detailed at section 3.1.3 of the DMIS, with particular reference to:

- (i) the nature and scope of each demand management project or program;
- (ii) the aims and expectations of each demand management project or program;
- (iii) the process by which each demand management project or program was selected, including the business case for the demand management project and consideration of any alternatives;
- (iv) how each demand management project or program was/is to be implemented;
- (v) the implementation costs of the demand management project or program;
- (vi) any identifiable benefits that have arisen from the demand management project or program, including any off peak or peak demand reductions;

(c) provide an overview of developments in relation to the demand management projects or programs completed in previous years, and any results to date;

(d) state whether the costs associated with each demand management project or program identified in the response to paragraph 6.1(a) are:

- (i) not recoverable under any other jurisdictional incentive scheme;
- (ii) not recoverable under any other Commonwealth or State Government scheme;
- (iii) not included as part of:
  - (1) the forecast Capex or the forecast Opex; or
  - (2) any other incentive scheme applied by the 2010–15 Distribution Determination; and

(e) provide the total amount of the Demand Management Innovation Allowance spent in the previous regulatory year and how this amount has been calculated.

It should be noted that information provide in response to paragraph 6 of Schedule 1 to this Notice will constitute the provision of an annual report for the purpose of paragraph 3.1.4.1 of the AER, *Demand Management Incentive Scheme for Energex, Ergon Energy and ETSA Utilities 2010/15*, October 2008.

16.2 Response

Ergon Energy's 14-15 Demand Management Innovation Allowance Report is attached.

Refer to Table 21-1: List of Attachments.

17. STPIS PERFORMANCE MEASURES

RIN - Schedule 1 paragraph 7.1

17.1 Requirement

Schedule 1 paragraph 7.1 of the Notice, as amended by the AER on 6 August 2014, requires Ergon Energy to explain all Material differences between the target performance measure specified in the STPIS and actual performance reported in the response to paragraph 1.1(b) of Schedule 1.

17.2 Response

17.2.1 Reliability Parameters

Ergon Energy unplanned reliability performance for 2014-15 was favourable to 4 out of 6 STPIS targets. SAIDI and SAIFI for the Long Rural category were the only measures that did not outperform the STPIS targets for 2014-15.

For 2013-14 unplanned reliability performance outperformed all six STPIS reliability targets due to an exceptionally mild summer storm season. Weather conditions across 2014-15 however were more unstable and as a result, for 5 of 6 reliability measures, performance this year was unfavourable compared to the previous year. The Urban category SAIDI reports a margin of 7.0%, Short Rural category SAIDI and SAIFI reports a margin of 18.3% and 12.8% respectively and the Long Rural category SAIDI and SAIFI report a margin of 35.5% and 11.1% respectively. The Urban category SAIFI measure reports an improvement on the previous year of 9.8%.

Achieving performance in the rural network segments that is consistently favourable to the STPIS targets is a challenge for Ergon Energy. The annual variability in supply interruptions occurring in the rural areas is influenced significantly by the severity of weather events and in general by longer term weather patterns. The duration of the supply interruption events in these areas is extended (by comparison to the urban areas) because of the vast geographical spread of assets serviced by the regional depots and the interruption exposure resulting from the predominantly radial arrangement of the supply chain in this network type.

Weather related interruption events heavily influenced Ergon Energy's reliability performance in the Long Rural network in 2014-15. The 2014-15 summer storm season was exceptionally severe and as a direct result, the reliability of supply performance in the Long Rural category exceeded the STPIS targets for both duration (SAIDI) and frequency (SAIFI). For the year, 3 Major Event Days (MEDs) were identified associated with severe weather events. The exclusion of the interruptions occurring on MEDs provided an effective mechanism in managing performance variability in the Urban and Short Rural categories, these exclusions however had limited influence on the Long Rural category performance reported this year.

Long Rural distribution feeders were subjected to a significantly higher number of lightning strikes this year compared to the past 5 storm seasons; with 70% more strikes in close proximity to Long Rural feeders in 2014-15 than the historical average. Compared to recent years, between December 2014 and March 2015 Long Rural feeder type experienced:

- 66% more unplanned supply interruption events,
- 57% more customer interruptions; and

- 65% more minutes of interrupted supply to customers.

The variability in short term patterns of weather continues to demonstrate a strong relationship to the reliability of supply outcomes for the Ergon Energy customers in rural and remote Queensland.

Ergon Energy continues to monitor, assess, analyse and undertake the necessary remedial action to ensure underlying reliability performance levels are maintained and only improved where it is prudent to do so.

17.2.2 Customer Service Parameters

Ergon Energy's Telephone Answering actual performance was favourable when compared to the target of 77.3% with a result of 80.5% for 2014-15. As has been the case in recent years, service levels were comfortably maintained through the quieter non-storm season months with results above target for the first four and last five months of the financial year. Within these seven months there were no more than seven days where grade of service target was not met in any of the given months.

The period between November and January provided a far more challenging operational environment however. Storm activity had considerable impacts in November with almost 20,000 more calls handled than had been received in the previous month. This included a period of six days where more than a third of the month's calls were received, with service level not met through this period. Further pressure was applied in December however which, in terms of call volumes, was the busiest month for two years. There were very active storm cells in the far north and south of the state which drove these customer contacts. Whilst an Major Event Day (MED) was declared on 6th December the calls received between the 7 and 13 of December made up almost half of the total number of included calls for the month. This resulted in grade of service not being met in all but one of these days. Storm activity in the latter part of January also resulted in less favourable service level outcomes. This included additional calls being handled as a result of Powerlink outages affecting 187,342 customers on 16 and 21 of January 2015.

Whilst service level was achieved in the month of February, thanks in the main to very little storm activity for the majority of the month, the most significant weather event of the year did occur. Tropical cyclone Marcia crossed the coast in Central Queensland on 20 February 2015, causing considerable damage to the communities of Rockhampton, Yeppoon and surrounding areas. An MED was declared for 20 February 2015, although around half of the months calls were received between the 21 and 28 of February 2015. Despite this the organisations disaster response plan was activated meaning front line phone staff numbers were maximised. This included the rostering of staff from other areas of the business and the activation of the Disaster Assistance Programme (DAP) with Energex providing access to five of their staff to assist. As a result service level was under target on only a single day during the cyclone response period and there were only four days in the whole month where target was not achieved.

There was another cyclone for the season, Tropical Cyclone Nathan, but this had minimal impacts on the contact centre. This system crossed the coast in late March around the relatively unpopulated area of Cape Flattery and caused minimal impacts to Ergon Energy assets.

In summarising the year it would be reasonable to say that the most operationally challenging impacts came from routine storm activity rather than a significant disaster event like a flood or cyclone, as has often been the case in recent years. Total call volumes for the year were higher than in the previous two years with an additional 21,168 calls (after exclusions) presented to the contact centre compared to last year. This required a consistent focus on delivering effective staff rostering during the storm season to achieve the positive result that was ultimately achieved for the year.

18. GROUP CORPORATE AND ORGANISATIONAL STRUCTURES

RIN - Schedule 1 paragraph 10.1

18.1 Requirement

In respect of Charts Schedule 1 paragraph 8.1 of the Notice as amended by the AER on 6 August 2014, requires Ergon Energy to provide charts that set out the group corporate structure of which Ergon Energy is a part and the organisational structure for Ergon Energy.

18.2 Response

Figure 1 illustrates Ergon Energy's Group Structure. The Ergon Energy Group comprises a series of companies involved in the purchase, distribution and sale of electricity in Queensland, both within and outside the NEM.

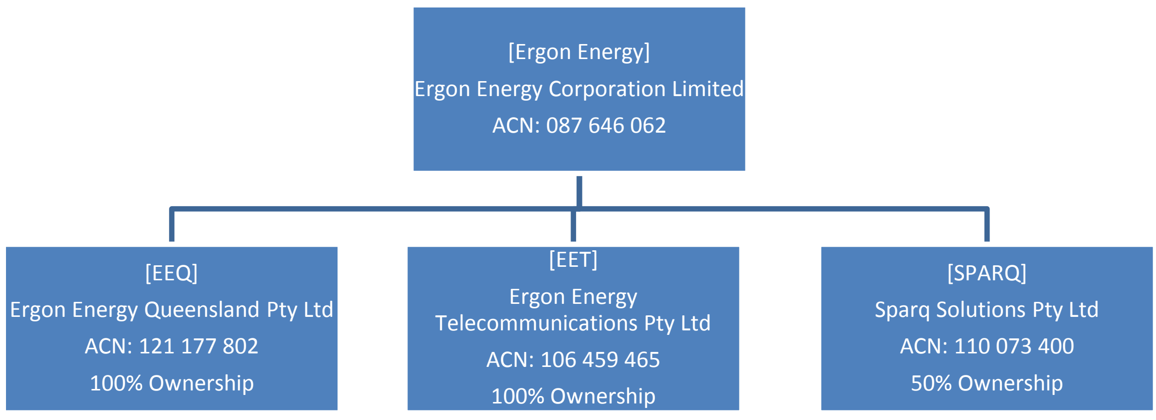

Figure 1: Ergon Energy Group Structure

Figure 2 illustrates Ergon Energy's organisation structure. In particular, it shows the relationship between the Board of Directors, the Executive Management Team, and the various Business Units within Ergon Energy.

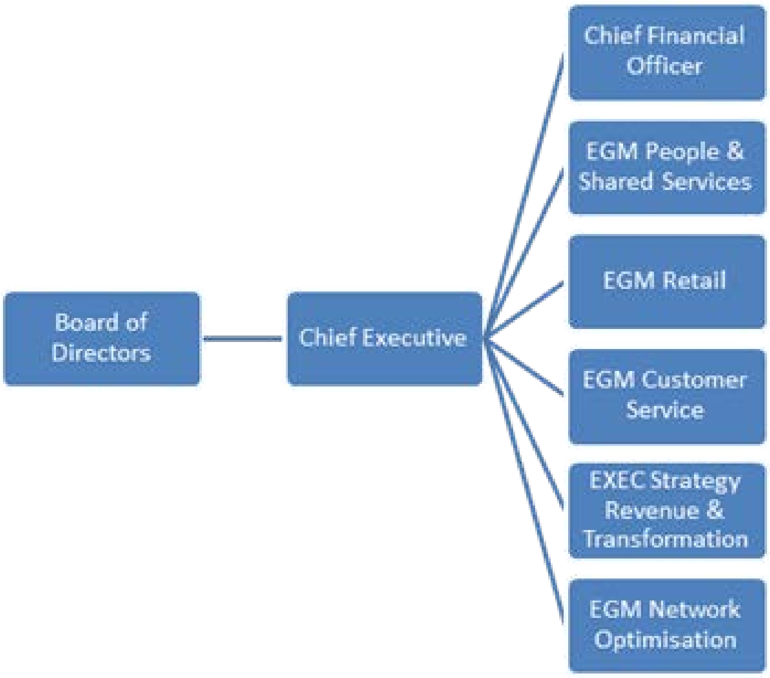

Figure 2: Ergon Energy Organisational Chart

19. AUDIT REPORTS

RIN - Schedule 1 paragraph 9.1, Appendix E

19.1 Requirement

Schedule 1 paragraph 11.1 of the Notice as amended by the AER on 6 August 2014, requires Ergon Energy to provide the results of the audit as specified in Appendix E to the Notice, namely the audit report/s in the form of:

- a Special Purpose Financial Report in accordance with the requirements set out at Appendix E of the Notice; and
- Audit Report/s (for Non-Financial Regulatory Templates information) in accordance with the requirements set out at Appendix E of the Notice.

19.2 Response

Ergon Energy notes the following auditors were appointed to audit its 2014-15 Annual Performance RIN and associated templates (as appropriate):

- Auditor-General of Queensland to audit the Regulatory Accounting Statements in accordance with the Audit scope at Appendix E paragraph 1.1(a) of the RIN;
- Parsons Brinckerhoff (PB) to audit the Non-Financial Regulatory Templates in accordance with the Audit scope at Appendix E paragraph 1.1(b) of the RIN.

As required under Schedule 1 paragraph 11.1 of the Notice, Ergon Energy provides the following results of the abovementioned audits as attachments to this submission, namely the Audit Report(s) by Queensland Audit Office and Parsons Brinckerhoff -:

- Audit Opinion (Financial Information Regulatory Accounting Statements) – Actual;
- Audit Report (Non-Financial Regulatory Templates) – Actual.

Refer to Table 21-1: List of Attachments.

20. STATUTORY DECLARATION

RIN - Appendix D

20.1 Requirement

The AER requires Ergon Energy to verify specified information, by way of a statutory declaration by an Officer of the Company in accordance with Appendix D to the Notice. A pro forma Statutory Declaration was provided by the AER in this regard.

20.2 Response

Ergon Energy herein provides a Statutory Declaration signed by the Chief Executive of Ergon Energy Corporation Limited, as an attachment to this submission.

Refer to Table 21-1: List of Attachments.

21. APPENDIX A – LIST OF ATTACHMENTS

Unless otherwise identified as confidential information, the below attachments are for Public release.

Table 21-1: List of Attachments

Title	Attachment
EECL 1415 APRIN_FRAS	Ergon Energy's 2014-15 Regulatory Accounting Statements, for the regulatory year ended 30 June 2014
EECL 1415 APRIN_NFRT	Ergon Energy's 2014-15 Non-Financial Regulatory Templates, for the regulatory year ended 30 June 2014
EECL 1415 APRIN_S1 RECON	Reconciliation of Audited Statutory Accounts and Regulatory Accounting Statements
EECL 1415 APRIN_S1 RSUP	Supplementary Templates; Explanations for material variances (Revenues)
EECL 1415 APRIN_S1 POL EECL 1415 APRIN_S1 IA	Capitalisation Policies; Property, plant and equipment; and Intangible Assets.
EECL 1415 APRIN_S1 DMIA	Ergon Energy's 2014-15 Demand Management Innovation Allowance - Annual Report to the AER, for the regulatory year ended 30 June 2015.
EECL 1415 APRIN_PB NF(A)	Parsons Brinckerhoff - Audit Report (Non-Financial Regulatory Templates)
EECL 1415 APRIN_QAO F(A)	Queensland Audit Office - Audit Opinion (Regulatory Accounting Statements)
EECL 1415 APRIN_SDEC	Ergon Energy Corporation Limited, Chief Executive - Statutory Declaration

Customer Service
13 10 46
7.00am – 6.30pm, Monday to Friday

Faults Only
13 22 96
24 hours a day, 7 days a week

Life-Threatening Emergencies Only
Triple zero (000) or 13 16 70
24 hours a day, 7 days a week

Ergon Energy Corporation Limited ABN 50 087 646 062
Ergon Energy Queensland Pty Ltd ABN 11 121 177 802

ergon.com.au