# ERGON ENERGY

# Reset Regulatory Information Notice – Schedule 1 Response

Final Submission

1 July 2015 to 30 June 2020

31 October 2014

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# Introduction

## Relationship between Ergon Energy’s Schedule 1 Response and Regulatory Proposal

Much of the information required in response to Schedule 1 of the Reset Regulatory Information Notice (RIN) is also required or permitted by the National Electricity Rules (Rules) to be contained in Ergon Energy's Regulatory Proposal.

To streamline the volume of information provided and to support the assessment by the Australian Energy Regulator (AER) on a comprehensive and consistent basis our Schedule 1 Response refers the AER to information contained in particular sections of the Regulatory Proposal and attachments to the Regulatory Proposal (where appropriate). Where this approach has been applied, we have included a cross-reference in our Schedule 1 Response which identifies the relevant document number, name and section (where applicable) that addresses the AER’s specific query.

In considering our Schedule 1 Response therefore, it is critical that regard is had to the related information contained in both the Regulatory Proposal and its attachments.

## Benchmarking and Comparative Analysis

In some sections, the RIN requests Ergon Energy to make comparisons between itself and other Distribution Network Service Providers (DNSPs). In those areas we have sought to address the RIN requirement as fully as possible. However, it is important to note that Ergon Energy does not have a complete understanding of the conditions that affect the operation of, or expenditure on, other distribution networks, which necessarily limits Ergon Energy's ability to undertake such comparisons. Limitations on the utility of existing benchmarking tools and models also affect our ability to make comparisons that allow for all relevant variables, drivers and other factors that influence the operation of different network businesses.

Further details of these issues and the challenges that they present when seeking to undertake comparative analysis can be found in the following Regulatory Proposal attachments:

- 0A.00.01How Ergon Energy Compares
- 0A.01.02 Journey to the Best Possible Price
- 0A.01.04 Engagement Program
- 0A.02.01 Ergon Benchmarking
- 0A.02.03 Huegin – Ergon Energy Category Analysis Benchmarks
- 0A.02.04 Huegin – 2012 Distribution Benchmark Summary
- 06.01.05 Meeting the Rule Requirements
- 07.00.01 Asset Renewal Forecast Expenditure Summary
- 07.00.02 Forecast Expenditure Summary Corporation Initiated Augmentation.

## Expenditure Category Level Information

Ergon Energy has produced a suite of summary documents in support of each expenditure category. These documents provide a description of how expenditure forecasts have been developed or how components of the Regulatory Proposal have been developed and applied, and are provided as attachments to the relevant sections of our Regulatory Proposal.

Each expenditure summary document follows a broadly similar format and generally contains the following quantitative and qualitative details:

- Current period outcomes, including an explanation of variances between our current period expenditure, our forecasts and the AER's determination for the 2010-15 regulatory control period
- Expenditure forecast for the 2015-20 regulatory control period, including an explanation of how we prepared the forecast and why we consider that our forecasting methodology is reasonable
- Appropriate breakdowns by expenditure subcategory and RIN category
- A comparison of our forecasts to the historical trend with explanations of deviations from the trend
- Key inputs and assumptions and why we consider that these key inputs and assumptions are reasonable
- A demonstration that forecasts and proposed expenditure programmes are based on sound justifications that are efficiency-based, linked to economic conditions, local demand factors and the long term interests of consumers
- The link between prudent and efficient process for investment and our forecasting methodologies
- A demonstration that the expenditure forecasts enable maintenance of acceptable risk levels in line with the National Electricity Objective (NEO) and other requirements
- The outcomes that we will deliver to our customers and how our customers' feedback has been considered
- Any relevant benchmarking
- The application of the AER's predictive models to assess our forecasts and any limitations or flaws associated with these predictive models.

Further details and analysis, by expenditure category, can be found in the following summary documents:

- 05.01.01 Public Lighting Summary
- 05.03.01 Default Metering Services Summary
- 06.01.01 Opex Forecast Summary
- 06.01.02 System Related Opex Expenditure Summary
- 07.00.01 Asset Renewal Forecast Expenditure Summary
- 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary
- 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary
- 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary
- 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary
- 07.00.06 Fleet Expenditure Forecast Summary
- 07.00.07 ICT Expenditure Forecast Summary
- 07.00.08 Property Expenditure Forecast Summary
- 07.00.09 Unit Cost Methodologies Summary.

# 1. PROVIDE INFORMATION

**1.1. Provide the information required in each regulatory template in the Microsoft Excel Workbooks attached at Appendix A completed in accordance with:**

**(a) this Notice;**

**(b) the instructions in the Microsoft Excel Workbooks attached at Appendix A;**

**(c) the Principles and Requirements in Appendix E; and**

**(d) the service classifications set out in the framework and approach paper (this requirement does not relate to Ergon Energy's regulatory asset base values in the current regulatory control period or the previous regulatory control period).**

Ergon Energy has provided the information required in each regulatory template in the Microsoft Excel Workbooks attached at Appendix A in accordance with the requirements outlined above, subject to any variations agreed with the Australian Energy Regulatory (AER) or otherwise disclosed in Ergon Energy Reset Regulatory Information Notice, Final Submission 1 July 2015 – 30 June 2020, dated 31 October 2014.

**1.2. For information other than Forecast Information, provide in accordance with this Notice and the Principles and Requirements in Appendix E, a Basis of preparation document(s) demonstrating Ergon Energy has complied with this Notice in respect of the information inserted into each regulatory template in the Microsoft Excel Workbooks attached at Appendix A.**

Ergon Energy has provided Basis of Preparation documents in accordance with the above instructions. Refer to 0C.03 Reset RIN Basis of Preparation.

**1.3. Provide the cost allocation method used by Ergon Energy to allocate costs in accordance with rule 6.15 of the NER between distribution services.**

Ergon Energy's Cost Allocation Method has been provided and approved by the AER in its decision dated 15 August 2014. Refer to http://www.aer.gov.au/node/27108.

**1.4. Provide for the purposes of the preparation of the regulatory proposal:**

**(a) a regulatory template that references each response to a paragraph in this Schedule 1, where it is provided in or as part of the regulatory proposal.**

Ergon Energy has provided regulatory templates in accordance with the above instructions provided at 0C.02 Reset RIN Templates.

**1.5. Capital and operating expenditure forecasts provided in the regulatory templates must be reconciled to the ex-ante capital and operating allowances in Post-Tax Revenue Model for the forthcoming regulatory control period.**

Ergon Energy has provided capital and operating expenditure forecasts in the regulatory templates which reconcile to the ex-ante capital and operating allowances in the Post Tax Revenue Model for the forthcoming regulatory control period.

### Regulatory Template Table 2.1.1 – Standard Control Services Capex

This table reconciles to the 03.01.04 SCPTRM Data Model AER May 2014 Version as follows:

- The sum of the “Total Gross Capex (includes capital contributions (capcons))” values for 2015-16 to 2019-20 inclusive in the Table 2.1.1
- *less* the sum of the “Forecast Asset Disposal – as incurred” values for 2015-16 to 2019-20 inclusive in 03.01.04 SCPTRM Data Model AER May 2014 Version
- *plus* Equity raising costs in 03.01.04 SCPTRM Data Model AER May 2014 Version (for 2015-16 only)
- *less* the sum of the “capcons” values for 2015-16 to 2019-20 inclusive in Table 2.1.1
- *equals* the sum of the “Forecast Net Capital Expenditure – As Incurred” in the Input tab of the 03.01.04 SCPTRM Data Model AER May 2014 Version for 2015-16 to 2019-20 inclusive.

### Regulatory Template Table 2.16.2 – Standard Control Services Opex

This table reconciles to the 03.01.04 SCPTRM Data Model AER May 2014 Version as follows:

- The sum of the “Total Opex” values for 2015-16 to 2019-20 inclusive in the Table 2.1.1
- *less* the sum of the “Non-Network” values for 2015 16 to 2019-20 inclusive in Table 2.1.1
- *equals* the sum of the “Total” opex in the Input tab of the 03.01.04 SCPTRM Data Model AER May 2014 Version for 2015-16 to 2019-20 inclusive. This includes debt raising costs.

The opex values for 2014-15 are not contained within a PTRM for the regulatory control period 2015-20 and hence no reconciliation has been performed on these values.

### Regulatory Template Table 2.1.3 – Alternative Control Services Capex

The following elements of this table reconcile to the 05.02.03 PLPTRM Data Model with Prices as follows:

- The “Forecast Net Capital Expenditure – As Incurred” values in the Input tab of the 05.02.03 PLPTRM Data Model with Prices values for each year from 2015-16 to 2019-20
- *multiplied* by the proportion of the total annual cost that represents the direct, escalated annual public lighting capital expenditure (i.e. exclusive of overheads) for each year from 2015-16 to 2019-20
- *equals* the “Public Lighting” values for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.3.

The component of the total annual cost that represents the annual escalated overheads allocated to public lighting capital expenditure for each year from 2015-16 to 2019-20 are included in the “capitalised network overheads” and “capitalised corporate overheads” for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.3.

The following elements of this table reconcile to the 05.04.07 MTPTRM Data Model as follows:

- The “Forecast Net Capital Expenditure – As Incurred” values in the Input tab of the 05.04.07 MTPTRM Data Model AER May 2014 Version values for each year from 2015-16 to 2019-20
- *multiplied* by the proportion of the total annual cost that represents the direct, escalated annual metering capital expenditure (i.e. exclusive of overheads) for each year from 2015-16 to 2019-20
- *equals* the “Metering” values for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.3.

The component of the total annual cost that represents the annual escalated overheads allocated to metering capital expenditure for each year from 2015-16 to 2019-20 are included in the “capitalised network overheads” and “capitalised corporate overheads” for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.3.

There is no forecast capital expenditure associated with the “fee and quoted” line item in Table 2.1.3, and there is no PTRM building block revenue calculation for fee based or quoted services. As such the values for “fee and quoted” are zero in Table 2.1.3 and hence no reconciliation has been performed on these values.

For “Connections”, the capital expenditure in Table 2.1.3 is associated with the large customer connection services (which are quoted services) and as such there is no PTRM building block revenue calculation for these services. Consequently, no reconciliation has been performed on these values in Table 2.1.3. The escalated overheads associated with “Connections” are included in the “capitalised network overheads” and “capitalised corporate overheads” for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.3.

### Regulatory Template Table 2.1.4 – Alternative Control Services Opex

The following elements of this table reconcile to the 05.02.03 PLPTRM Data Model with Prices as follows:

- The “Opex” total values in the Input tab of the PTRM 05.02.03 PLPTRM Data Model with Prices values for each year from 2015-16 to 2019-20
- *multiplied* by the proportion of the total annual cost that represents the direct, escalated annual public lighting operating expenditure (i.e. exclusive of overheads) for each year from 2015-16 to 2019-20
- *equals* the “Public Lighting” values for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.4.

The component of the total annual cost that represents the annual escalated overheads allocated to public lighting operating expenditure for each year from 2015-16 to 2019-20 are included in the “capitalised network overheads” and “capitalised corporate overheads” for each year from 2015-16 to 2019-20.

The following elements of this table reconcile to the 05.04.07 MTPTRM Data Model AER May 2014 Version as follows:

- The “Opex” total values in the Input tab of the 05.04.07 MTPTRM Data Model values for each year from 2015-16 to 2019-20

- *multiplied* by the proportion of the total annual cost that represents the direct, escalated annual metering operating expenditure (i.e. exclusive of overheads) for each year from 2015-16 to 2019-20
- *equals* the “Metering” values for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.3.

The component of the total annual cost that represents the annual escalated overheads allocated to metering operating expenditure for each year from 2015-16 to 2019-20 are included in the “capitalised network overheads” and “capitalised corporate overheads” for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.4.

There is no forecast operating expenditure associated with the “Connections” line item in Table 2.1.4, and there is no PTRM building block revenue calculation for “Connections” services. As such the values for “Connections” are zero in Table 2.1.4 and hence no reconciliation has been performed on these values.

For “fee and quoted” there is no PTRM building block revenue calculation for these services. Consequently, no reconciliation has been performed on these values in Table 2.1.4. The escalated overheads associated with “fee and quoted” are included in the “capitalised network overheads” and “capitalised corporate overheads” for each year from 2015-16 to 2019-20 inclusive in the Table 2.1.4.

**1.6. Where the regulatory proposal varies or departs from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme or service target performance incentive scheme as set out in the framework and approach paper, for each variation or departure explain:**

**(a) the reasons for the variation or departure, including why it is appropriate;**

**(b) how the variation or departure aligns with the objectives of the relevant scheme; and**

**(c) how the proposed variation or departure will impact the operation of the relevant scheme.**

Refer to Regulatory Proposal attachment 03.01.03 Ergon Energy Incentive Schemes.

# 2. CLASSIFICATION OF SERVICES

**2.1 Identify each proposed service classification which departs from a service classification set out in the framework and approach paper in the regulatory proposal and explain:**

Ergon Energy has applied the AER's proposed service classifications set out in the final Framework and Approach paper. Therefore, there are no intended departures from the proposed classification of services. The Regulatory Proposal attachment 02.01.01 Classification Proposal describes how the distribution services to be provided by Ergon Energy are classified under Chapter 6 of the National Electricity Rules (Rules).

**(a) the reasons for the departure, including why the proposed service classification is more appropriate; and**

Not applicable.

**(b) how the treatment of the service will differ under the proposed service classification in comparison to that in the framework and approach paper.**

Not applicable.

**2.2 If the proposed service classifications in the regulatory proposal depart from any of the service classifications set out in the framework and approach paper:**

**(a) provide, in a second set of regulatory templates, all information required in each regulatory template in accordance with the instructions contained therein, modified as necessary, to incorporate the proposed service classifications; and**

Not applicable.

**(b) identify and explain where the regulatory templates differ.**

Not applicable.

# 3. CONTROL MECHANISMS

**3.1 For the proposed forecast revenues that Ergon Energy estimates to recover from providing direct control services over the forthcoming regulatory control period provide:**

**(a) formulaic expressions for the basis of control mechanisms for standard control services and for *alternative control services*; and**

Refer to Regulatory Proposal attachment 04.01.00 Compliance with Control Mechanisms.

**(b) a detailed explanation and justification for each component that makes up the formulaic expression.**

Refer to Regulatory Proposal attachment 04.01.00 Compliance with Control Mechanisms.

**3.2 Also demonstrate:**

**(c) how Ergon Energy considers the control mechanisms are compliant with the framework and approach paper; and**

Refer to Regulatory Proposal attachment 04.01.00 Compliance with Control Mechanisms.

**(d) for standard control services, how Ergon Energy considers the control mechanisms are also compliant with clause 6.2.6 and part C of Chapter 6 of the NER.**

Refer to Regulatory Proposal attachment 04.01.00 Compliance with Control Mechanisms.

# 4. STEP CHANGES

**4.1 For all Step changes in forecast expenditure (including those due to changes in regulatory obligations or requirements and those due to changes in Ergon Energy's own policies and strategies) provide:**

**(a) in *regulatory template* 2.17.1 and *regulatory template* 2.17.2 of *regulatory template 2.17*, the quantum of the *Step change* Ergon Energy:**

**i. forecasts to incur in each year of the *forthcoming regulatory control period*;**

**ii. if applicable, has incurred, or expects to incur, in the *current regulatory control period* relative to expenditure previously approved by the AER; and**

**(b) a description of the *Step change:***

Refer to the regulatory templates and Regulatory Proposal attachment 06.01.04 Step Changes.

**4.2 Provide an explanation of:**

**(a) when the change occurred, or is expected to occur;**

**(b) what the driver of the Step change is;**

**(c) how the driver has changed or will change (for example, revised legislation may lead to a change in a regulatory obligation or requirement); and**

**(d) whether the Step change is recurrent in nature;**

Refer to Regulatory Proposal attachment 06.01.04 Step Changes.

**4.3 Provide justification for when, and how, the Step change affected, or is expected to affect:**

**(a) the relevant opex category;**

**(b) the relevant capex category;**

**(c) total opex; and**

**(d) total capex;**

Refer to Regulatory Proposal attachment 06.01.04 Step Changes.

**4.4 Provide the process undertaken by Ergon Energy to identify and quantify the Step change; provide cost benefit analysis that demonstrates Ergon Energy proposes to address the Step change in a prudent and efficient manner, including:**

**(a) the timing of the Step change; and**

**(b) if Ergon Energy considered a 'do nothing' option, evidence of how Ergon Energy assessed the risks of this option compared with other options;**

### Opex Step Changes

Refer to Regulatory Proposal attachment 06.01.04 Step Changes.

## Capex Step Changes – Network

Ergon Energy has not reported any Network capex step changes for the relevant period.

The AER has defined a step change as *"A material difference in forecast expenditure from historic expenditure not attributable to forecast output growth, real price changes or productivity change"*, pursuant to Appendix F of the Regulatory Information Notice (RIN) to Ergon Energy issued 25 August 2014. This is also consistent with the definition / explanation of a step change in respect of operating expenditure provided in the AER's *Expenditure Forecast Assessment Guideline Explanatory Statement*, 2013 (at page 11).

Opex is generally recurrent in nature and able to be forecast based on output growth and productivity changes. Capex on the other hand is generally non-routine in nature and reflects expectations of need, having regard to demand forecasting and to the performance and condition of existing assets. This is reflected in the AER's *Expenditure Forecast Assessment Guideline*, November 2013 (at page 17):

> *"We will generally assess forecast capex through assessing: the need for the expenditure; and the efficiency of the proposed projects and related expenditure to meet any justified expenditure need. This is likely to include consideration of the timing, scope, scale and level of expenditure associated with proposed projects."*

This approach to assessment is consistent with the approach taken by Ergon Energy to developing our total capex. Ergon Energy's approach is based on starting from a base of zero and assessing program need for each year of a regulatory control period, rather than by defining step changes from a trend growth in expenditure.

Ergon Energy has not therefore, included any capex step changes in our response to this requirement.

## Capex Step Changes – Non-Network

### Fleet

No step changes applied.

### Buildings and Property

In forecasting the expenditure for Non-Network Property capex, Ergon Energy utilises a bottom-up methodology aligned to our hub and spoke model and in doing so, ensures greater efficiency in our program of work. Specified and quantified items of work identified in asset life-cycle analysis are combined based on locality and as a result land, easement and building expenditure are reported as a single line of expenditure. This expenditure can be organised into sub-categories based on the hub and spoke model. Due to the applied bottom-up methodology (detailed in supporting documentation) Property doesn't utilise a base-step- trend method.

While trend analysis may assist in observing unexpected spikes in forecast expenditure, it is important that it is not used to validate and rationalise the proposed capital forecast. Smoothing of expenditure over several financial years does not reflect reality or what is most prudent and efficient in meeting Ergon Energy's Non-Network asset requirements during the regulatory control period.

Ergon Energy reports its Non-Network Property expenditure internally using a split between hubs, where expenditure is consolidated and delivered as a large body of work, and spokes, where items of work can be combined or delivered individually to ensure assets continue to meet their demand. Principally, this hub-based expenditure forms the Major program of work, while the spoke-based expenditure forms the Minor program of work.

**4.5 Provide, if the Step change is due to a change in a regulatory obligation or requirement:**

**(a) any relevant variations or exemptions granted to Ergon Energy during the previous regulatory control period or the current regulatory control period;**

**(b) any relevant compliance audits Ergon Energy conducted during the previous regulatory control period or the current regulatory control period;**

Refer to Regulatory Proposal attachment 06.01.04 Step Changes.

**4.6 With reference to specific clauses of the relevant legislative instrument(s), provide the:**

**(a) previous regulatory obligation or requirement; and**

**(b) how the changed regulatory obligation or requirement is driving the Step change.**

Refer to Regulatory Proposal attachment 06.01.04 Step Changes.

# 5. CAPITAL EXPENDITURE

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to capex are as follows:

- 0A.01.01 How Ergon Energy Compares
- 0A.01.02 Journey to the Best Possible Price
- 0A.01.04 Engagement Program
- 0B.01.01 Appendix B: Capital expenditure forecasts for Standard Control Services
- 06.01.05 Meeting the Rule Requirements
- 07.00.01 Asset Renewal Expenditure Forecast Summary
- 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary
- 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary
- 07.00.04 Other System and Enabling Technologies Expenditure Forecast Summary
- 07.00.05 Reliability and Quality of Supply Expenditure Forecast Summary
- 07.00.06 Fleet Expenditure Forecast Summary
- 07.00.07 ICT Expenditure Forecast Summary
- 07.00.09 Unit Cost Methodologies Summary
- 07.00.10 Deliverability Plan
- 07.09.01 Network Capex Summary Model
- 07.09.15 Asset Strategy
- 07.09.16 Contingent Projects
- 07.09.17 Governance Plans Policies and Procedures
- 07.09.24 About Ellipse Estimating
- 07.09.25 Contract Strategy EGM Overview
- 07.09.26 Deliverability Plan – Major Projects.

**General**

**5.1 Provide, in relation to Ergon Energy's total forecast capex, the following information:**

**(a) why the total forecast capex is required for Ergon Energy to achieve each of the objectives in clause 6.5.7(a) of the NER;**

Refer to:

- Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services
- Regulatory Proposal attachment 06.01.05 Meeting the Rules Requirements.

Refer also to the following information:

**NETWORK**

**Asset renewal**

Refer to Section 7.1 Meeting Rules Requirements – The Capital Expenditure Objectives of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary.

### Corporation Initiated Augmentation

Refer to Section 9.1 Meeting Rules Requirements – The Capital Expenditure Objectives of Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary.

### Customer Initiated Capital Works

Refer to Section 7.1 Meeting Rules Requirements – The Capital Expenditure Objectives of Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary.

### Network Reliability and Quality Improvement

Refer to Section 7.1 Meeting Rules Requirements – The Capital Expenditure Objectives of Regulatory Proposal attachment 07.00.05 Reliability and Quality of Supply Expenditure Forecast Summary.

### Other System and Enabling Technologies

Refer to Section 7.1 Meeting Rules Requirements – The Capital Expenditure Objectives of Regulatory Proposal attachment 07.00.04 Other System and Enabling Technologies Expenditure Forecast Summary.

**(b) how Ergon Energy's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER;**

Refer to:

- Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services
- Regulatory Proposal attachment 06.01.05 Meeting the Rules Requirements.

Refer also to the following information:

### NETWORK

### Asset Renewal

Refer to Section 7.2 Meeting Rules Requirements – The Capital Expenditure Criteria of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary.

### Corporation Initiated Augmentation

Refer to Section 9.2 Meeting Rules Requirements – The Capital Expenditure Criteria of Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary.

### Customer Initiated Augmentation

Refer to Section 7.2 Meeting Rules Requirements – The Capital Expenditure Criteria of Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary.

### Network Reliability and Quality Improvement

Refer to Section 7.2 Meeting Rules Requirements – The Capital Expenditure Criteria of Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary.

### Other System and Enabling Technologies

Refer to Section 7.2 Meeting Rules Requirements – The Capital Expenditure Criteria of Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary.

**(c) how Ergon Energy's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER;**

Refer to:

- Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services
- Regulatory Proposal attachment 06.01.05 Meeting the Rules Requirements.

Refer also to the following information:

### NETWORK

### Asset Renewal

Refer to Section 7.2.1 Meeting Rules Requirements – The Capital Expenditure Objectives – Factors of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary.

### Corporation Initiated Augmentation

Refer to Section 9.2.1 Meeting Rules Requirements – The Capital Expenditure Objectives – Factors of Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary .

### Customer Initiated Capital Works

Refer to Section 7.2.1 Meeting Rules Requirements – The Capital Expenditure Objectives – Factors of Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary .

### Network Reliability and Quality Improvement

Refer to Section 7.2.1 Meeting Rules Requirements – The Capital Expenditure Objectives – Factors of Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary.

### Other System and Enabling Technologies

Refer to Section 7.2.1 Meeting Rules Requirements – The Capital Expenditure Objectives – Factors of Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary.

**(d) an explanation of how the plans, policies, procedures and regulatory obligations or requirements identified in regulatory templates 7.1 and 7.3, ~~and consultants reports, economic analysis and assumptions identified in 1.4~~ have been incorporated; and**

Refer to:

- Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services
- Regulatory Proposal attachment 06.01.05 Meeting the Rules Requirements.

Refer also to the following information:

### FLEET

Refer to Regulatory Proposal attachment 07.00.06 Fleet Expenditure Forecast Summary.

### BUILDINGS AND PROPERTY

Refer to Regulatory Proposal attachments 07.08.24 Property Capex Forecast Overview at pages 8-11 and 17-18 and 07.08.21 Property Services AER Forecasting Methodology at pages 3 and 8.

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

#### Asset Renewal

Refer to Appendix B: References of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary.

#### Corporation Initiated Augmentation

Refer to Appendix C: References of 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary.

#### Customer Initiated Capital Works

Refer to Appendix E: References of Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary.

#### Network Reliability and Quality Improvement

Refer to Appendix C: References of Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary.

#### Other System and Enabling Technologies

Refer to Appendix B: References of Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary.

**(e) an explanation of how each response provided to paragraph 5.1 is reflected in any increase or decrease in expenditures or volumes, particularly between the**

**current and forthcoming regulatory control periods, provided in regulatory templates 2.1 to 2.12.**

## FLEET

Refer to Regulatory Proposal attachment 07.00.06 Fleet Expenditure Forecast Summary.

## BUILDINGS AND PROPERTY

Refer to Regulatory Proposal attachment 07.08.24 Property Capex Forecast Overview at pages 4-7 and 12-14.

## ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

## NETWORK

### Asset Renewal

Refer to Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary:

- Section 4: Current Regulatory Control Period Performance
- Section 5: Expenditure Forecast Method
- Section 6: Expenditure Forecast and outcomes for next period.

### Corporation Initiated Augmentation

Refer to Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary:

- Section 4: Current period outcomes at a category level
- Section 5: Expenditure Forecasting Method Sub transmission
- Section 6: Expenditure Forecasting method distribution
- Section 7: Demand Management
- Section 8: Expenditure Forecast and outcomes for next period.

### Customer Initiated Capital Works

Refer to Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary:

- Section 4: Current period outcomes at a category level
- Section 5: Expenditure Forecasting Method
- Section 6: Expenditure Forecast and Outcomes for next period.

### Network Reliability and Quality Improvement

Refer to Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary:

- Section 4: Current Period Outcomes
- Section 5: Expenditure Forecasting Method
- Section 6: Expenditure Forecast and Outcomes for next period.

### Other System and Enabling Technologies

Refer to Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary:

- Section 3: Current Period expenditure and performance against the AER's allowance
- Section 4: Operational Technology
- Section 5: Protection
- Section 6: Miscellaneous.

**5.2 Provide the model(s) and methodology Ergon Energy used to develop its total forecast capex, including;**

**(a) A description of how Ergon Energy prepared the forecast capex, including:**

**i. how its preparation differed or related to budgetary, planning and governance processes used in the normal running of Ergon Energy's business;**

Refer to Regulatory Proposal attachment 07.09.17 Governance, Plans, Policies and Procedures which provide details of our internal governance arrangements and other policies and procedures.

Refer to Ergon Energy's Expenditure Forecast Methodology 2015 to 2020 submitted to the AER in November 2013 and our Expenditure summary documents for capex categories which provide details of how we have developed forecasts to meet regulatory requirements.

**ii. the processes for ensuring amounts are free of error and other quality assurance steps; and**

Ergon Energy engaged an independent review of revenue models in order to check the logical integrity and internal consistency of the calculations contained in these models. This included checking the formulae calculations as well as a high level analytical review of several outputs and processes of certain revenue models.

**iii. if and how Ergon Energy considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.**

Refer to Appendix B of Ergon Energy's Regulatory Proposal (in particular Section 4.2) and 0A.00.01 An Overview of Our Regulatory Proposal and supporting documents 0A.01.04 Engagement Program and 0A.01.02 Best Possible Price, for how our ongoing conversation with our customers influences our proposed investment program.

Refer also to the following information:

### NETWORK

### Total Network Capex

Refer to Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary:

- Section 2: Methodology and Approach
- Section 3: Specified Investments Methodology
- Section 4: Program of Work Investments Methodology.

### Asset Renewal

Refer to Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary:

- Section 5: Expenditure Forecasting Methodology.

### Corporation Initiated Augmentation

Refer to Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary:

- Section 5: Expenditure Forecasting Method – Subtransmission
- Section 6: Expenditure Forecasting Method – Distribution.

### Customer Initiated Capital Works

Refer to Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary:

- Section 5: Expenditure Forecasting Methodology.

### Network Reliability and Quality Improvement

Refer to Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary:

- Section 5: Expenditure Forecasting Methodology.

### FLEET

Refer to the following documents:

- Basis of Preparation for regulatory template 2.6, Table 2.6.1
- Basis of Preparation for regulatory template 2.6, Table 2.6.3.

The preparation of the capex forecast utilised data from the Ergon Energy ellipse equipment register to provide a report of the scheduled replacement instances for each individual fleet asset as they fell due of the nominated AER period.

Cashflow management/smoothing was then applied across the various asset categories to ensure that the annual physical quantities and capex required nominated eliminated historical peaks and troughs in the fleets age profile.

This ensured that prudent, effective and efficient replacement of the fleet could be undertaken in a planned achievable/ repeatable manner.

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### BUILDINGS AND PROPERTY

Refer to:

- Regulatory Proposal attachment 07.08.24 Property Capex Forecast Overview at pages 4 and 7-18
- Regulatory Proposal attachment 07.08.21 Property Services AER Forecasting Methodology at pages 8-13
- Property Business Cases:
  - Regulatory Proposal attachment 07.08.14 Maryborough Searle St Development G2 Business Case at pages 3-6
  - Regulatory Proposal attachment 07.08.16 Toowoomba South St Redevelopment G2 Business Case at pages 3-6
  - Regulatory Proposal attachment 07.08.15 Property Minor Program Business Case at pages 3-19.

**(b) any source material used (including models, documentation or any other items containing quantitative data): and**

### FLEET

Refer to Regulatory Proposal attachment 07.00.06 Fleet Expenditure Forecast Summary.

### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

### Total Network Capex

Refer to:

- Regulatory Proposal attachment 07.09.01 Network Capex Summary Model
- Regulatory Proposal attachment 07.09.27 Ergon Energy Network Capital Expenditure Forecast Model
- Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary.

### Customer Initiated Capital Works (CICW)

Refer to:

- Regulatory Proposal attachment 07.03.01 Ergon Energy CICW Forecast Model
- Regulatory Proposal attachment 07.03.02 CICW Model Report.

**(c) calculations that demonstrate how data from the source material has been manipulated or transformed to generate data provided in the regulatory templates.**

### FLEET

Refer to:

- Regulatory Proposal attachment 07.06.09 Full Listing Ellipse – to determine annual cashflow management/smoothing quantities & CAPEX
- Regulatory Proposal attachment 07.06.08 Fleet Management 15 Year AER Plan – this details the breakdown of the annual fleet replacement quantities and CAPEX throughout the AER period

#### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

#### NETWORK

Refer to:

- Regulatory template 2.2 Repex Basis of Preparation document – source of data and methodology sections
- Regulatory template 2.3 Augex Project Data Basis of Preparation document – source of data and methodology sections.

### 5.3 Identify which items of Ergon Energy's forecast capex have been:

**(a) derived directly from competitive tender processes;**

#### FLEET

- Tendered supply arrangement for MEWP, Crane Borer Plant, Trailers, Service Bodes (LCV).
- Government Pricing – Car, LCV
- Local Buy – HCV

#### BUILDINGS AND PROPERTY

Refer to Regulatory Proposal attachment 07.08.24 Property Capex Forecast Overview.

#### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

#### NETWORK

Refer to Section 2: Methodology and Approach of Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary.

**(b) based upon competitive tender processes for similar projects;**

#### FLEET

Not applicable.

#### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

#### ICT

Not applicable.

### NETWORK

Refer to Section 2: Methodology and Approach of Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary.

**(c) based upon estimates obtained from contractors or manufacturers;**

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

### ICT

Not applicable.

### NETWORK

Refer to Section 2: Methodology and Approach of Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary.

**(d) based upon independent benchmarks;**

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

Not applicable.

**(e) based upon actual historical costs for similar projects; and**

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

Refer to Section 2: Methodology and Approach of Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary.

**(f) reflective of any amounts for risk, uncertainty or other unspecified contingency factors, and if so, how these amounts were calculated and deemed reasonable and prudent.**

### FLEET

Fleet assets are involved in accidents/ incidents where it is uneconomic to repair. In these cases new assets are purchased to replace them. Ergon Energy does not have comprehensive insurance cover of its fleet assets. Replacement of written-off fleet assets are self-funded i.e. capitalised against the Fleet capex budget.

### BUILDINGS AND PROPERTY

Refer to response to 5.2(a).

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

In general Ergon Energy have not included an allowance for contingency or risk in relation to forecast expenditure for the next regulatory control period. Specific works in progress only apply risk or contingency where the specific aspects of a project deem it appropriate.

**5.4 Provide all documents which were taken into account and relate to the deliverability of forecast capex and explain the proposed deliverability.**

Refer to Regulatory Proposal attachment 07.00.10 Deliverability Plan.

Refer also to the following information:

### BUILDINGS AND PROPERTY

Refer to the Regulatory Proposal attachments used in the preparation of the capex forecast:

- 07.08.01 Property Strategic Plan
- 07.08.02 Master Plan Exec Summary
- 07.08.03 Asset Management Plan
- 07.08.04 Property Accommodation Manual Part A
- 07.08.05 Property Accommodation Manual Part B
- 07.08.06 Non Network Property Strategy Review
- 07.08.07 Letter sent SHMs Response with Ergon Energy Property Strategy
- 07.08.08 Board Garbutt Redevelopment Approval 2014
- 07.08.09 QLD Treasury Garbutt BC Review_2014
- 07.08.10 SHM Approval Gate 3 Townsville Garbutt 2014
- 07.08.11 Rockhampton S2 Development PART A G3 Business Case
- 07.08.12 SHM Approval Gate 3 Glenmore Rd Rockhampton

- 07.08.13 Townsville Garbutt Redevelopment PART A G3 Business Case
- 07.08.14 2015-20 Maryborough Searle St Development G2 Business Case
- 07.08.15 2015-20 Property Minor Program Business Case
- 07.08.16 2015-20 Toowoomba South St Redevelopment G2 Business Case
- 07.08.17 LCC Consolidation Report STATEWIDE
- 07.08.18 LCC Consolidation Report Northern Region
- 07.08.19 LCC Consolidation Report Central Region
- 07.08.20 LCC Consolidation Report Southern Region
- 07.08.21 Property Services AER Forecasting Methodology
- 07.08.22 AER 2010-15 Expenditure Review
- 07.08.23 AER2015-20 CAPEX Major PE Case Study
- 07.08.24 Property Capex Forecast Overview
- 07.08.25 Capex Program
- 07.08.26 Property Services Operating Expenditure Plan 2015-20
- 07.08.27 AER 15-20 CAPEX Forecast Reg Submission
- 07.08.28 Statewide LCC Planning Report
- 07.08.29 AER2015-20 CAPEX Program
- 07.08.30 Searle St Maryborough Assumptions Calculations
- 07.08.31 South St Toowoomba Assumptions Calculations
- 07.08.32 Minor Program Unspecified Projects Calculations.

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

The Network Forecast Expenditure Summary documents contain information related to the proposed delivery of investments for each Network category:

- Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary
- Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary
- Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary
- Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary
- Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary.

## 5.5 Describe each capex category and expenditures comprising these categories identified in the regulatory templates, including:

**(a) key drivers for expenditure;**

Please refer to Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services.

Refer also to the following information:

### FLEET

Refer to Regulatory Proposal attachment 07.00.06 Fleet Expenditure Forecast Summary.

### BUILDINGS AND PROPERTY

Refer to Regulatory Proposal attachment 07.08.21 Property Services AER Forecasting Methodology at sections 1.2 and 2.

### ICT

Refer to Regulatory Proposal attachment 07.00.07 ICT Expenditure Forecast Summary.

### NETWORK

#### Asset Renewal

Refer to Section 3: Nature of Expenditure of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary.

#### Corporation Initiated Augmentation

Refer to Section 3: Nature of Expenditure of Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary.

#### Customer Initiated Capital Works

Refer to Section 3: Nature of Expenditure of Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary.

#### Network Reliability and Quality Improvement

Refer to Section 2: Nature of Expenditure of Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary.

#### Other System and Enabling Technologies

Refer to Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary:

- Section 4.1: Nature of Expenditure – Operational Technology
- Section 5.1: Nature of Expenditure – Protection
- Section 6.1: Nature of Expenditure – Miscellaneous.

**(b) (b) an explanation of how expenditure is distinguished between:**

**i. demand driven and non-demand driven augmentation capital expenditure;**

Refer to Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services.

Refer also to the following information:

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Not applicable.

### ICT

Not applicable.

### NETWORK

Refer to Regulatory Proposal attachment 7.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary:

- Section 3.4: Relationship between CIA and CICW expenditure
- Section 7: Demand Management.

**ii. connections expenditure and augmentation capital expenditure;**

Refer to to Regulatory Proposal, Appendix B: Capital expenditure forecasts for Standard Control Services.

Refer also to the following information:

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Not applicable.

### ICT

Not applicable.

### NETWORK

Refer to Section 3.4: Relationship between CIA and CICW expenditure of Regulatory Proposal attachment 7.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary.

Refer to Section 3.3: Distinction between CIA and CICW expenditure of Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary.

**iii. replacement capital expenditure driven by condition and asset replacements driven by other drivers (e.g. the need for demand or non-demand driven augmentation capital expenditure); and**

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Not applicable.

### ICT

Not applicable.

### NETWORK

Refer to Section 5: Expenditure Forecasting Methodology of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary.

**iv. any other capex category or opex category where Ergon Energy considers that there is reasonable scope for ambiguity in categorisation.**

### FLEET

Not applicable.

### BUILDINGS AND PROPERTY

Not applicable.

### ICT

Not applicable.

### NETWORK

Refer to Regulatory Proposal attachment 07.00.05 Reliability Quality of Supply Expenditure Forecast Summary and Regulatory Proposal attachment 07.00.04 Other System Enabling Technologies Expenditure Forecast Summary.

# 6. REPLACEMENT CAPITAL EXPENDITURE MODELLING

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to repex are as follows:

- 0B.01.01 Appendix B: Capital expenditure forecasts for Standard Control Services
- 07.00.01 Asset Renewal Expenditure Forecast Summary
- 07.01.01 Line Asset Defect Mgmt Method.

**6.1 In relation to information provided in regulatory templates 2.2 and with respect to the AER's repex model, provide:**

**(a) In relation to individual asset categories set out in the regulatory templates, provide in a separate document:**

**(i) a description of the asset category, including:**

Ergon Energy has an Enterprise Resource Planning (ERP) application called Ellipse which is used to manage internal and external resources and includes assets and materials. Smallworld is the geographical information system (GIS) used to capture, store, analyse, manage and present data which is linked to a geographic location. Both of these systems have been used to produce the required data for the defined asset categories in regulatory template 2.2 and the AER Repex model.

A description of each asset category is provided below.

**A. the assets included and any boundary issues (i.e. with other asset categories);**

### Poles

This asset category represents all Ergon Energy owned poles and towers (including bollards) used to support overhead conductors but excludes dedicated public lighting poles which are included under the Public Lighting category. Dedicated public lighting poles are those which only have public lighting circuits attached to them.

### Pole top structures

This asset category includes all Ergon Energy owned crossarms, insulators, and terminations mounted on poles used to support overhead conductors and related assets. Exclusions to this asset class involve overhead conductor and any pole mounted assets included in other asset categories, i.e. pole mounted transformers and pole mounted switchgear which include links, fuses and air break switches.

### Conductors

This asset category includes Ergon Energy owned conductors, overhead earthwires, spreaders and other conductor fittings. This excludes customer services which are included under the Services category.

### Underground Cables

This asset category includes all Ergon Energy owned underground subtransmission, high voltage and low voltage distribution cables, cable pits/tunnels, joint pits, joints and terminations.

### Service Line

This asset category includes all Ergon Energy owned customer overhead service wires and underground service wires through distribution pillars which directly connect the customer's premises to the distribution network.

### Distribution Transformers

This asset category includes all Ergon Energy owned distribution pole mounted transformers and reactors, pole mounted isolating transformers, kiosk (padmount) transformers, ground mounted transformers and pole mounted regulators. This asset category does not include current instrument transformers, voltage transformers and high voltage metering units.

### Zone Transformers

This asset category includes all Ergon Energy owned power transformers, reactor transformers, regulators, oil-filled reactors auxiliary transformers, earthing transformers and fixed (off-load) tap changers. Transformers mounted within self-contained substations are reported against "kiosk" mounting type and all components of the substations are securely enclosed within a confined unit. Padmount substations are also encased units and therefore transformers within these units are classified as a kiosk mounting type.

Ergon Energy recognises that the following AER asset categories *'Ground Outdoor / Indoor Chamber Mounted, >=22kV & <=33kV, =15MVA'* and *'Ground Outdoor / Indoor Chamber Mounted, >=22kV, 600kVA, Multiphase'* incorporate both distribution and zone substation transformers.

### Distribution Switchgear

This asset category includes all Ergon Energy owned distribution ring main switches, 3 phase reclosers, Single Wire Earth Return (SWER) reclosers, gas switches, air break switches and HV and LV fuse carriers. Ergon Energy does have other devices being links and live line clamps that could have been included, but they are minor low cost assets not well represented in the corporate ERP and so they have not been included.

### Zone Switchgear

This asset category includes all Ergon Energy owned fuses and switches which include, power fuses, isolators, earth switches, fault throw switches, links and reclosers and circuit breakers which include oil, vacuum and gas insulated versions which cater for different voltage levels, load current levels and projected fault current levels in various parts of the power system.

### Public Lighting

This asset category includes all Ergon Energy owned lamps, luminaires, brackets and dedicated public lighting poles / columns. This asset category does not include those assets which are not owned by Ergon Energy.

### SCADA and Protection

This asset category includes all Ergon Energy owned field devices which include, protection relays, remote terminal units and local stations, master station assets which include, servers, routers, controllers and Audio Frequency Load Control (AFLC), which include HV coupling cells, LV controllers, and LV transmitters. The AER asset category of *'Local Network Wiring Assets'* is incorporated within this category.

### Communications

This asset category includes all Ergon Energy owned telecommunication equipment which includes P25 network, cellular data network, CoreNet, corporate communications, multiplexing, routing and communication switching equipment, point-to-point and multi-point data systems, land mobile radio systems, communications sites, infrastructure assets. The AER asset category of *'Local Network Wiring Assets'* is incorporated within this category.

### Zone Other Assets

This asset category includes all Ergon Energy owned current transformers (CTs) which include, external (i.e. external to enclosed compartments) and internal (i.e. mounted within enclosed compartments); voltage transformers (VTs) which include, oil insulated and epoxy insulated designs; capacitor banks which include, interconnected individual capacitor cans, air cooled or oil filled reactors, tuning capacitors, reactors and associated contactors; and static VAR compensators which include forced air and water based designs.

**B. an explanation of how these matters have been accounted for in determining quantities in the age profile;**

### Poles

Ergon Energy uses its ERP and GIS system (described above) to determine the number of poles that are in its network and can break this down into its species, voltage and whether it has been nailed or rebutted. Public lighting poles / columns can also be separated out at this point.

However, the age profile for poles is estimated because it is not possible to provide actual information in relation to age profile dates for all asset categories within the Poles Asset Group. This inferring process is included in the Reset RIN Basis of Preparation Documents for regulatory template 2.2 Repex.

### Pole top structures

This asset category is not included in the repex template for Asset Age Profile. Ergon Energy does not record crossarms as separate assets in corporate systems and the number of pole tops is calculated by counting the number of individual crossarms recorded against each pole asset.

### Conductors

Ergon Energy uses its GIS system to determine the length of overhead conductor that it owns. Installation information has been collected since 2008, however this represents a small percentage of the current network therefore a reliable age profile is difficult to obtain. The inferring process to determine the conductor age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Underground Cables

Ergon Energy determined the length of Subtransmission, Distribution and LV underground cable from its GIS system. Installation information has been collected since 2008, however this represents a small percentage of the current network therefore a reliable age profile is difficult to obtain. The inferring process utilised to determine the underground cable age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Services

Ergon Energy determines the population of overhead and underground services using its GIS system. An accurate picture of the age profile of overhead customer services is difficult due to the considerable impacts of natural disasters such as cyclones and flooding in Queensland. Post disaster restoration records of replacements have not proven to be effective. The inferring process utilised to determine the services age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Distribution Transformers

Ergon Energy determines the population for the asset category of distribution transformers using its GIS and ERP systems. An accurate determination of the age profile for the asset category of distribution transformers is not possible as distribution transformers usually employ a run to end of life strategy and the year of manufacture/installation has not been collected routinely. The inferring process utilised to determine the age profile for this asset category is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Zone Transformers

Ergon Energy determines the population for the asset category of zone transformers using its ERP system. An actual age profile for zone substation transformers was sourced from Ergon Energy's ERP which was obtained from the manufacturer's nameplate. Ergon Energy's Condition Based Risk Management (CBRM) modelling for substation power transformers provides identification, processing and collation of individual asset records and characteristics from multiple sources. The methodology used to determine quantities in the asset age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Distribution Switchgear

Ergon Energy determines the population for the asset categories incorporating distribution switchgear using its GIS and ERP systems. The age profile for this asset category is inferred as little corporate data has been collected on these assets. The inferring process utilised to determine the age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Zone Switchgear

Ergon Energy determines the population for the asset category of zone switchgear using its ERP system. The age profile for this asset category is inferred as little corporate data has been collected on these assets. Ergon Energy's CBRM modelling for substation circuit breakers, outdoor isolators, distribution reclosers and ring main units provides identification, processing and collation of individual asset records and characteristics from multiple sources. The inferring process utilised to determine the asset age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Public Lighting

Ergon Energy determines the population for the categories of public lighting using its GIS and ERP systems.

Public lighting poles (columns) can be separated from other types of poles based on the type of pole, category and species entered. An inferred age profile has been used for public lighting poles (columns).

The age profile for public lighting lamps is accurate from 2010 however it was assumed that the brackets were installed at this time as no asset data is collected on brackets. An inferred age profile has been used for lamps in the period before 2010.

The age profile for luminaires was determined by recording the year of manufacture at the time of performing Bulk Lamp Replacement programs since 2010 however before this an estimate is required due to no year of manufacture being recorded for the luminaires. An inferred age profile has been used for luminaires in the period before 2010.

The inferring process utilised to determine the age profile for lamps and brackets, luminaires and steel poles (columns) is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### SCADA and Protection

Ergon Energy has determined an estimated asset age population using its ERP system and Protection Database System. Actual asset age has been included where asset information is available for Supervisory control and data acquisition (SCADA) network control master stations, RTUs and protection relays. The age profile for this asset category is inferred as limited corporate data is available for these assets. Protection systems, field devices and local wiring have inferred age profiles due to incomplete records existing. The process utilised to determine the asset age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Communications

Ergon Energy determines the population for the asset categories incorporating communications using its ERP, Stride, VQSM, GIS system, and UbiNet. The age profile for this asset category is inferred as corporate data is incomplete on these assets. The inferring process utilised to determine the age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

### Zone Other Assets

Ergon Energy determines the population for the asset categories incorporating current transformers, voltage transformers and capacitor banks using its ERP system. An actual age profile for current transformers, voltage transformers and capacitor banks was sourced from Ergon Energy's ERP which was obtained from the manufacturer's nameplate. Ergon Energy's CBRM modelling for substation instrument transformers and substation capacitor banks provides identification, processing and collation of individual asset records and characteristics from multiple sources. The methodology used to determine quantities in the asset age profile is defined in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

**C. an explanation of the main drivers for replacement (e.g. condition); and**

For an overview of the main drivers for asset replacement, refer to section 6.1 of Regulatory Proposal attachment 07.00.01 Asset Renewal Expenditure Forecast Summary. In addition, the following response is provided per asset category.

### Poles

The main driver for replacement of poles is condition or as they fail. Issues that may affect the condition of the poles are identified through the Overhead and Underground Line Inspection Program which involves inspection of the pole below and near ground line. Level 2 Serviceability Assessment which calculates how the configuration of the pole loading affects the pole condition.

Poles are also replaced due to assisted asset failures such as storms, fire, natural disasters, and vegetation or due to third party damage such as vehicle impact. Poles may also be replaced where risks are identified such as erosion on riverbanks which will impact on the pole.

Poles may also need to be replaced to meet statutory clearances between ground and structures, or where the pole configuration is altered beyond the strength of the existing pole. Poles that cross navigable waterways may not be of sufficient height to allow vessels to safely clear lines and it may be decided after risk assessment to replace with taller poles.

Poles are also replaced during subtransmission pole top replacement.

Poles are also replaced as a result of line rebuilding associated with conductor replacement. This is because the design span lengths and pole strengths required to support some modern conductors are inadequate. In some cases this leads to the line being rebuilt on a new alignment.

### Pole top structures

The main driver for replacement of pole top structures is condition. Issues that affect the condition of the pole top structures are identified through the Overhead and Underground Line Inspection Program. Wood crossarms, which represent a high proportion of the population, can deteriorate due to termite attack, fungal decay, lightning and splitting due to weather, age and leakage current burns. Steel crossarms and brackets can deteriorate due to corrosion in coastal or industrial areas.

Pole top structures such as insulators are also replaced due to damage caused by flashover, leakage, storms and corrosion or third party damage.

Pole top structures are also replaced as a result of line rebuilding associated with conductor replacement.

Other drivers for replacement are the obsolescence of Cast Iron Cable Pot heads which due to corrosion allows for moisture ingress to the cable termination which can lead to catastrophic failure of the joint and cable.

### Conductors

The main driver for replacement of overhead conductors is condition. Issues that affect the condition of overhead conductors and may lead to deterioration are mechanical stress/ fatigue due to conductor movement, corrosion/ deterioration of conductor materials/ fittings or damage to strands due to phases clashing together. Overhead conductors can also be replaced due to storms, vegetation, vehicle impact, wildlife, or fires.

Overhead conductors may also need to be replaced because of changes to the network require more current carrying capacity but this is generally funded as part of augmentation.

Obsolescence is also a driver for replacement with 7/.064 Hard Drawn Bare Copper (HDBC) High Voltage conductor being replaced throughout the network due to significant safety concerns.

### Underground Cables

The main driver for replacement of underground cables is condition. Issues that affect condition of underground cables and may lead to deterioration are mechanical stress due to ground movement on the cable/ joints, corrosion/ deterioration of conductor materials due to water ingress, age related degradation of insulating materials, damage caused by third parties or termite and vermin attack.

Underground cables may also be replaced if the cables have become obsolete like pressurised subtransmission cables which are either oil or gas filled. These types of cables require specialised jointing resources and are no longer being supported by manufacturers and cable suppliers.

Underground cables may also need to be replaced due to changes in the network which requires increased current carrying capacity in the cables but this is generally funded as part of augmentation.

### Services

The main driver for replacement of overhead and underground customer services is condition. Issues that affect the condition of overhead customer services are identified through the Overhead and Underground Line Inspection Program or customers reporting arcing or fallen service lines. Overhead customer services may have issues of degradation of insulation around the conductors due to ultraviolet radiation, aging, or fatigue which leads to arcing occurring between the active and neutral conductors.

Insulation degradation has led to a number of safety issues with colour coded services, neutral screened services and a specific manufacturer's Cross Link Poly Ethylene (XLPE) service cable.

Open wire service cables have been recognised as a significant safety issue and programs have been run to remove them from service via replacement with multi-core service cable.

Overhead customer services may also be replaced due to damage caused by vegetation, storms, or fires. Issues with statutory clearance requirements may also require replacement of overhead customer services.

Underground customer services may have issues due to degradation of the insulation, moisture ingress or third party damage but are usually only detected following an interruption to supply caused by the failure.

### Distribution Transformers

The main driver for replacement of distribution transformers is failure in service due to triggers such as storms, lightning, wind, rain, wildlife, corrosion, vegetation or overload.

The other driver for replacement of distribution transformers is condition. Issues that affect the condition of distribution transformers are identified through the Overhead and Underground Line Inspection Program, Pole Mounted HV Equipment Routine Inspection Program and Distribution Transformer Oil Sampling Program. Distribution transformers may need replaced due to damage caused by failures associated within the winding of the transformer or damage to the bushings. Pole mounted transformers may be subjected to failures due to damage or corrosion to mounting brackets and supporting structures. Other condition issues may be caused by storms, vegetation, or animals bridging across live components.

Distribution transformers may also be replaced if its rating is no longer sufficient to supply the required loading but this is generally funded as part of augmentation.

### Zone Transformers

The main drivers for replacement of zone transformers are failed in service and operational wear.

Issues that affect the condition of zone transformers are identified through Regulatory Proposal attachment 07.01.05 Power Transformer Replacement and Refurbishment. Zone Transformers may need to be replaced due to degradation of the degree of polymerisation (DP) which measures insulation strength; unfavourable dissolved gas analysis which ascertains a transformer's activity offer a prediction of transformer failure;

and diagnostic of water content in paper (WCP) which can indicate ingress of moisture within transformers and contribute to electrical breakdowns.

Zone transformers may also be replaced if its rating is no longer sufficient to supply the required loading but this is generally funded as part of augmentation.

Ergon Energy has proposed to address zone switchgear issues through refurbishment and pre-emptive replacement (of known problematic model types) and planned replacement programs based upon qualification of risk (e.g. past expected operational age).

### Distribution Switchgear

The main driver for replacement of distribution switchgear is failure in service due to triggers such as storms, lightning, wind, rain, wildlife, corrosion, vegetation or overload.

The other driver for replacement of distribution switchgear is condition. Issues that affect the condition of distribution switchgear are identified through a number of programs including the Overhead and Underground Line Inspection Program, Pole Mounted Switch Inspection and Maintenance Program, Ring Main Unit Maintenance Program and Freestanding Ring Main Unit Inspection Program. Distribution switchgear may need replaced due to failures of the components used to insulate the switches, mechanical misalignment, corrosion on some switchgear preventing operation, broken or cracked insulators, or damage due to animals, vegetation or storms.

Safety concerns are also a driver for replacement of certain manufacturers' air break switches, and replacement of Expulsion Drop Out (EDO) Fuses in high fire risk areas.

### Zone Switchgear

The main drivers for replacement of zone switchgear are failed in service and operational wear.

Issues that affect the condition of zone switchgear are identified through the Outdoor Isolators and Earth Switches Replacement and Refurbishment and Circuit Breakers and Switchboards Replacement and Refurbishment Programs. Zone Switchgear may need to be replaced due to insulation and mechanism failures – especially of particular model types with known inherent problems.

Zone Switchgear may also be replaced if its rating is no longer sufficient to cater for the required loading but this is generally funded as part of augmentation.

Ergon Energy has proposed to address zone switchgear issues through refurbishment and pre-emptive replacement (of known problematic model types) and planned replacement programs based upon qualification of risk (e.g. past expected operational age).

### Public Lighting

The main driver for replacement of public lighting pole / column replacement is condition. Issues that affect the condition of the pole are identified during the Overhead and Underground Line Inspection Program which involves inspection and treatment of the pole below and near ground line.

Poles are also replaced due to storms, vegetation, or due to third party damage.

Lamps are replaced under a Bulk Lamp Replacement Program. Lamp issues requiring replacement are also captured under the Public Lighting Road Patrol Program. Luminaires may also be replaced due to condition such as corrosion, insect infestation, or due to technology changes in the lamps.

### SCADA, Protection and Communications

The main drivers for replacement of field and communication assets are failed in service and exceeding expected operational life.

Other issues that affect the condition of these devices are identified through a number of Regulatory Proposal attachments including:

- 07.09.13 Management Plan Network Communications Infrastructure;
- 07.01.22 Telecom Network Strategy 2014-20;
- 07.04.05 Integrated NO Centre INOC Strategy;
- 07.09.12 Management Plan Protection and Control;
- 07.04.14 Network Control Strategy;
- 07.01.23 Audio Frequency Load Control Strategy;
- 07.04.04 10yr 2015-25 Master Station SCADA Strategy;
- 07.01.26 Engineering Report RTU Replacement Program;
- 07.01.06 Protection Relay Replacement Engineering Report;
- 07.04.09 Sensitive Earth Faults SC Protection Strategy;
- 07.04.15 Network Protection Strategy; and
- 07.04.11 Protection Review Rectification Strategy.

Reasons these assets may need to be replaced include mechanism failure – especially of particular model types with known inherent problems; inability to continue service support (hardware and software); upgrade of firmware (to remove existing software problems) or wanting to extend asset life such as the replacement of a faulty control card within an RTU.

Field devices may also be replaced if its rating is no longer sufficient to cater for the required network or primary plant requirements (e.g. voltage rating, network protection scheme etc.) but this is generally funded as part of augmentation.

Ergon Energy has proposed to address field and communication asset issues through refurbishment and pre-emptive replacement (of known problematic model types) and planned replacement programs based upon qualification of risk (e.g. past expected operational age).

### Zone Other Assets

The main drivers for replacement of zone other assets are failed in service and operational wear.

Other issues that affect the condition of these devices are identified through a number of Regulatory Proposal attachments including:

- 07.09.12 Management Plan Protection and Control;

- 07.01.10 Engineering Report Static VAR Compensators SVC Replacement and Refurbishment;
- 07.01.12 Engineering Report Capacitor Banks Replacement and Refurbishment;
- 07.09.10 Management Plan Zone and Bulk Supply Sub Plant and Equipment; and
- 07.01.08 Engineering Report Instrument Transformer Replacement and Refurbishment_Confidential.

Reasons these assets may need to be replaced include mechanism failure – especially of particular model types with known inherent problems.

Field devices may also be replaced if its rating is no longer sufficient to cater for the required rating but this is generally funded as part of augmentation.

Ergon Energy has proposed to address zone other asset issues through refurbishment and pre-emptive replacement (of known problematic model types) and planned replacement programs based upon qualification of risk (e.g. past expected operational age) and consideration of CBRM analysis.

**D. an explanation of whether the replacement unit cost provides for a complete replacement of the asset, or some other activity, including an extension of the asset's life (e.g. pole staking) and whether the costs of this extension or other activity are capitalised or not.**

### Poles

The replacement costs provided for each pole type catering for different voltage ratings are an estimate, as different methodologies have been applied to extract assets dependent upon voltage and pole type. The replacement costs presented cater for a complete replacement of each pole type at the defined voltage which includes labour requirements and material costs while maintaining efficiencies by bundling pole replacements in the same geographical area together and poles replaced as a result of conductor replacement projects via complete line rebuilding.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

The costs for pole staking which have been provided are an estimate. Pole staking is classed as a refurbishment activity and not an asset which means that the costs are determined from Work Order data and the number of poles that were staked. The cost of pole staking is capitalised as a life extension activity.

The allocation process utilised to determine the costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Pole top structures

The replacement costs provided for pole top structures are an estimate dependent upon different voltage ratings. The replacement cost presented caters for a complete replacement of the pole top structure, which includes the crossarm and insulators, and includes labour requirements and material costs while maintaining efficiencies by bundling pole top structure replacements in the same geographical area together and pole tops replaced as a result of conductor replacement projects via complete line rebuilding.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Conductors

The replacement costs provided for conductors are an estimate catering for different voltage ratings. The replacement cost presented caters for the replacement of the section of overhead conductor and includes labour requirements and material costs, works and projects that are a combination of reconductoring (replacing the conductor only) and complete line rebuilding.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Underground Cables

The replacement costs provided for underground cables are an estimate dependent upon different voltage ratings. The replacement costs presented cater for the complete replacement of the part of the underground cable and includes labour requirements and material costs while maintaining efficiencies by bundling underground cable replacements in the same geographical area together to lower costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Services

The replacement costs provided for residential and commercial services are an estimate. The replacement costs presented cater for the complete replacement of the service cable and includes labour requirements and material costs while maintaining efficiencies by bundling service replacements in the same geographical area together to lower costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Distribution Transformers

The replacement costs provided for distribution transformers are an estimate. The replacement costs presented caters for the complete replacement of distribution transformers and includes labour requirements and material costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Zone Transformers

The replacement costs for zone transformers provided are an estimate. The replacement costs vary for each transformer type dependent up on size, voltage supply and design characteristics. The replacement costs provided is for a complete replacement of zone transformers and includes labour requirements and material costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Distribution Switchgear

The replacement costs provided for distribution switchgear are an estimate. Replacement costs presented cater for the complete replacement of distribution switchgear at the required voltage and are inclusive of labour requirements and material costs.

The inferring process utilised to determine the replacement unit cost is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Zone Switchgear

The replacement costs provided for zone switchgear are an estimate. The replacement costs vary for each asset type (i.e. fuse, circuit breaker or switch) dependent upon size, voltage supply and design characteristics. The replacement costs provided is for a complete replacement of zone switchgear and includes labour requirements and material costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Public Lighting

The replacement costs which have been provided are an estimate, for the components of public lighting. The replacement costs provided is for the replacement of the component parts which contribute to the asset category of public lighting and includes labour requirements and material costs while maintaining efficiencies by bundling public lighting replacements in the same geographical area to lower costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2

Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### SCADA and Protection

The replacement costs provided for SCADA and protection equipment are an estimate. The replacement costs vary for each asset type (i.e. protection relays, local stations, Remote Terminal Units (RTUs), AFLC and master stations) dependent up on size, quantity and design characteristics. The replacement costs provided is for a complete replacement and includes labour requirements and material costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Communications

The replacement costs provided for communication equipment are an estimate. The replacement costs vary for each asset type (i.e. communication network assets, site infrastructure, and linear assets) dependent up on size, quantity and design characteristics. The replacement costs provided is for a complete replacement and includes labour requirements and material costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

### Zone Other Assets

The replacement costs provided for zone other assets are an estimate. The replacement costs vary for each asset type (i.e. AC systems, DC systems, current transformers, voltage transformers, capacitor banks and static VAR compensators) dependent up on size, quantity and design characteristics. The replacement costs provided is for a complete replacement and includes labour requirements and material costs.

The allocation process utilised to determine the replacement costs is defined in the Category Analysis RIN Basis of Preparation document for regulatory template 2.2 Replacement Expenditure 1 July 2013 to 30 June 2014 attached to the Reset RIN Basis of Preparation document.

**(ii) an estimate of the proportion of assets replaced for each year of the current regulatory control period, due to:**

**A. aging of existing assets (e.g. condition, obsolesce, etc.) that should be largely captured by this form of replacement modelling;**

Table 1 shows the percentage of the total population of assets replaced due to aging, condition, obsolescence during the current regulatory control period. The current financial year (e.g. 2014-15 - the final year of the regulatory control period) is not shown in the table below as actual works have not yet been completed, however the proportion of asset replacements are expected to be within the ranges illustrated in the preceding years.

**Table 1: Proportion of total asset population replaced due to age and condition**

| Summary Category | | 2010/11 | 2011/12 | 2012/13 | 2013/14 |
|---|---|---|---|---|---|
| **Poles** | % replaced | 0.32% | 0.45% | 0.40% | 0.40% |
| | % staked | 0.31% | 0.34% | 0.47% | 0.26% |
| **Pole Top Structures** | % replaced | 0.62% | 0.87% | 0.66% | 0.52% |
| **Conductors** | % replaced | 0.19% | 0.33% | 0.20% | 0.11% |
| **Underground Cables** | % replaced | 0.08% | 0.09% | 0.11% | 0.05% |
| **Services** | % replaced | 0.90% | 2.32% | 1.20% | 1.54% |
| **Distribution Transformers** | % replaced | 1.39% | 1.61% | 1.49% | 1.28% |
| **Zone Transformers** | Ground outdoor/indoor chamber mounted - % replaced | 0.01% | 0.01% | 0.02% | 0.01% |
| **Distribution Switchgear** | Fuses - % replaced | 6.08% | 5.94% | 6.29% | 5.27% |
| | Switches - % replaced | 1.29% | 2.27% | 2.43% | 0.72% |
| | Circuit Breakers - % replaced | 1.40% | 1.65% | 1.97% | 1.05% |
| **Zone Switchgear** | Fuses - % replaced | 18.09% | 22.86% | 24.15% | 21.69% |
| | Switches - % replaced | 1.41% | 2.20% | 2.20% | 0.66% |
| | Circuit Breakers - % replaced | 0.22% | 0.24% | 0.33% | 0.16% |
| **Public Lighting** | Luminaires - % replaced | 2.97% | 3.25% | 3.19% | 1.31% |
| | Brackets - % replaced | 0.94% | 1.17% | 0.41% | 0.47% |
| | Lamps - % replaced | 45.11% | 25.15% | 33.12% | 21.56% |
| | Poles - % replaced | 0.17% | 0.25% | 0.27% | 0.38% |
| **SCADA and Protection** | Field devices - % replaced | 3.30% | 0.88% | 1.12% | 1.53% |
| | Master station - % replaced | 49.57% | 0.85% | 3.45% | 13.10% |
| | AFLC - % replaced | 0.00% | 3.70% | 0.00% | 30.91% |
| **Communications** | Comms network assets - % replaced | 3.44% | 2.00% | 1.15% | 0.15% |
| | Comms site infrastructure - % replaced | 3.97% | 2.37% | 0.00% | 0.42% |
| | Comms linear assets - % replaced | 0.44% | 0.45% | 0.93% | 0.26% |
| **Zone Other Assets** | Current transformer - % replaced | 0.20% | 0.05% | 0.30% | 0.28% |
| | Voltage transformer - % replaced | 0.43% | 0.22% | 0.71% | 0.40% |
| | Capacitor Banks - % replaced | 0.03% | 0.09% | 0.08% | 0.00% |
| | Static VAR compensator - % replaced | 0.01% | 0.05% | 0.04% | 0.00% |

### Poles

The proportion of wood poles being staked has fallen due to Ergon Energy no longer staking natural wood poles.

### Pole Top Structures

The high proportion of pole top structures, conductors, and services replaced in 2011-12 can be attributed to the high proportion of natural disasters that affected Queensland during this period.

### Conductors

A proportion of the conductor can also be attributed to a program to replace 7/.064 HDBC High Voltage conductor.

### Services

A proportion of the services can also be attributed to a program to change all open wire services to an insulated service line.

### Distribution Switchgear

The high proportion of switches replaced during 2011-12 and 2012-13 was due to a replacement program for a specific brand of air break switches which were experiencing condition issues which impacted on safety.

### Public Lighting

The high proportion of public lighting brackets replaced during 2011-12 can be attributed to the high proportion of natural disasters that affected Queensland during this period.

### SCADA and Protection

The high proportion of Master Station replacements for 2010-11 can be attributed to upgrade programs such as the “ABB SCADA NMR4 Upgrade Project” which have begun to replace a significant number of computer server systems. It is also noted that the overall population of master station is very low, thus any impact or replacement of this system and its components will result in a high percentage outcome.

The high proportion of AFLC replacements for 2013-14 can be attributed to the 15 year life cycle of this asset since their introduction to the network between 1982 and 1984.

### Communications

Ergon Energy notes that this asset category has only been a recent addition to the AER regulatory requirements and has encountered issues in procuring asset records to formulate asset replacement counts (past and future). As many previous UbiNet projects were undertaken outside normal business processes with associated records kept on multiple systems procuring an accurate asset count is difficult to achieve. This accounts for varied estimated asset replacement counts for ‘Communication Site Infrastructure’ assets 2010-11 to 2013-14.

Overall, the varied proportions for this asset category reflect an attempt to minimise and reduce works due to the business deciding to introduce budgeting constraints, minimise project costings and finalising UbiNet projects.

**B. replacements due to other factors (and a description of those factors);**

Replacement may be required due to environmental, safety and risk mitigation requirements and these have also been included in the proportion of replacements detailed above.

Replacement of existing equipment to supply required or forecast electrical capacity of part of the network may also require an asset to be replaced to resolve the issue.

**C. additional assets due to the augmentation, extension, development of the network; and**

Additional assets due to augmentation, extension, or development of the network are determined by the modelling of the utilisation of the network and whether the Point of Exceedance (PoE) would be reached for that asset type. New assets shall not be costed under this model as any augmentation to the network would be driven by augmentation expenditure, as would an extension or development of the network be driven by operational expenditure.

**D. additional assets due to other factors (and a description of those factors).**

Additional assets may be installed due to reliability issues or due to design issues when an asset is replaced. Reliability issues may result in a line being reconductored or simple switchgear being replaced with electronically monitored switchgear.

Where assets are replaced it may require that a line is brought up to the current standard as it was built to a previous standard which does not meet current legislation.

**(b) Justification for the replacement life statistics provided (the mean and standard deviation), including:**

**(i) the methodology, data sources and assumptions used to derive the statistics;**

The methodology, data sources and assumptions used to provide the mean and standard deviation for the replacement life statistics is detailed in the Reset RIN Basis of Preparation document for regulatory template 5.2 Asset Age Profile.

Where sufficient data exists the mean is calculated from the CBRM model using the model’s expected life and then the square root of the expected life is the standard deviation.

Where the CBRM model cannot be used the SME has given the best estimate and the square root of the mean as the standard deviation.

**(ii) the relationship to historical replacement lives for that asset category; and**

The mean and standard deviations is calculated from estimates rather than actual data and assets are removed from serviced based on their actual condition. This gives an asset economic life rather than just its replacement life based on estimated values.

**(iii) Ergon Energy's views on the most appropriate probability distribution to simulate the replacement needs of that asset category, including matters such as:**

**A. the appropriateness of the normal distribution or another distribution (e.g. the Weibull distribution);**

Ergon Energy has determined that normal distribution is an acceptable methodology to simulate the replacement needs of assets. This is used where sufficient data exists as part of the CBRM methodology on the following specific assets distribution feeders, underground cables, distribution transformers, distribution reclosers, distribution regulators and ring main units.

**B. the typical age when the "wear out" phase becomes evident;**

Ergon Energy has a range of inspection and maintenance programs which have been developed to assess the risk when assets may begin to experience "wear out". However the typical age of the asset when this becomes evident is affected by environmental conditions, the assets operating environment and the design of the individual assets within each asset category, this complexity makes the prediction of imminent failure difficult to ascertain.

**C. the "skewness" of the distribution; and**

The distribution in calibrated by adjusting the mean age with the actual replacements achieved for a given year. For example, through modelling a mean year maybe calculated at approximately 43 years with a recommended replacement volume of 16 but the actual replacement level was 5 so on calibration the mean life achieved is 64 years a difference of over 20 years.

**D. the process applied to verify that the parameters are a reasonable estimate of the life for the asset category.**

Ergon Energy uses CBRM models for specific assets as detailed previously as well as condition monitoring tools and processes to identify that the parameters are a reasonable estimate of the life. Where CBRM models have not yet been developed analysis is performed based on risk assessments that consider the safety, history and performance with input from the asset SME to make reasonable estimates on economic end of life and life extension refurbishment works.

**(c) The derivation of replacement unit costs and asset lives, including any internal documentation or analysis or independent benchmarking that justifies or supports its cost data. This information must include:**

For an explanation and justification of the methodologies applied by Ergon Energy to develop unit cost estimates for asset replacement capital expenditure, refer to section 7.3 of Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary. In addition, the following response is provided.

**(i) the methodology, data sources and assumptions used to derive the cost data;**

The cost data has been calibrated against standard cost estimates which are based on a prediction of volumes multiplied by a unit cost. This is due to the uncertainty in volumes as condition based inspections having not yet occurred. Where there is certainty around the constraint, scope, location, and timing of the investment the project would go through a gated approval system where the cost estimates based on multiple standard estimates are refined at each stage.

The data sources used to derive the replacement unit costs is Ellipse Estimating and averaging of historical replacement costs.

**(ii) the possibility of double-counting costs in the estimate, and the process applied to ensure this is appropriately accounted for;**

As there is some overlap in some asset groupings, the data is developed separately for lines, distribution plant, substations and secondary systems. This data is then blended to ensure that there is no double-counting of costs. The total cost of all refurbishment and replacement is readily identifiable in Ergon Energy's ERP costing module from their chart of accounts "Activity Codes". These total costs have been allocated across all the categories reported, thus reconciling all reported costs and eliminating any possibility of double counting.

**(iii) the variability in the unit costs between individual asset replacements, and the main drivers of the variability;**

The variability in the unit costs between individual asset replacements can be due to labour costs or can be due to geographical location and travel times involved or known site conditions. Variability can also be due to extra works required due to exclusions within the standard estimate.

**(iv) the relationship of the unit cost, and its derivation, to historical replacement costs for that asset category (this should clearly differentiate and quantify any assumed cost difference due to labour/material price changes and other factors);**

The standard estimate cost is used as the unit cost which includes mobilisation cost and labour costs. The historical replacement costs based on the number of replacements and the cost of those replacements has been used in the past as an indicator before standard estimates and to ensure the standard estimate costs were as accurate as possible.

**(v) the process applied to verify that the parameter is a reasonable estimate of the unit cost for the asset category; and**

Based on information gathered from historical replacement costs comparison with the standard estimate costs have shown that once all factors have been applied to the costs the unit cost for an asset category are reasonable.

**(d) For the previous, current and forthcoming regulatory control periods, explain the drivers or factors that have changed network replacement expenditure requirements. Separately identify and quantify the relative effect of each of the following matters on network replacement expenditure requirements, where they have changed network replacement expenditure requirements:**

**(i) rules, codes, license conditions, statutory requirements;**

There were no significant legislation changes during the regulatory control period 2005 to 2010. However, during the 2010 to 2015 regulatory control period changes have been made to harmonise the Work Health and Safety laws with the introduction of the

*Queensland Work Health and Safety Act 2011* in December 2012. Changes were also made to the *Queensland Electrical Safety Code of Practice 2010* and works took effect January 2014. Both of these amendments affect Ergon Energy's compliance requirements, and have influenced Ergon Energy's forecasts for the 2015 to 2020 regulatory control period.

**(ii) internal planning and asset management approaches;**

Ergon Energy has established CBRM models for some of its assets as listed previously, where CBRM models have not yet been developed net present value analysis and risk assessments are used to make informed decisions on end of economic life replacement and life extension refurbishment works.

Ergon Energy is also committed to aligning its asset management practices with ISO 55000 principles.

Ergon Energy has plans to implement the JAM-IT tool to aid field employees to assess and collate asset condition information during maintenance routines, automating updates to Ellipse. This will improve the accuracy and housekeeping of asset records and aid in the valuation of asset condition.

**(iii) measurable asset factors that affect the need for expenditure in this category (e.g. age profiles, risk profiles, condition trend, etc.). Identify and quantify individual factors;**

Improvements have also been made to data and information systems, inspection and condition monitoring regimes and better understanding of asset failure modes and asset management processes. This has enabled Ergon Energy to make better decisions based on risk, ongoing maintenance costs, replacement costs, age as well as asset condition.

Collation and use of condition monitoring data will continue to be collected and implemented for all Ergon Energy asset classes. This information can be used to enable Ergon Energy to reassess, defer or cancel network replacement driven capital expenditure projects and improve CBRM modelling.

The improvements continuing in the AIDM project has led to joint initiative Lines and Substations Defect Classification Manuals which enhances capturing of defects and ensure that replacements are prudent. This has allowed consequential maintenance and renewal works to be packaged together to improve works efficiency and reduce costs.

These improvements have been reflected in the unit costs and the quantities in the next regulatory control period.

**(iv) the external factors that can be forecast and the outcome measured (e.g. demand growth, customer numbers) that affect the need for expenditure in this category. Identify and quantify individual factors, covering the forecasts and the outcome (external factors to be discussed here do not relate to changing obligations which are covered in paragraph 4);**

Over the regulatory control period 2005 to 2010 the external factors that affected the need for expenditure include, the economic boom in Queensland prior to the global financial crisis which experienced strong mining growth and residential property growth. This led to increased expenditure to meet customer connection requirements. Significant weather events such as Cyclone recovery works led to the reprioritisation of resources and expenditure. An increase in customer initiated capital works (CICW) and resource limitations led to the decision to defer some replacement works in response to upward pressures on customer prices.

During the regulatory control period 2010 to 2015 the works that were deferred during the previous regulatory control period led to an increase in renewal expenditure to maintain failure rates within acceptable levels. This included increased conductor, cables, services, pole top and transformer renewal allowances, a number of subtransmission line rebuilds and increased earthing remediation allowance. Major restoration works required after Tropical Cyclones Anthony, Yasi and Oswald and flooding around Bundaberg and Southern regions of Ergon Energy led to the reprioritisation of resources and expenditure whilst still trying to complete and/or reprioritise other programs to maintain and/or replace network assets. The replacement program for 7/.064 HDBC HV conductors was accelerated due to high risk safety issues and the replacement program for a specific brand of Air Break switches was accelerated due to threats to minimum service standards. However more focussed risk assessment and improved defect identification has reduced expenditure for various programs. Improved condition data for subtransmission feeder assets has enabled Ergon Energy to reassess the need to rebuild some subtransmission feeders and instead prioritise less expensive refurbishments via pole top replacement as more prudent and efficient.

The external factors that are forecast to affect the upcoming 2015 to 2020 regulatory control period include changes to compliance requirements under the different legislation (detailed above) and replacement of assets reaching end of useful life. In addition, safety requirements driven by the risk of asset failure such as hard drawn bare copper (HDBC) HV conductor replacement program shall also impact upon the regulatory period.

**(v) technology/solutions to address needs, covering:**

**A. network; and**

### Integrated Network Operations Centre

Modern distribution networks are increasingly installing active terminal equipment to allow for real-time monitoring and remote control. This equipment includes the control of network elements such as reclosers and switches, plus monitoring devices, which will provide real time data on network status and drive management of network assets.

### Alternative Data Acquisition Service (ADAS)

Ergon Energy has a growing need to collect data from the growing number of intelligent electronic devices (IEDs) in the field in order to understand how the distribution network is performing and apply this data to enhance network performance planning and strategies.

### Distribution Management System (DMS)

Ergon Energy has a growing need to address pressures by stakeholders to improve operational efficiency and workforce productivity; uptake of renewable generation and distributed resources; acceptance of new entrants, disruptive technologies and accommodate them within network design and power flow; participation of energy management and conservation through the administration of a Distribution Management System.

### Master Station SCADA Strategy

To build smarter, more efficient distribution grids by introducing an increase in IEDs on the network as well as more intelligent centralised control systems including master stations.

### Operational Network Security

In accommodating new technologies including smart meters, transformer monitoring and low voltage network automation, new challenges are introduced around the security of data and intelligent devices connecting to the operational network, in particular the threat of a cyber-attack.

### Regulator Remote Communications Strategy

Ergon Energy has a long term goal for all HV regulators to obtain remote communications capability for engineering access and SCADA/DMS data enabling improved and direct management of the network.

### N-1 Security Rating and instigation of Safety Net

Ergon Energy has changed from promoting the N-1 security rating criteria within its management and design of substation network which has changed the drivers and motive of project work and maintenance.

### Government Policies and Initiatives (Safety Net Measures)

The Queensland Government have reformed reliability standards as of 1 July 2014 to:

- remove the current strict network design requirements for distribution networks, increasing focus on service performance targets for supply interruptions to customers, and transition to a more cost-effective approach which takes into account the value customers place on reliable supply;
- introduce 'safety net measures' for distribution networks to protect customers from the risks of significant supply interruptions; and
- relax the current strict network design requirements for transmission networks and similarly transition to a more cost-effective approach.

The proposed ‘safety net measures’ mentioned above shall drive Ergon Energy to change its management practices, operational awareness and response to network issues.

Having recently been announced by government, Ergon Energy has not had any opportunity to fully analyse and prepare for the repercussions of this policy.

At the very least Ergon Energy foresees business changes in its management of network reliability and capacity; response to customer outages; pre-emptive maintenance; rural and remote management of assets; implementation of contingency plans and the securement of customer supply.

In addition, Ergon Energy shall need to accommodate and manage changes of the Rules including connection arrangements, customer’s power of choice and associated response time frames.

### Assets Data Acquisition (JAM-IT)

Ergon Energy has a growing need to identify, collate, analyse and report of network assets at a more granular level to improve asset management and the performance of its distribution network.

Implementation of the JAM-IT program shall assist in the collation of asset condition data by allowing onsite update of asset records allowing improved awareness of asset condition and an better informed asset management.

### Engineering Standards and Protocols

Ergon Energy shall need to address or adapt to changes of universal or local engineering standards as they arise.

This includes the potential need to convert PDH (Plesiochronous digital hierarchy) communication capable technologies utilised by tele-protection equipment (i.e. protection relays) due to the withdrawal of technical support in 2019 in favour of IP (Internet Protocol) technologies (e.g. ISC61850 Standard).

Ergon Energy shall also need to accommodate newly introduced Australian Standards such as AS4777 and its proposed inverter technologies within Ergon Energy's distribution network.

**B. Non-network.**

Ergon Energy has begun to incorporate CBRM analysis throughout many of its asset classes with expectations to apply this tool to the majority of network assets.

Incorporating this tool will assist Ergon Energy in its asset management processes and offer supporting analysis in determining prudent and efficient decisions that benefit network operations and performance as well as the customers it supplies.

**(vi) any other significant matters.**

Not applicable. The information provided in response to the above requests should at least distinguish between the asset categories defined above.

# 7. AUGMENTATION CAPITAL EXPENDITURE MODELLING

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to augex are as follows:

- 0B.01.01 Appendix B: Capital expenditure forecasts for Standard Control Services
- 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary
- 07.02.02 Distrib Network Aug Plan
- 07.02.03 Subtrans Network Aug Plan
- 07.02.04 Network Planning Process
- 07.02.05 Security Criteria
- 07.02.08 Energy Demand Forecast Method
- 07.02.09 Load Forecast System Max Demand Reference Document
- 07.02.10 Load Forecast Spatial Max Demand Reference Document.

**7.1 Any instructions in this Notice relating to the augex model must be read in conjunction with the augex model guidance document available on the AER's website** (http://www.aer.gov.au/node/18864).

Ergon Energy has read the instructions in this Notice in conjunction with the AER's augex model guidance document.

**7.2 In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model:**

**(a) Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Ergon Energy must explain how it:**

**i. Prepared the maximum demand data (weather corrected at 50 per cent probability of exceedance; see Schedule 2 for further guidance) provided in the asset status regulatory templates 2.4.1 to 2.4.4, including where relevant, explanations of each of:**

### Sub-transmission lines:

In the majority of cases, the maximum demand data was drawn from those sub-transmission lines which had the relevant historical metering records. In cases where no metering data was available, estimations were made based on the substations that these lines supplied, where this was possible. Sub-transmission lines that supply customer owned substations were excluded where sufficient loading and other information was lacking. As the maximum data in the majority of cases was based on raw metering sources (albeit filtered, see below), a correction factor to adjust the demands to equivalent 50 PoE values was used. This adjustment factor was based on the ratio between the summated non-coincident demands to the estimated summated non-coincident 50 PoE demands in the Economic Benchmarking RIN. For sub-transmission lines at 66kV and below, the zone substation 50 PoE data was used to derive the correction factor. For sub-transmission lines greater than 66kV, the connection point 50 PoE data was used to derive the correction factor.

(A) The maximum demand data in the RIN template may be used to determine how close a particular line currently is to its rating. However for planning purposes, where constraints are being forecast, the demand value that will be used will be estimated from load flows utilising the 10 PoE substation forecasts of the substations that the sub-transmission lines supply in non-redundant cases. For situations where N-1 constraints need to be examined, the 50 PoE substation forecasts are utilised instead.

(B) The demand value, where it has been drawn from metering sources, was automatically filtered of abnormal conditions through statistical outlier rejection. In addition to this, those peak demands which had abnormal power factors were also removed, as abnormal power factors generally denote a metering error.

(C) For the majority of demand values, the values given are from metering/actual demands for the given year, with the aforementioned 50 PoE correction factor applied. For the remainder of the demands, the values were estimated in one of two ways. In those instances where there were no directly available demands from metering sources for both 2009-10 and 2013-14, the network topology was used to examine which substations were supplied by the sub-transmission line. The relevant summated 2009-10 or 2013-14 demands of those substations were multiplied by an average co-incident factor derived by examining the ratio of the non-coincident to coincident zone substation demands in the Economic Benchmarking RIN.

    In the instances where there was metered demand records for either the 2009-10 year or the 2013-14 year, the proportion of this metered demand to the recorded maximum demand of the terminating substation was calculated. This same proportion was used for the year which did not have valid metering data, where it was multiplied by the terminating substation maximum demand for the required year to estimate the sub-transmission line loading for that year. For instance, if for 2013-14 the metering data gave a maximum demand of 50% of the terminating substation for the line, this same proportion (50%) was multiplied by the maximum demand of the terminating substation in 2009-10 to estimate the maximum sub-transmission line demand for that year.

(D) The relationship between 10 and 50 PoE demands will be the same as the substations that the sub-transmission lines supply, which is detailed in the substation section below.

### Sub-transmission substations and zone substations:

The 50 PoE corrected maximum demand data for the sub-transmission substations and zone substations were drawn from the SIFT system as discussed in Regulatory Proposal attachment 07.02.10 Load Forecasting Spatial Maximum Demand Reference Document [section 6 – Models and Methodology]. The E-SIFT system which is an input into the SIFT system creates a multivariate regression model of the maximum demand, which includes as an independent variable temperature. A Monte-Carlo analysis is performed to determine the 50 PoE historical demands based on the aforementioned model.

(A) The 50 PoE maximum demand is used in all sub-transmission substation and zone substation planning considerations

(B) The 50 PoE maximum demand is based on a multivariate regression model that is fitted to historical actual maximum demand values recorded by statistical metering devices installed within the zone substations. The maximum demands are usually the summation of metering monitoring each transformer within the substation. The historical actual maximum demand values are pre-filtered using statistical techniques and expert review to remove any switching events or anomalous operating conditions.

(C) Not applicable.

(D) The relationship of the 50 PoE values to the actual demand values varies depending on the sensitivity of the demand to temperature, and also unaccounted sources of variability captured in the error term of the multivariate model – refer to Regulatory Proposal attachment 07.02.10 Load Forecasting Spatial Maximum Demand Reference Document. The average ratio of the historical 10PoE demand to the 50PoE demand, based on the aggregated non-coincident demand at the zone substation and transmission point connection level is 1.082 and 1.078 respectively.

### HV feeders:

The actual maximum demand data was extracted from a database populated with data from statistical metering devices installed at the feeder circuit breaker. For the significant minority of cases where no such data exists, estimations of the maximum demand were made using consumption information and typical load factors. For those few cases where 2013-14 data was available and 2009-10 demands were not, an assumption was made that the demand was identical between the two years. At this stage, temperature correction is not performed at the distribution feeder level, so in order to estimate the 50 PoE temperature corrected demands, the ratio of the 50 PoE to the actual (DOPSD0209 / DOPSD0207) summated non-coincident maximum demand at the zone substation level from Ergon Energy's response to the AER's Economic Benchmarking RIN 2013-14 (2013-14 EB RIN) was used as an approximate temperature correction factor. This factor was applied globally across all distribution feeder demands.

(A) The aforementioned 50PoE temperature correction was only applied in order to meet the RESET RIN data requirements. In practice, the raw maximum demand data is utilised in normal distribution planning processes. When considering a constrained feeder the distribution planners will on occasion use historical maximum demands if they have good reason to believe that the current maximum demand occurred at less than 50 PoE temperatures.

(B) As mentioned above, the actual demand data is measured at the feeder circuit breaker. Abnormal operating conditions, such as switching events, are filtered from the raw demand data by statistical techniques and/or expert review.

(C) In the significant minority of cases where there is no metering data, the feeder maximum demand is estimated by using consumption values with an estimated load factor. In some cases, where the customer base is purely residential in nature, the demand is estimated using typical after diversity maximum demand (ADMD) values for residential customers. In some cases recloser metering is also used for segments of the feeder to either confirm or augment the estimation. For those few cases where 2013-14 data was available and 2009-10 demands were not, an assumption was made that the demand was identical between the two years

(D) As mentioned above, 10 and 50 PoE corrections are not currently made to distribution feeder demands. However, some analysis has been performed on a small sample of feeders and the demand difference between 10 and 50 PoE is on the order of 5-10%.

**Distribution transformers:**

The distribution transformer maximum demands were estimated using a specialised software package called Energy Analysis Management (EAM). The vast majority of the distribution transformers in the Ergon Energy network do not have metering and therefore demand has to be estimated. The EAM package takes those transformers and customers which do have metering and categorises these transformers depending on consumption levels and tariff types. It then creates load models for these metered points relating the consumption on different tariffs to maximum demand, dependent on the temperature which is obtained from the closest Bureau of Meteorology weather station. The maximum demand at each transformer which does not have metering can then be estimated by summating the consumption through that transformer based on the usual schedule of meter reads, the temperatures of each day within that period, and using the temperature dependent tariff load models previously constructed based on known demand data. This will give a maximum demand estimation in kW, which was converted to kVA by assuming a generic 0.9pf.

Unfortunately, the advent of significant penetration of solar tariffs on the Ergon Energy network has rendered the EAM software inaccurate from 2012-13 onwards. As such, the last reliable data-point of distribution transformer utilisation from EAM is 2011-12. The 2013-14 data in Table 2.4.4 is therefore based on estimated data. This data was estimated by first establishing a relationship between the summated maximum demand across all the distribution transformers between 2007-08 to 2011-12 and the HV feeder summated maximum summer night-time demand. These values were found to have quite a close correlation, with a linear trend R2 co-efficient of 0.6. The 2013-14 HV feeder summer night-time demand data was summated and from the derived linear trend the estimated summated maximum demand of all the distribution transformers was estimated for that year. The 2011-12 maximum distribution transformer demands (and therefore utilisations) from EAM were globally scaled so that their summation equalled that estimate derived from the aforementioned linear relationship. The ratio of the 50 PoE to the actual (DOPSD0209 / DOPSD0207) summated non-coincident maximum demand at the zone substation level from the 2013-14 EB RIN was used as an approximate temperature correction factor and applied to the estimated distribution transformer demands.

(A) Historically planning has not been performed at the distribution transformer level, with all distribution transformer augmentations being performed on an ad-hoc basis, due to a myriad of reasons such as power quality complaints and solar voltage rise issues. The planned distribution transformer expenditure for the next AER period is based on historical expenditure in this area of the network and is not based on the maximum demands generated by the aforementioned process.

(B) Only a very small number of the distribution transformer maximum demands extracted from the EAM system would be based on the metering data, with the remainder based on estimations and modelling.

(C) The estimation process from the EAM package was explained above. No extensive validation process has been performed on this data with respect to the maximum demand estimations on individual distribution transformers; however the summated estimated load profiles of all customers and transformers have been shown to be able to replicate the measured feeder load with a good level of accuracy.

(D) As stated previously, only the non-temperature corrected estimated maximum demands were available from the EAM package. It is unknown how the 50 PoE temperature corrected maximum demands are related to the 10 PoE values at the distribution transformer level, however it is likely to be on the same order as that observed on distribution feeders i.e. between 5 and 10%.

**ii. Determined the rating data provided in the asset status regulatory templates 2.4.1 to 2.4.4, including where relevant:**

### Sub-transmission lines:

The 2013-14 sub-transmission line ratings were extracted from the Ergon Energy developed 2014 Sub-transmission Feeder Database (SFD). This database analyses the limiting line section on a sub-transmission feeder to return the equivalent rating of the sub-transmission feeder based on the six rating periods as described in section 7.4 of Regulatory Proposal attachment 07.02.04 Network Planning Process. The overhead ratings database that the SFD draws from contains the geo-location of all OH line segments within Ergon Energy and this allows the automated calculation of ratings based on weather parameters (ambient temperature, wind speed) in the eight designated Ergon Energy climate zones.

In the occasional case of where a sub-transmission line was missing from the SFD, manual examination of Ergon Energy's GIS or an expert populated DINIS load flow model of the sub-transmission line was consulted to determine the limiting line type. This line type was then input to a static line ratings calculator to determine the rating of the line. Expert judgement was used to estimate the operating temperature of the line in order to complete the rating calculation, but generally it was assumed that older rural lines had an operating temperature of 50 degrees and older urban lines had an operating temperature of 60 degrees (historical standard design practices). For new lines, it was assumed the operating temperature was 75 degrees, which is the current standard design practice.

The 2009-10 sub-transmission line ratings were not derived from an existing SFD as at that time no SFD was in existence. In addition to this, the 2009/10 line rating data that does exist is of poor quality. Therefore, the 2009-10 rating data is assumed to be equal to the 2013-14 rating data unless there has been an historical upgrade project performed on the given line – in such cases, the 2013-14 ratings minus the identified added capacity were used. In the few instances where a given sub-transmission line rating was missing from the SFD, manual examination of load flow models with known conductor types based on planning knowledge and a ratings calculator was used to determine the rating.

The ratings entered into the Reset RIN template were the minimum ratings for those rating seasons which resulted in the highest utilisation. Each sub-transmission line has its own unique identifier, even when such transmission lines share identical poles in a double circuit construction. Therefore, there are no "N-1 ratings" that can be entered and these values have been set to zero in the template.

(A) The rating assumptions used for the sub-transmission line were the standard assumptions for OH line ratings in Ergon Energy as detailed in section 7.4 of Regulatory Proposal attachment 07.02.04 Network Planning Process. In a minority of cases underground cables were present in the sub-transmission line – in those cases it was assumed that the OH line component was the limiting rating due to insufficient data to make an informed UG rating calculation.

(B) The ratings entered in the RIN template in the majority of cases would be used in planning the network. However, in many cases the rated operating temperature of the OH lines is unknown and in such cases the default operating temperature in the ratings database is assumed to be 50 degrees, see section 7.4 of Regulatory Proposal attachment 07.02.04 Network Planning Process. When a line is approaching constraint levels, often a survey of the line is performed to determine the actual operating temperature and therefore a rating based on that temperature would be used in the normal planning process.

### Sub-transmission substations and zone substations:

The ratings data for the substations was extracted from a number of sources. The name plate total and the normal cyclic total were extracted from the SIFT database which stores all of the transformer ratings data for the current network (2013-14). The transformer ratings themselves were calculated according to the methodology outlined in section 7.3.1 of Regulatory Proposal attachment 07.02.04 Network Planning Process and take into account, where available, transformer oil condition tests. The transformer ONAN total was extracted from a database called Substation Contingency Asset Management System (SCAMS) which contains a record, where available, of the various nameplate ratings depending on the cooling method. For the 2013-14 data, where ONAN data was not available or was clearly incorrect, the total ONAN rating was set equal to the total nameplate rating. No 2009-10 ONAN data was available, however if there was no change in the nameplate rating between 2009/10 to 2013-14, it was assumed that the current ONAN values from SCAMS were the same in 2009-10. If the nameplate ratings were different between the two years due to an upgrade project, the 2009/10 ONAN was set to the 2009-10 nameplate rating. In cases where no ONAN data was available, or a clear data error was found in the SCAMS database, the ONAN value was set to be identical to the nameplate rating. Also, in a few cases where errors were encountered for the nameplate ratings, the nameplate ratings were set to be equal to the Tx NCC values from SIFT.

The substation NCC rating was determined by manually examining substation ratings reports, which take into account not only the transformer ratings but also all the other components within the transformer bay, such as transformer cable ratings, cable boxes, bushing ratings, CTs etc., see section 7.3 of Regulatory Proposal attachment 07.02.04 Network Planning Process. These substation ratings reports do not cover all the substations within Ergon Energy, and some of them were quite dated. However, the historical project list was searched for augmentation projects which addressed these limitations. In those instances where the limitation had been corrected or no comprehensive rating reports existed, the substation NCC rating was assumed to be the sum of the transformer NCC ratings. If no such corrective project could be found, it was assumed that the substation NCC rating given in the ratings report was valid and this was used.

The N-1 emergency ratings were calculated by summating the Long Term Emergency Cyclic (LTEC) ratings of all the transformer bays and subtracting the highest rated bay element from this summation. In the cases where a valid substation ratings report was available, the limiting rating of the bay specified in the given report was used, otherwise the transformer LTEC ratings were utilised for this calculation from SIFT.

(A) See above

(B) For single transformer substations, the substation NCC rating would be used to determine augmentation timings. For substations with more than two transformers, the N-1 Emergency (or LTEC) rating would be used to determine the energy at risk during a contingency of a single transformer bay.

**HV feeders:**

The ratings for the HV feeders is based on two components comprising the trunk section of the feeder, the underground exit cable rating leaving the substation and the first section of overhead line. In Ergon Energy, the operational rating is different from the thermal rating only for feeders designated as being in an Urban environment, with sufficient transfer capacity between adjacent feeders. In such instances, the operational ratings are 75% of the thermal rating to maintain a 4-into-3 capability.

(A) For the overhead line ratings of the trunk section of the feeder, the 2013-14 thermal rating was calculated according to the OH line rating methodology detailed in section 7.4 of Regulatory Proposal attachment 07.02.04 Network Planning Process, utilising the new BOM rating criteria, with 8 special weather zones in the Ergon Energy area. The 2009-10 OH thermal rating was calculated using rating information extracted from the 2009-10 distribution feeder database (DFD) and as such was calculated previously using an older rating methodology called “NU-02”. This rating methodology split Ergon Energy’s supply region into different weather regions compared to the current BOM methodology, and had different, and less accurate, assumptions regarding wind speeds.

    The underground exit cable ratings were common to both the 2009-10 and 2013-14 years. In some cases, the underground cable ratings were calculated by detailed CYMCAP (cable ampacity) rating analysis. However, in the majority of cases where such details were unknown, the typical ratings assumptions were as follows:

    - 30 degrees C ground temperature
    - Ducted installation
    - Solid bonding
    - One of two cables in the vicinity that are buried 300mm apart
    - Ground thermal resistivity of 2$^{o}$C.m/W

On occasion, based on expert judgement and details collected about the UG cable site (but falling short of a full CYMCAP analysis), one or more of the above assumptions were altered i.e. more cables were known to be in the vicinity, cable separations were known to be different, soil thermal resistivity was known to be greater or lesser than 2$^{o}$C.m/W etc.

(B) In the case of HV feeders designated to be in an Urban environment, the operational rating given in the RIN template is used. For HV feeders designated to be in a rural environment without sufficient inter-tie capability between adjacent feeders, feeders are designated as constrained and in need of augmentation when the load reaches 90% of the thermal rating. This limit allows a “buffer” against overload events that could occur in 10 PoE temperature events.

### Distribution transformers:

The NCC ratings of the distribution transformer data was calculated according to section 7.6 of Regulatory Proposal attachment 07.02.04 Network Planning Process. Namely, the distribution transformer fleet was categorised into two classes – Domestic outdoor and Commercial outdoor with NCC rating factors of 1.35 and 1.15 respectively. These factors were multiplied by the transformer nameplate ratings to arrive at the NCC ratings. The domestic and commercial categorisations were determined by examining the total consumption values of the respective residential and commercial tariffs consumed through each transformer. Those transformers which had higher residential tariff consumptions were designated “Domestic outdoor” and vice-versa for those transformers which were designated “Commercial outdoor”.

(A) Despite there being some commercial indoor distribution transformers within the population analysed for the Reset RIN, it was assumed that all commercial transformers were outdoor due to the difficulty of determining what transformers were indoor and what were not, given the total numbers. The NCC rating factors were calculated based on 2012-13 consumption values, and it is assumed that these consumption values were indicative of the transformer type for both the 2009-10 and 2013-14 years.

Because of known data problems within the EAM data set, it was assumed that the 2005-06 to 2013-14 EB RIN estimation of the historical summation of nameplate ratings of distribution transformers was the more accurate benchmark as these figures were drawn directly from the corporate data repository. Therefore, for both the 2009-10 and 2013-14 years the individual capacities/ratings were multiplied by a scaling factor in order to reconcile the EAM data set with the RIN information. This was performed prior to the application of the NCC rating factors, as the EB RIN summation was based on the nameplate ratings.

(B) As mentioned previously, specified plans for upgrading overloaded distribution transformers, based on deemed maximum demands from EAM, is not currently undertaken. However, in those reactive instances were a transformer is suspected or confirmed to be overloaded; the NCC rating outlined above is used.

**iii. Determined the growth rate data provided in the asset status regulatory templates 2.4.1 to 2.4.4. This should clearly indicate how these rates have been**

**derived from maximum demand forecasts or other load forecasts available to Ergon Energy.**

### Sub-transmission lines:

Load flows were performed on the majority of sub-transmission lines from 2014-15 to 2018-19 using the 10 PoE substation forecasts from the SIFT forecasting system for the DAPR. These automated load flows were performed for every half hour over a simulated day, with the average peak load profile of each substation loaded into the model. This gave estimated, forecast maximum demands for all of the sub-transmission lines over the forecast period, at 10 PoE levels. The 2018-19 demand was adjusted down to 50 PoE levels by the ratio between the 10 PoE and 50 PoE levels given in the zone substation and connection point tables in the Economic Benchmarking RIN. For lines at 66kV and lower, the zone substation values were used and for lines greater than 66kV the connection point values were used. While the ST line forecast via this method only extends to 2018-19 instead of 2019-20, it was assumed that this would still be an accurate estimate of the average growth rate over the 2013-14 to 2019-20 period. The 2013-14 to 2018-19 version of equation

$\boldsymbol{GR} = \left( \left( \boldsymbol{MD_{19/20}} / \boldsymbol{MD_{13/14}} \right)^{\frac{\mathbf{1}}{\mathbf{2020-2014}}} - \mathbf{1} \right) * \mathbf{100}$ **(1)** was used to calculate the average growth rate over this period.

In cases where no load flow information existed, an average growth rate was derived from available information for feeders >66kV and for feeders less than or equal to 66kV. This average growth rate was used in place of the missing information.

### Sub-transmission substations and zone substations:

The 2013-14 to 2019-20 growth rate for the substations was calculated using the historical 2013-14 50 PoE adjusted demand and the forecast 2019-20 50 PoE demand from the SIFT forecasting system. Details about this forecasting system can be found in Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document. The average annual growth rate was calculated using the following compound annual growth rate formula:

$$\boldsymbol{GR} = \left( \left( \boldsymbol{MD_{19/20}} / \boldsymbol{MD_{13/14}} \right)^{\frac{\mathbf{1}}{\mathbf{2020-2014}}} - \mathbf{1} \right) * \mathbf{100}\ \textbf{(1)}$$

### HV feeders:

HV feeder growth rates were developed based on 2013-14 maximum demands and projected 2019-20 maximum demands. The demand projections were based on a distribution feeder level forecasting process. Because of the volatility of demand at the distribution feeder level, and the sensitivity to new customer connections, in many cases the engineering judgement of the planning engineers was used to set the growth rates. However, a general rule was applied in many cases, being:

- For evening peaking/residential customer dominated feeders, the growth rate between 2013-14 and 2019-20 was set to be equal to the historical trend of residential customer number growth

- For day-time peaking/commercial customer dominated feeders, the growth rate between 203-14 and 2019-20 was set to be equal to the zone substation forecast growth rate that supplies the feeder in question.

The reason for the differentiation between these two feeder types was due to the fact that on commercial dominated feeders a small number of residential customers could overwhelm the commercial customer trend despite the commercial load of these customers being well in excess of the residential load. In such cases, the zone substation forecast growth rate was the next best estimate of the feeder growth.

After the projection of the demands out to 2019-20 was made, equation

$\boldsymbol{GR} = \left( \left( \boldsymbol{MD_{19/20}} / \boldsymbol{MD_{13/14}} \right)^{\frac{\mathbf{1}}{\mathbf{2020-2014}}} - \mathbf{1} \right) * \mathbf{100}$ **(1)** was used to determine the average annual growth rate.

### Distribution transformers:

The distribution transformer growth rates were set to be equal to the relevant HV feeder growth rates (for Urban, Short rural and Long rural) due to the aforementioned relationship between the summated HV feeder demands and the summated distribution transformer level demands.

**(b) In relation to the capex-capacity regulatory template 2.4.6, Ergon Energy must explain:**

**i. the types of cost and activities covered. Clearly indicate what non-field analysis and management costs (i.e. direct overheads) are included in the capex and what proportion of capex these cost types represent;**

For a specified investment, Ergon Energy develops a cost estimate for all projects in support of a business case, when there is certainty around the constraint, scope, location and timing of the investment. The cost estimate is developed (within the Ellipse ERP) itemised via labour, materials, equipment and other resources required to deliver the project's defined scope of work.

Ergon's Standard estimates are based on "Ergon Energy standard designs", and are used as a template for the strategic estimates. This provides the estimate structure and phases, based on a design and particular assumptions. It contains all the required Products and Compatible Units (CUs) for the labour, materials and contract costs.

Non-field analysis and management costs (including all project management and support, but no design in 'non-field') are built into the Standard Estimate. On analysis of a sample of specified Augmentation Projects it was determined that overall these costs represent approximately 10% of total capital costs.

Effectively standard estimates are templates and are modified as required to accommodate the specific requirements of the investment. As a specified project progresses it moves through five different phases of Ergon Energy's Project Management process, where the estimate is updated according to the project scope and varies according to the project requirements.

**ii. how it determined and allocated actual capex and capacity to each of the segment groups, covering:**

### NSP-Initiated & Capacity-Related Augmentation – Actual capex:

The expenditure provided in this category is in terms of the 'as incurred' costs. Unit costs provided in Table 2.4.5 are in terms of the 'as commissioned' costs, as per the requirements outlined in the November 2013 AER augmentation model handbook, with no threshold of immateriality.

### For sub-transmission lines, the actual Capex is sourced directly from Table 2.3.4.

For sub-transmission substations and zone substations, the actual capex is based on the values in Table 2.3.4. These figures were separated into substation types (Sub-transmission, Zone) based on the proportion of projects associated with each substation type for the relevant period.

For HV feeders and distribution transformers, the actual capex is based on the values in Table 2.3.4. These figures were separated into network segment types (Urban, Short rural, Long rural) based on the proportion of projects associated with each network segment type for the relevant period.

### Customer-Initiated & Capacity-Related Augmentation – Actual capex:

For sub-transmission lines, sub-transmission substations and zone substations, no expenditure has occurred in these categories via customer-initiated & capacity-related augmentation projects.

For HV feeders and distribution transformers, the actual Capex is based on the figures given in Table 2.5.2. These values were then reduced to be in line with the capacity related shared asset component of the expenditure. These figures were separates into network segment types (Urban, Short rural, Long rural) using similar proportional distribution as was used for NSP-initiated & capacity-related augmentation capex.

### Total – Actual capex:

The capex values for this category were calculated as the sum of the actual NSP-initiated & capacity-related augmentation capex and the actual customer-initiated & capacity-related augmentation capex values.

### NSP-Initiated & Capacity-Related Augmentation – Actual capacity:

For the HV lines, sub-transmission substation, zone substation and sub-transmission lines allocations, first a report was run on historical projects which included expenditure, dates and project descriptions. A manual search was performed on these projects to determine which of these high level categories the projects belonged. Based on the project descriptions, those projects which were not peak demand related were excluded based on the augmentation definition for the Augex model.

More detailed consideration of the different categories is given below.

### Sub-transmission lines:

All those projects which were clearly demand related sub-transmission line projects were included in this category, such as:

- new sub-transmission lines
- re-conductoring existing sub-transmission lines
- increasing line design temperatures
- additional bus/bays installed to cater for the connection of new lines
- sub-transmission feeder ties to enable contingency transfers

Line easement acquisition projects were also included as these, while not directly adding capacity, were considered to be necessary pre-conditions for the development of new lines. Those projects which were deemed to directly increase the capacity of the network had this additional capacity added determined by planning staff.

The vast majority all of the projects assigned to this category belong to the internal C2040 – Augmentation activity code, however projects in the C2030 – Reliability Improvement and C2050 – Other Regulated System Capex categories were also checked as it is known that on occasion projects with demand driven drivers also fall under these categorisations. However only 2.8% of projects (by count) in this category fall into the C2030 and C2050 codes.

### Sub-transmission substations and zone substations:

All those projects which were clearly demand related sub-transmission or zone substation projects were included in these two categories, such as:

- new sub-transmission or zone substations
- transformer upgrades
- capacitor bank installations
- upgrade of transformer cables
- switchboard upgrades
- installation of transformer cooling fans.

Land acquisition projects were also included as these, while not directly adding capacity, were considered to be necessary pre-conditions for the development of new substations. Those three projects which were deemed to directly increase the capacity of the network had this additional capacity added determined by planning staff.

The vast majority all of the projects assigned to these categories belong to the internal C2040 – Augmentation activity code, however projects in the C2030 – Reliability Improvement and C2050 – Other Regulated System Capex categories were also checked as it is known that on occasion projects with demand driven drivers also fall under these categorisations. However, only 1.5% of projects (by count) in these categories fall into the C2030 and C2050 codes.

### HV feeders:

All those projects which were clearly demand related HV feeders projects were included in this category, such as:

- New feeders
- New feeder bays / circuit breakers
- Re-conductoring / re-cabling
- New line and cable segments
- New / upgraded regulators
- New SWER isolators
- Feeder ties.

Because of the large number of projects allocated to this category, and the range of project types, in many cases the additional capacity could not be directly ascertained by planning staff. An estimation process was therefore used to determine the approximate additional capacity for this segment group. The estimation process involved the following:

- A common rating scheme was in place between 2008-09 to 2011-12; therefore, for those feeders with known capacity related projects occurring on them within that period, an estimate of the added capacity could be determined by examining the difference in the distribution feeder database values between those years.
- From this data, an estimation could be made for each HV feeder category of the average capacity added / project.
- This capacity added / project could then be used for any given period and number of projects.
- As not all HV feeder projects could be assigned to a given feeder, this average capacity added factor was applied to those HV feeder projects which were not able to be checked against a feeder for the actual added capacity. This allowed the estimation of the total capacity added given the number of HV feeder projects performed within a given period.
- This capacity factor was calculated for those projects which upgraded existing feeders. On top of the capacity estimated in this way, the number of additional feeders added within the given period were manually counted within each of the HV feeder categories, with an assumed added capacity for each new feeder of 6MVA, which is the minimum design capacity for new feeders.

The majority all of the projects assigned to this category belong to the internal C2040 – Augmentation activity code, however projects in the C2030 – Reliability Improvement and C2050 – Other Regulated System Capex categories were also checked as it is known that on occasion projects with demand driven drivers also fall under these categorisations. In particular, SWER projects are categorised under the C2050 code. 20% of projects (by count) in this category fall into the C2030 and C2050 codes.

### Distribution transformers:

The estimated installed capacities of the distribution transformer data in the 2013-14 EB RIN were used for the capacity added values for this category in the Reset RIN template. To obtain the total installed capacity for the given periods, dataset DPA0501 minus the cold spare capacity (DPA0503) was used. The new capacity due solely to non-customer related works was estimated by subtracting the installed customer related distribution transformer capacity, given in Table 2.5.1, from the total added capacity data from the EB RIN 2005-06 to 2013-14. The actual expenditure in this category was obtained from the values given in the 2013-14 Category Analysis RIN in Table 2.3.3.2 summed over the relevant time period.

Because of the large number of distribution transformer projects and the significant range of possible drivers for the projects, there is no way to estimate how much of this capacity has been installed due to augmentation/growth drivers. As such, this category would contain capacity added due to non-augmentation reasons such as power quality complaints. For the same reason, the total expenditure for this category will also contain non-augmentation related expenditure.

The project codes that this category's expenditure belongs to are C2010 – Load Energy Management, C2030 – Reliability Improvement, C2040 – Augmentation and C2050 – Other Regulated System Capex. Some communications related projects were excluded from the C2050 code by further filtering on sub-codes.

#### Customer-Initiated & Capacity-Related Augmentation – Actual capacity:

For sub-transmission lines, sub-transmission substations and zone substations, no additional capacity has been added via customer-initiated & capacity-related augmentation projects.

For HV feeders, to calculate the actual customer-initiated capacity added it was assumed that the relationship between capex for NSP-initiated augmentation and net capacity added for NSP-initiated augmentation for the period of 2013-15 is similar to that of customer-initiated augmentation. This relationship was compared to the capex for customer-initiated augmentation for the period 2013-15 to arrive at the net actual capacity added values for customer-initiated augmentation.

For distribution transformers, the customer-initiated capacity added values were calculated based on the added capacity figures provided in 2.5.1. These values were separated into network segment types (Urban, Short rural, Long rural) based on capex spend for the relevant period associated with each network segment type.

#### Total – Actual capacity:

The added values for this category were calculated as the sum of the actual NSP-initiated & capacity-related augmentation capacity added and the actual customer-initiated & capacity-related augmentation capacity added values.

(A) See above.

(B) See above.

**iii. how it determined and allocated estimated/forecast capex and capacity to each of the segment groups, covering:**

#### NSP-Initiated & Capacity-Related Augmentation – Estimated/forecast capex:

The expenditure provided in this category is in terms of the 'as incurred' costs. Unit costs provided in Table 2.4.5 are in terms of the 'as commissioned' costs, as per the requirements outlined in the November 2013 AER augmentation model handbook, with no threshold of immateriality.

**For sub-transmission lines, the estimated/forecast Capex figures are sourced directly from Table 2.3.4.**

For sub-transmission substations and zone substations, the estimated/forecast capex is based on the values in Table 2.3.4. These figures were separated into substation types (sub-transmission, zone) based on the proportion of projects associated with each substation type for the relevant period.

For HV feeders and distribution transformers, the estimated/forecast capex is based on the values in Table 2.3.4. These figures were separated into network segment types (Urban, Short rural, Long rural) based on the proportion of projects associated with each network segment type for the relevant period.

### Customer-Initiated & Capacity-Related Augmentation – Estimated/forecast capex:

For sub-transmission lines, sub-transmission substations and zone substations, no expenditure is forecast to occur via customer-initiated & capacity-related augmentation projects.

For HV feeders and distribution transformers, the estimated/forecast capex is based on the figures given in Table 2.5.2. These values were then reduced to be in line with the capacity-related shared asset component of the expenditure. These figures were separates into network segment types (Urban, Short rural, Long rural) using similar proportional distribution as was used for NSP-initiated & capacity-related augmentation capex.

### The Total – Estimated/forecast capex:

The capex values for this category were calculated as the sum of the estimated/forecast NSP-initiated & capacity-related augmentation capex and the estimated/forecast customer-initiated & capacity-related augmentation capex values.

### NSP-Initiated & Capacity-Related Augmentation – Estimated/forecast capacity:

For sub-transmission lines, sub-transmission substations and zone substations, the estimated/forecast capacity added was determined by the manual analysis of each project by a planning engineer and determining the increase in capacity. This was performed for Table 2.3 for the forecast information, and the data entered there was extracted and set as the capacity added in Table 2.4.6 for the sub-transmission related categories. For 2013-14, the 2013-14 CA Augex Project RIN data was used to determine the added capacity. For 2014-15, a list of projects expected to be finalised in the 2014-15 year was analysed and allocated manually to each of the relevant Augex categories. Estimation of the added capacity was also determined from this project list.

For the HV feeder category, the forecast capacity was calculated in two steps. First, all the new feeder projects planned in the next regulatory period were allocated to the relevant sub-categories (Urban, Short rural, Long rural) and multiplied by 6MVA per feeder. The non-new feeder projects were again allocated to the relevant sub-categories, and were multiplied by the relevant sub-category MVA / project averages derived via the method described in 7.2 (ii) above. Both of these values were summated to estimate the forecast added capacities. For 2013-14 and 2014-15, the same method was used – in the 2013-14 case on projects which were known to be finalised in 2013-14, and in the 2014-

15 case on feeder projects which are expected to be completed in the 2014-15 financial year.

The distribution transformer forecast capacity was calculated by using the total forecast capacities in 3.5 of the current Reset RIN. The “non-customer” related forecast added capacities was then determined by assuming the same proportion of non-customer related capacity to the total capacity determined by the process described in 7.2(ii). This non-customer related capacity was then allocated to the sub-categories (Urban, Short rural, Long rural) by the total percentage by count of distribution transformers within those categories. The same process was also performed for the 2013-14 and 2014-15 estimates.

### Customer-Initiated & Capacity-Related Augmentation – Estimated/forecast capacity:

For sub-transmission lines, sub-transmission substations and zone substations, no additional capacity is forecast to be added via customer-initiated & capacity-related augmentation projects.

The unit cost of customer-initiated augmentation is not expected to change and therefore the net capacity added for customer-initiated augmentation for 2015-16 onwards is also based on the above relationship for actual capacity from the period 2013-15. This relationship was compared to the estimated/forecast capex for customer-initiated augmentation for the period 2015-20 to arrive at the net estimated/forecast capacity added values for customer-initiated augmentation.

For distribution transformers, the estimated/forecast customer-initiated capacity added values were calculated based on the estimated/forecast added capacity figures provided in 2.5.1. These figures were separated into network segment types (Urban, Short rural, Long rural) based on estimated/forecast capex spend for the relevant period associated with each network segment type.

### Total – Actual capacity:

The added values for this category were calculated as the sum of the actual NSP-initiated & capacity-related augmentation capacity added and the actual customer-initiated & capacity-related augmentation capacity added values.

(A) See above.

(B) See above.

**(c) Describe the projects and programs Ergon Energy has allocated to the unmodelled augmentation categories in regulatory template 2.4.6, covering:**

The major types of projects that have been allocated to the unmodelled categories are:

- Miscellaneous
  - All those projects which did not fit in the categories below
- Reliability
  - New ABS, gas switches, reclosers, aged conductor replacements, not including feeder-ties
- Protection

  - Fuse installations, relays, feeder protection reviews, fault level related upgrades of conductors, SWER isolation
- Cyclone Area Reinforcement (CARE)
  - All projects under this investment category that do not have a secondary benefit of addressing existing network constraints
- Communications
  - Installation of SCADA, demand side automation, communication links, other communication infrastructure.

The allocation of projects to these categories was performed via a manual inspection of the project descriptions.

**i. the proportion of unmodelled augmentation capex due to this project or program type;**

All of the following proportions are based on the direct expenditure from 2007-08 to 2013-14 for all projects finalised in that period.

- Miscellaneous : 18.86%
- Reliability: 17.47%
- Protection: 8.78%
- CARE: 5.18%
- Communications: 49.70%.

**ii. the primary drivers of this capex, and whether in Ergon Energy's view, there is any secondary relationship to maximum demand and/or utilisation; and**

- Miscellaneous: In this category, there are no easily identifiable primary drivers, as the projects falling into this category are as diverse as pole relocations to installing air conditioning units in the control rooms of substations. A small minority of projects may have a secondary relationship to maximum demand within this category, but because of the diversity of this category these relationships cannot be elucidated.
- Reliability: The primary driver for this category is the improvement of reliability on the network. Because this category excludes feeder-ties (these are included in the modelled categories) there is no clear secondary link to demand or utilisation.
- Protection: The primary driver for this category is the improved protection against faults on the network. For a minority of projects in this category, there may be a secondary link to maximum demand, as encroachment of loading levels on existing over-current settings of relays may necessitate the installation of new protective devices or schemes. In addition to this, high maximum demand in an area may lead to the installation of new conductors or substations which in turn increase fault levels; this may result in fault-level related replacement of conductors or the necessity of installing new protective devices.
- CARE: The primary driver for this category is the improvement of reliability and network resiliency in cyclone prone areas. Those CARE projects which had a co-augmentation driver were excluded from this category and included in the modelled categories; therefore there are no secondary links with maximum demand or utilisation for this category.
- Communications: The primary driver for this category is the improvement of communication infrastructure within the network. There are no secondary maximum demand or utilisation drivers for this category.

**iii. whether the outcome of such a project or program, whether intended or not, should be an increase in the capability of the network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level.**

- Miscellaneous: As discussed above, because of the diversity of this category nothing categorical can be said about it. A small minority of projects may increase the capability of the network in some way, but because of the diversity of this category these relationships cannot be elucidated.
- Reliability: Aged conductor replacement falling in this category may in some cases improve the capacity of the trunk section of the network. The reliability levels of customers will be improved due to works in this category.
- Protection: Fault level related re-conductoring may in some cases increase the capacity of the trunk network, however the majority of re-conductoring due to fault levels is generally on non-trunk spur sections of the network. Improved fault reach levels due to the installation of additional protective devices on the network may allow over-current levels on other protective devices to be increased, thereby allowing a high utilisation on a particular feeder.
- CARE: CARE projects often underground portions of the network and in some cases the new underground cables may have higher capacities than the overhead network they replace.
- Communications: There is no increase in the capacity of the network due to communications expenditure.

**(d) Separately for each network segment that Ergon Energy defined in the model segment data regulatory template 2.4.5:**

**i. Describe the network segment, including:**

In addition to the AER defined segment groups, for the sub-transmission lines, sub-transmission substations, zone substations and HV feeders (Urban, Short rural and Long rural), two additional sub-groups for each were defined – high growth and low growth.

(A) The high growth sub-categories were defined by those items with average annual growth rates > 0, and the low growth sub-categories were defined by those items with average annual growth rates <= 0.

(B) Over the historical period that was used to calibrate the Augex model parameters, the average segment demand across most categories was declining, resulting in average near-zero or negative growth rates. Because the Augex model is based on a Repex understanding of augmentation, zero or negative growth results in no augmentation being required according to the model. This is the case even for items in the network which are overloaded and continue to be even in the presence of zero or slightly negative growth. As such, in order to allow the Augex model to produce at least some augmentation expenditure and allow the calibration of relevant parameters, for the sub-transmission lines, sub-transmission substations, zone substations and HV feeders two additional sub-categories were defined – high growth and low growth. The presence of a high growth category enabled proper calibration of model variables such as the capacity factor, which could then be applied to the low growth category.

For the distribution transformers, when calculating the Augex model parameters, again high growth and low growth splits were made, as the median historical growth rate was negative overall between 2009-10 and 2013-14. However, as discussed in 7.2 (a)(iii), the future growth rates were universally positive across all distribution transformers, as the 2019-20 demands were simply the multiplication of the 2013-14 demands by the distribution feeder median growth rate, which is positive, via the aforementioned linear trend between these two datasets. As such, while the parameters for distribution transformers were derived by splitting historical demands, capacities, growth rates etc. into high and low growth categories, for the future there is no possible high growth – low growth split, and therefore there are no high growth and low growth sub-categories for distribution transformers in the RIN template.

**ii. Explain the utilisation threshold statistics provided (i.e. the mean and standard deviation), including:**

### Sub-transmission lines – high growth, low growth

(A) The sub-transmission line utilisation statistics were calculated by sampling from sub-transmission line projects which involved an upgrade of existing lines. Unfortunately, it is not possible to sample from new sub-transmission line projects as there is no easily definable existing utilisation level to sample. The utilisation threshold sample of a given upgrade project was derived by determining the maximum demand for the year that the project was finalised in, and dividing by the 2009-10 rating (the pre-upgrade rating). The load at the time of project finalisation was adjusted to 50 PoE levels using the aforementioned method in (a)(i).

Ideally, the utilisation threshold statistics for sub-transmission lines could be broken up into the high growth and low growth sub-categories, as is the case for the HV feeders described below. However the small number of valid samples (7 in total), precludes this further division. Therefore, the utilisation threshold statistics are shared against the high growth and low growth sub-categories.

(B) The historical planning criteria for sub-transmission lines was based on the magnitude of the load supplied. Loads greater than 15MVA (50 PoE) required N-1 line capacity, whereas loads less than 15MVA (10 PoE) only required N capacity (with varying restoration time requirements). As such, given that the sample size was insufficient to split the sub-transmission line category into further sub-segments, the utilisation threshold statistics contains samples from both of these categories. Therefore, it should be expected that the mean utilisation threshold should be somewhere in between 50% and 100%, dependent on the proportion of lines that would be upgraded in either an N-1 or N regime.

The utilisation threshold mean of 65% given in the RIN template for this category agrees with this somewhat broad expectation. A slightly more specific estimation may be performed in an approximate manner by examining those feeders with 2010 50 PoE corrected loads. A weighted average of the 50% N-1 utilisation threshold and the 92% (10 PoE to 50 PoE corrected) N threshold, based on the number of lines with loads greater than 15MVA and less than 15MVA, respectively, gives an estimation of 76% for the utilisation threshold. However, this estimation is based on the assumption that all of these feeders would be augmented at exactly the deterministic threshold, which is unrealistic and likely to be an overestimation, as important sub-transmission lines would likely be augmented at one or two years prior to a constraint emerging from steady growth.

Therefore the utilisation threshold for sub-transmission lines should be less than the 76%. Given this consideration and the lack of better data, the sample based utilisation threshold was considered the best estimation available.

(C) As mentioned above, the utilisation threshold means and standard deviations are exclusively derived from historical utilisations at the time of augmentation.

(D) Due to the small number of available samples, Ergon Energy cannot comment on the most appropriate probability distribution for the utilisation thresholds for sub-transmission lines.

(E) See (B) above.

### Sub-transmission substations and zone substations – high growth, low growth

(A) The data to determine the mean utilisation threshold was extracted two sources, the SIFT forecasting system, which also contains historical 50 PoE corrected loads, and the Ergon Energy project reporting database Ellipse. For each zone substation "upgrade only" project, the load of the substation at the time of the project finalisation was divided by the pre-upgrade substation NCC rating. This was performed for all "upgrade only" projects finalised within the 2009-10 to 2013-14 historical period respectively. As with the sub-transmission line projects above, only "upgrade only" projects were considered, as it is more complicated to isolate the utilisation of the surrounding supplies for a new substation. The samples were further split into high growth and low growth sub-categories based on the 2009-10 to 2013-14 compound annual load growth, with the mean and standard deviations calculated accordingly within the samples of these sub-categories.

For sub-transmission substations, given the relative rarity of such projects, the sample size was not sufficient to generate an accurate utilisation threshold. Given that the security criteria is well defined for sub-transmission substations (i.e. N-1, see below) it was decided that the best estimate for sub-transmission substations of the utilisation threshold mean was 50%. The standard deviation of the utilisation threshold was taken from the zone substation standard deviations. Again, due to the rarity of samples, the high growth and low growth sub-categories were set the same for the utilisation threshold statistics.

(B) The mean of the overall project samples (i.e. not split into high and low growth sub-categories) was calculated to be 59.4%. This is in line with the historical N-1 security criteria for all substations supplying load greater than 5MVA (with varying restoration response times required). As the majority of substations within Ergon Energy supply loads greater than 5MVA, it is to be expected that the overall average be around this 50% level. The 59.4% level likely represents some historically accepted risk over this 50% level given that in many cases, the N-1 capacity is only exceeded for a small fraction of the year. The variation between the utilisation thresholds for the high growth and low growth sub-categories is likely due to a small sample size and statistical variability, as there is no obvious reason as to why there would be a difference between these two sub-categories stemming from planning practices within Ergon Energy.

(C) As mentioned above, the utilisation threshold means and standard deviations are exclusively derived from historical utilisations at the time of augmentation.

(D) Ergon Energy believes that the normal distribution is appropriate for these two categories, based on examination of the aforementioned utilisation threshold samples.

(E) Because the utilisation threshold parameters were derived from actual historical projects, and the UT means comport with what Ergon Energy would expect given the security criteria levels, Ergon Energy believes this is a sufficient comparison to ensure the reasonableness of the statistics that were derived.

### HV feeders – high growth, low growth

(A) The HV feeder utilisation statistics were calculated by examining two data sources: the project reporting database which includes information such as the project expenditure, description, finalisation dates etc. and the current and historical distribution feeder databases. The project description of every project within the project reporting database was manually examined to determine if the project could be identified as an augmentation project against a certain HV feeder. If the project finalisation date was within the historical calibration period (2009-10 to 2013-14), the distribution feeder database entry for the given feeder corresponding to the finalisation year was examined, and the historical utilisation of the feeder at that time was recorded.

Not every project which was categorised as belonging to the HV feeder category was able to be clearly identified against a feeder within the network, due to the project descriptions and their historical nature and number. However, 67% of all projects categorised at the HV feeder level were able to be assigned to a particular HV feeder. These projects and their subsequent utilisation values at the time of finalisation constituted the samples in order to estimate the utilisation threshold statistics.

These projects and feeders were additionally categorised into the feeder type (i.e. Urban, Short rural and Long rural) and whether they were historically high growth or low growth over the historical period (2009-10 to 2013-14). From these samples, an estimate of the mean and standard deviation was possible for all of the six categories within the HV feeder segment group.

(B) Table 2 below shows the mean of the utilisation threshold for each of the HV feeder categories obtained from the aforementioned samples:

**Table 2** Utilisation threshold means for HV feeder categories

| HV feeder categories | Utilisation threshold mean (%) |
|---|---|
| Urban-HG | 71.0% |

| | |
|---|---|
| Urban-LG | 71.1% |
| Short rural-HG | 55.4% |
| Short rural-LG | 60.8% |
| Long rural-HG | 42.9% |
| Long rural-LG | 54.7% |

There is little difference between the Urban-HG (high growth) and Urban-LG (low growth) categories. For Urban feeders, the historical planning utilisation thresholds prior to approximately 2011 was a 3-into-2 or 66% planning limit to enable load transfers. Post 2011 this historical planning utilisation threshold was shifted to a less conservative 4-into-3 or 75% planning limit. As the project samples come from a historical period which spans both of these planning limits, an approximate average between 66% and 75% should be expected, and this corresponds with the mean derived from the samples.

For the Short rural high growth and low growth categories, a lower average utilisation threshold mean can be observed than the Urban categories. For the Urban categories, very few voltage related projects are present in the samples, and therefore the UT mean for Urban is purely capacity related. Alternatively, the Short rural categories would feature an admixture of feeders which are still within the Urban inter-tie zone, and therefore are planned according to the 66% or 75% levels, and feeders which are experiencing voltage constraints and are augmented by that driver. A lower utilisation threshold for the Short rural categories is therefore to be expected, though it should be at levels greater than Long rural which is even more predominated by voltage constraint projects. This is what is observed from the samples.

Finally, a still lower utilisation threshold is expected for the Long rural categories, and this is observed. For the Short and Long rural categories there is an observed difference in mean thresholds between the high growth and low growth sub-categories. This can be understood by considering that, on average, those feeders which may not be growing strongly will still be augmented if they are currently experiencing constraints (irrespective of growth), and the higher the utilisation threshold the higher the likelihood of an existing constraint.

(C) As mentioned above, the utilisation threshold means and standard deviations are exclusively derived from historical utilisations at the time of augmentation.

(D) The most apt Urban feeder distribution is probably the normal distribution, though the spread of the utilisation threshold values of the historical projects is broader than that described by the normal distribution maximum likelihood estimate of the standard deviation. The Short rural distribution of utilisation threshold values is even wider owing to the presence of voltage projects in addition to those addressing trunk section constraints. This category could potentially even be bi-modal, though this has not been investigated by Ergon Energy. Finally, the Long rural has a heavier tail than the other categories and could perhaps be better modelled by a log-normal distribution.

(E) Because the utilisation threshold parameters were derived from actual historical projects, and the UT means comport with what Ergon Energy would expect given the distribution feeder level security criteria levels and the gradual move to more voltage dominated UT thresholds the longer the feeder is, Ergon Energy believes this is a sufficient comparison to ensure the reasonableness of the statistics that were derived.

### Distribution transformers

(A) Obscure data in the distribution transformer category would not allow a sample based estimate of the utilisation threshold as was the case for the other categories. Therefore, the utilisation threshold mean was estimated by using the Augex model to calibrate. The utilisation threshold standard deviation was estimated as being the same as the average standard deviation for all the distribution feeder categories. The capacity versus utilisation array, the estimated capacity factor (see below) and the estimated growth rate were all loaded into the Augex model for each category, and the utilisation threshold mean was varied until a match was made between the additional capacity output from the model and the total estimated capacity added for each sub-category (Urban, Short rural, Long rural) for the period of 2010-11 to 2013-14 (inclusive – 2009-10 starting utilisation array year). The total estimated added capacity was calculated for the distribution transformers according to the method given in 7(b). This total capacity was split between the Urban, Short rural and Long rural categories, and subsequent high growth, low growth categories for the historical calibration, by looking at the percentage (by count) of the total distribution transformer population for each category, then multiplying this proportion by the total added capacity.

(B) As previously discussed, no planning has been dedicated in the past to address distribution transformer constraints, and therefore there is no criterion to compare against. The source of expenditure in this category is overwhelmingly reactive, in particular it is related to power quality complaints. Many power quality complaints are due to voltage issues which are exacerbated when a transformer is heavily loaded. The high utilisation threshold mean for the Urban networks, in comparison to the other categories, may be due to the generally low impedance LV networks in Urban settings leading to a general lack of voltage issues – only when the transformer becomes quite severely overloaded may there be complaints and subsequent augmentations. In contrast Short rural, and especially Long rural, LV networks generally have higher impedance values and therefore are more sensitive to voltage problems. As such, an overloaded transformer will have a higher impact on power quality and lead to augmentations at a lower level of overload compared to Urban networks.

(C) Because of the variability of project descriptions in this area, and demand estimations, this was not able to be assessed for distribution transformers.

(D) Again, because of the quality of data Ergon Energy is not able to make an informed opinion about the most appropriate probability distribution.

(E) Only a qualitative reasoning process, as given in (B) above, was able to determine the reasonableness of the utilisation threshold values.

**iii. Regarding the augmentation unit cost and capacity factor provided, provide an explanation of each of:**

### Sub-transmission lines – high growth, low growth

(A) The capacity factor was obtained by a calibration process within the supplied Augex model tool. First, the utilisation threshold statistics, the growth rates and the capacity versus utilisation array values were imported into the Augex model. The total added capacity in the historical period of 2010-11 to 2013-14 (inclusive – 2009-10 starting utilisation array year) was also calculated via the aforementioned process in 7(b).

The capacity factor in this case was calculated by performing an average over two separate methods. For the first method, total capacity added was split into the low growth and high growth sub-categories by examining the capacity added in those sub-transmission line projects which involved an upgrade of an existing line. These lines could be identified as either high growth or low growth due to existing load, as opposed to new line segments where the existing growth in the area is more difficult to attain. The percentage of the capacity added on high growth and low growth feeders was calculated at 18% and 82% respectively. The remaining capacity added (all those projects which were not upgrades to existing lines) was split into the high growth and low growth categories according to these proportions. The Augex model was then used to iterate the capacity factor until the capacity added within the model for the aforementioned historical period matched the total high growth assigned capacity added. The low growth capacity factor could not be estimated in this way as the Augex model is incapable of modelling less than zero load growth scenarios. The capacity factor arrived at via this method was 0.57.

The first method was considered to be potentially skewed by a large project, comprising of 69% of the “upgrade only” added capacities, belonging to the low growth category. As such, a secondary method was also examined in which the capacity factor was estimated by taking the average project-by-project capacity factor, again only considering “upgrade only” projects. The capacity factor for each project was calculated by dividing the added project capacity by the pre-upgrade capacity. The average of these values was calculated to be 0.82. This capacity factor was also considered to potentially not be representative, as it was only the average of the “upgrade only” projects. Therefore, the best estimate was considered to be the average between these two factors, yielding a capacity factor of 0.70. This capacity factor was shared across both the high growth and low growth categories, due to lack of data to discriminate between the two.

The unit cost values were derived by simply dividing the total expenditure by the total added capacity in the sub-transmission line category. Line route acquisitions and investigations were also included in the total expenditure, as these were considered to be a necessary pre-condition for capacity adding line building projects. In any case, the line route acquisition projects only constitute 5% of the total finalised sub-transmission line expenditure between 2009-10 and 2013-14 inclusive.

Unit costs provided in Table 2.4.5 are in terms of the ‘as commissioned’ costs, as per the requirements outlined in the November 2013 AER augmentation model handbook, with no threshold of immateriality.

(B) As discussed above, one of the capacity factor estimation methods was based directly on sampling capacity factors from projects. The average \$/MVA value derived from averaging the individual project \$/MVA values was calculated to be \$202,225/MVA, which is quite close to the value given in the RIN template.

(C) Each individual project was checked to ensure double counting did not occur. In particular, it was ensured that if a sub-transmission line project added capacity in the relevant historical period, any associated capacity added at the substation level in the form of sub-transmission line feeder bays was ignored.

(D) As above, the estimates of the capacity factor involved two different methods to attempt to achieve a reasonable estimation. The unit cost estimations were compared with the average of the project samples and these values were found to be in close agreement.

### Sub-transmission substations and zone substations – high growth, low growth

(A) The zone substation and the sub-transmission substation capacity factors were calculated utilising the Augex model. Because the low growth category, given its negative growth rate, was not capable of being analysed by the Augex model, the capacity factors were derived solely from the high growth category data. The capacity factor for the high growth data was then shared across the low growth category also. In order to estimate the capacity factor from the Augex model, first, the utilisation threshold statistics, the growth rates and the capacity versus utilisation array values were imported. The total added capacity over the chosen historical period of 2010-11 to 2013-14 (inclusive – 2009-10 starting utilisation array year), was calculated via the aforementioned process in 7(b). For the zone substations, the added capacity was then split into the high growth and low growth categories by examining "upgrade only" projects which landed in both categories. The relative proportion of these projects in each of the categories was applied to the total added zone substation capacity to estimate total high growth and low growth capacities.

Because of the lack of samples for the sub-transmission category, the total added capacity was split into the high and low growth sub-categories by looking at the proportional number of sub-transmission substations that fell into the high and low growth sub-categories based on the 2009-10 to 2013-14 average growth rates. The capacity factor was then iterated in the Augex model until it produced the high growth added capacities over the 2010-11 to 2013-14 period (inclusive). The capacity factor determined by this process is that which is presented in the RIN template.

The zone substation unit cost was determined by allocating the total project costs, for all projects finalised within the 2010-11 to 2013-14 period, to the high and low growth categories by using the 2009-10 to 2013-14 growth rates. This cost was divided by the added capacities allocated in the two high growth and low growth sub-categories to arrive at the unit cost estimate.

Because of the insufficient project numbers, the sub-transmission substation unit cost was not derived for both the high and low growth sub-categories. Rather, the total project costs for sub-transmission substations for the period 2010-11 to 2013-14 (inclusive) were summated, and then divided by the total added capacity.

Unit costs provided in Table 2.4.5 are in terms of the 'as commissioned' costs, as per the requirements outlined in the November 2013 AER augmentation model handbook, with no threshold of immateriality.

(B) Project samples were used in both the zone substation and sub-transmission substation categories to compare the capacity factors and unit costs. The comparisons between the project sample (for "upgrade only" projects) medians and the aforementioned method are given in Table 3 below.

**Table 3** Median direct sample comparison with utilised method

| Category | RIN CF | Samples CF | RIN $/MVA | Samples $/MVA |
|---|---|---|---|---|
| Zone substations | 0.68 | 0.33 | $195,885 | $139,038 |
| Sub-transmission substations | 0.47 | N/A | $159,570 | $167,840 |

No samples were available for the sub-transmission substations for "upgrade only" projects, hence the "N/A" entry. It can be seen that the unit cost comparison for sub-transmission projects between the samples and the aforementioned method are very close. There is also relatively close agreement between the samples and the aforementioned method for the zone substation unit cost. However, there is a discrepancy for the zone substations capacity factor comparison. This is likely due to the capacity factor being calculated only on the "upgrade only" projects, where the most capacity added is to be found in new substation projects – 48.5% of the total zone substation added capacity. Given this added capacity to the overall capacity base is not accounted for in the project samples, a higher value of the median sample capacity factor should not be considered unexpected.

(C) Each individual project was checked to ensure double counting did not occur. In particular, it was ensured that if a distribution or sub-transmission line project added capacity in the relevant historical period, any associated capacity added at the substation level in the form of sub-transmission line feeder bays was ignored.

(D) The process outlined above by comparing the overall value analysis, through the use of the Augex model, to the examination of the median CF and $/MVA values in the specific project analysis, ensured that the values used for these factors for the HV feeder category were reasonable estimates.

### HV feeders – high growth, low growth

(A) The capacity factor was obtained by a calibration process within the supplied Augex model tool. First, the utilisation threshold statistics, the growth rates and the capacity versus utilisation array values were imported into the Augex model for each of the aforementioned 6 HV feeder categories. The total added capacity in the historical period of 2010-11 to 2013-14 (inclusive – 2009-10 starting utilisation array year) was also calculated via the aforementioned process in 7(b). For new feeders, given that there are no existing feeder growth rates to use as means of splitting the capacity into high growth and low growth sub-categories, the total new feeder capacity added for, say, the Urban category, was spread evenly between the HG and LG sub-categories. The capacity factors for each category were then varied until the output capacity from the Augex model matched the estimated added capacity from the project data. The values arrived at in this process were those entered in the Reset RIN template for the HV feeders

It should be noted that for the Long rural category, insufficient samples of projects, which add trunk section capacity, exist to obtain accurate representation of the CF and unit cost values (7 samples compared to 18 and 27 for the Urban and Short rural categories, respectively). As such, a hybrid approach was undertaken whereby the CF and unit cost values were calculated both by the above method (using the Augex model to calibrate the CF values) and by taking a median value directly from the project samples (see (B) below). The mean value between these methods is used in the RIN template as the best approximation available.

For the Urban and Short rural categories, the unit costs were estimated in the same fashion as the Long rural category, see (B) below.

Unit costs provided in Table 2.4.5 are in terms of the ‘as commissioned’ costs, as per the requirements outlined in the November 2013 AER augmentation model handbook, with no threshold of immateriality.

(B) As previously discussed, an estimate of the total added capacity in each HV feeder category was determined via the process outlined in 7(b). This process uses historical project samples as its basis, but the capacity factor derived from this data is via the Augex model. For upgrade projects of existing feeders, a purely project based capacity factor estimate is possible and is shown for the three HV feeder categories in Table 2. The values given are the median (more robust central tendency measure) of the project, and do not include new feeder projects, as there is no relevant “existing capacity” from which to calculate the capacity factor.

**Table 4** Median direct sample based capacity factors, HV feeders

| HV feeder categories | Median CF |
|---|---|
| Urban | 0.26 |
| Short rural | 0.37 |
| Long rural | 0.43 |

The Urban CF is approximately a third of the CF derived by the full Augex model process described above for the Urban HG sub-category. However, as previously stated, the CF values in the table above do not include capacity due to new feeders.

New feeders amount to approximately 74% of all the added capacity in the Urban HG category, given the CF for Urban in the table above is calculated based on approximately 26% of the capacity, it should not be surprising that there is a difference between the two values. In the Short rural case – the CF based on upgrade projects only come out at 52.9% of the value given in the RIN template, however again new feeders account for approximately 44% of the total capacity added in this area. Again, this suggests that there should be a difference between the sample based and Augex model based estimating methods. Because the Augex model method takes into account both the new feeder and upgrade only capacities, this value is considered the best estimate available for these two sub-categories.

The Long rural sample median is approximately double that obtained via the Augex method. No new feeders were installed within the historical period chosen in the Long rural category, so the differences in this case cannot be explained by the influence of new feeders. This may be due to the small number of samples in this area, however, in the Long rural case, the best estimate was decided as the average between the AUGEX method and the sample capacity factors.

For the unit cost estimations, it was found that the sample based estimates gave consistently lower $/MVA values than the method of simply dividing the overall expenditure by the added capacities, derived by the methods shown in 7.2(b). Table 5 below shows the comparison between the sample based estimates and the direct division method. The sample based estimates were made over both high growth and low growth feeders to improve the sample size. The sample based unit cost was the weighted average between the "upgrade only" project means and the new feeder means, weighted according to the MVA contribution from each type of project on the total added capacity within the category (Urban, Short rural and Long rural).

**Table 5** Comparison of direct division method and sample based unit cost derivations

| HV feeder categories | Direct division method unit cost | Sample based unit cost |
|---|---|---|
| Urban- HG | $204,558 | $124,473 |
| Urban - LG | $173,170 | |
| Short rural - HG | $223,321 | $79,308 |
| Short rural - LG | $236,278 | |
| Long rural - HG | $759,179 | $18,967 |
| Long rural - LG | $128,316 | |

Because of the difference between the direct division and the sample unit costs, it was decided that the best estimate would be the average between the two values, which is what has been entered into the Reset RIN template. The very low value for the Long rural sub-category is likely due to a small sample size, but in the lack of more accurate data it was still used in the averaging to determine the final unit cost estimate.

(C) Double counting of capacity added and expenditure allocated was avoided by manually examining all of the projects allocated to each category. The expenditure and capacity of additional MV level feeder bays were allocated to the HV feeder category. The capacity of additional MV feeder bays were included only if no associated and matching feeder works were performed within the historical period analysed. If capacity was added in new feeder works which matched the new feeder bay expenditure, the capacity was only allocated once, not twice (i.e. not 6MVA for a new feeder project and an additional 6MVA for the new feeder bay project).

(D) The process outlined above by comparing the overall value analysis, through the use of the Augex model, to the examination of the median CF and $/MVA values in the specific project analysis, ensured that the values used for these factors for the HV feeder category were reasonable estimates.

### Distribution transformers

(A) Estimation of the capacity factor was performed differently for the distribution transformer category as opposed to the other categories due to the lack of sampling information for the utilisation threshold. Therefore, as described previously, the utilisation threshold was the calibrating or “free” variable for the distribution transformers and the capacity factor was estimated by examining the standard sizes of distribution transformers within each sub-category, Urban, Short rural and Long rural. The typical transformers used in each of the different network types are:

Urban: 63, 100, 200, 315 and 500kVA
Short rural: 10, 25, 63, 100, 200, 315kVA
Long rural: 10, 25, 63 and 100kVA

As can be seen, a distribution transformer upgrade is restricted in scope to the above typical transformer sizes. Therefore, in the historical model, a simple average of the capacity factor rising from the transition of a distribution transformer to its next highest size within its category was used as the estimate of the capacity factor. The values arrived at via this estimating process were those used in the AUGEX model and entered into the RIN template.

The unit cost was calculated by dividing the total distribution transformer expenditure by the total added capacity, with these values derived via the process outlined in 7(b). The lack of appropriate data in the distribution transformer area would not allow the breakup of the expenditure, and therefore unit cost, into the three sub-categories, Urban, Short rural and Long rural, and therefore the unit cost was shared across all three sub-categories.

(B) As discussed in (A) above, the capacity factor was calculated based on actual transformer sizes and the knowledge that in response to power quality type complaints the most common upgrade size for a distribution transformer it the next highest size. In lack of more comprehensive information about historical augmentation projects, there is no straight-forward way of comparing actual upgrade projects with either the derived capacity factor or unit cost variables.

(C) There was no identifiable possibility of double counting in the distribution transformer category, and therefore no double counting processes were used in this instance.

(D) Again, lack of appropriate data limited the options for either supplying alternative calculation processes or determining the reasonableness of the estimates.

**(e) Explain the factors Ergon Energy considers may result in different augmentation requirements for itself as compared to other NEM DNSPs. Ergon Energy should account for the degree that different augmentation requirements are driven by differences**

**i. the maximum achievable utilisation of assets for Ergon Energy:**

The largest difference that Ergon Energy would face compared to other utilities is its geographical extent. Ergon Energy has some of the longest networks in Australia, and this poses unique challenges in opposition to more compact distribution networks. In particular, this difference will express itself in the form of significant voltage related expenditure. Voltage related expenditure can be required on distribution networks even when they are significantly below the thermal rating of the trunk section of the feeder, and this can be clearly seen the declining utilisation threshold mean as one moves from the Urban HV feeder category, through the Short rural to the Long rural category. In the distribution transformer category this can also be observed, with the Long rural sub-category having the lowest utilisation threshold of the three sub-categories, it being the most susceptible LV network type to voltage issues.

Likewise, the existence of lengthy SWER networks on Ergon Energy's short and Long rural HV feeder categories will also force augmentation projects at potentially low trunk utilisation levels. SWER isolator constraints, for instance, may trigger significant expenditure to split SWER networks, upgrade isolators, install generation or other alternatives etc. even where the trunk section utilisation level is low.

**ii. the likely augmentation project and/or cost:**

Again, voltage issues are likely to produce a significant difference between the most likely or common augmentation project compared to other DNSPs. A significant amount of projects address voltage issues that aren't reflected in an increase of the trunk section capacity of a given feeder. Examples of such projects include the installation of regulators, new non-trunk line segments and also non-trunk re-conductoring. This expenditure is nevertheless rolled into the unit cost calculations, and because these projects don't contribute to trunk capacity Ergon Energy's unit cost value may be higher than other DNSPs that do not suffer from as many voltage constraints.

In addition to this, project costs will tend to be higher in Ergon Energy due to the significant distances in travel often required due to the vast network area. This will manifest itself in higher travel and accommodation costs than other DNSPs.

# 8. DEMAND AND CUSTOMER NUMBER FORECASTS

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to demand and customer numbers are as follows:

- 07.02.08 Energy Demand Forecast Method
- 07.02.09 Load Forecast System Max Demand Reference Document
- 07.02.10 Load Forecast Spatial Max Demand Reference Document
- 07.03.01 Model Doc Ergon Energy CICW Forecast Model
- 07.03.02 CICW Model Report.

## 8.1 Provide and describe the methodology used to prepare the following forecasts for the forthcoming regulatory control period:

**(a) maximum demand; and**

For the methodology used to prepare maximum demand forecasts refer to:

- Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 6 – Models and Methodology];
- Regulatory Proposal attachment 07.02.09 Load Forecasting System Maximum Demand Reference Document [section 6 – Models].

**(b) number of new connections.**

For the methodology used to prepare the number of new connections forecasts refer to:

- Regulatory Proposal attachment 07.02.08 Energy Demand Forecast Method [section 2.1.4 – Customer number data] and [section 3.8 – Produce Baseline energy and customer number forecasts].

## 8.2 Provide:

**(a) the model(s) Ergon Energy used to forecast customer numbers and maximum demand;**

For a description of the model Ergon Energy used to forecast customer numbers refer to:

- Regulatory Proposal attachment 07.02.08 Energy Demand Forecast Method [section 3.3 – Model development and forecasting process].

For a description of the models Ergon Energy used to forecast maximum demand refer to:

- Regulatory Proposal attachment 07.02.10 Load Forecasting Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 6 – Models and Methodology]; and
- Regulatory Proposal attachment 07.02.09 Load Forecasting System Maximum Demand Reference Document [section 6 – Models].

**(b) where Ergon Energy's approach to weather correction has changed, provide historically consistent weather corrected maximum demand data, as per the format in regulatory templates 5.3 and 5.4 using Ergon Energy's current approach. If any of this data is unavailable, explain why;**

Ergon Energy reports no change in its approach to weather correction. A consistent methodology has been used for all weather corrections.

**(c) for number of new connections, volume data requested in regulatory template 2.5; and**

For the number of new connections, volume data refer to:

- Regulatory Proposal attachment 07.03.01 Model Documentation Ergon Energy CICW Forecast Model [section 3 – Input Assumptions: 3.1 Customer connection volumes].

**(d) any supporting information or calculations that illustrate how information extracted from Ergon Energy forecasting model(s) reconciles to, and explains any differences from, information provided in regulatory templates 2.5, 5.3 and 5.4.**

If the request of (d) has been interpreted correctly, the Information supplied in template 2.5 is not used as an input to forecasting System Maximum Demand (regulatory template 5.3) nor Bulk Supply substations nor Zone substations (regulatory template 5.4) and as such there is nothing to reconcile. The reconciliation of substation system coincident demand forecasts supplied in template 5.4 to the system maximum demand forecasts of template 5.3 is an intrinsic component of the network demand forecasting process as built into the SIFT system Ergon Energy has commissioned.

For explanation of alignment of System and Spatial forecasts, refer to document:

- Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 11.3 - Reconciliation of spatial forecast to the system forecast]

**8.3 For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain or provide (as appropriate):**

**(a) the models used;**

The models used are discussed in the following documents:

- Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 6 – Models and Methodology]; and
- Regulatory Proposal attachment 07.02.09 Load Forecast System Maximum Demand Reference Document [section 6 – Models]
- Regulatory Proposal attachment 07.02.08 Energy Demand Forecast Method [section 3.3 – Model development and forecasting process]

- 07.03.01 Model Documentation Ergon Energy CICW Forecasting Model [section 3 – Input Assumptions: 3.1 Customer connection volumes].

**(b) a global (top-down)[1] and spatial[2] (bottom-up) demand forecast;**

Bottom up approach described in document:

- Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 6 – Models and Methodology].

Top down approach described in document:

- Regulatory Proposal attachment 07.02.09 Load Forecast System Maximum Demand Reference Document [section 6 – Models].

**(c) the inputs and assumptions used in the models (including in relation to economic growth, customer numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions);**

Refer to document:

- Regulatory Proposal attachment 07.02.09 Load Forecast System Maximum Demand Reference Document [section 7 – Data].

**(d) the weather correction methodology, how weather data has been used, and how Ergon Energy's approach to weather correction has changed over time;**

Weather correction methodology described in documents:

- Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 6.2.1 – Weather]; and
- Regulatory Proposal attachment 07.02.09 Load Forecast System Maximum Demand Reference Document [section 7.2 Weather data].

**(e) an outline of the treatment of block loads, transfers and switching within the forecasting process;**

Block load methodology described in:

- Regulatory Proposal attachment 07.02.10 Load Forecasting Spatial Maximum Demand Reference Document [section 7.5 - Block Loads data sources].

**(f) each appliance model[3] used, where used, or assumptions relating to average customer energy usage (by customer type);**

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[1] A global level forecast is the demand forecast that applies to the network service provider's entire network.
[2] A spatial forecast applies to elements of the network. For transmission network service providers (TNSPs), spatial forecasts could be at the level of connection points with distribution network service providers (DNSPs) and major customers. For DNSPs, spatial forecasts could be at the level of connection point, zone substations and/or HV feeders.

There is no specific modelling of appliance type energy usage in the Energy forecast.

**(g) how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load on the system and substations);**

System Demand forecast model is re-calibrated each year, refer to document:

- Regulatory Proposal attachment 07.02.09 Load Forecasting System Maximum Demand Reference Document [section 6 – Models].

**(h) how the resulting forecast data is consistent across forecasts provided for each network element identified in regulatory template 5.4 and system wide forecasts;**

Refer to document:

- Regulatory Proposal attachment 07.02.10 Load Forecasting Spatial Maximum Demand Reference Document for Spatial (Connection Point and Zone Substation) [section 11.3 - Reconciliation of spatial forecast to the system forecast].

**(i) how the forecasts resulting from these methods and assumptions have been used in determining the following**

**(i) capital expenditure forecasts; and**

Ergon Energy's capital expenditure forecasts are prepared having regard to demand and customer number forecasts, with details provided in the following documents:

- Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary [section 3.5 Demand Forecasting]; and
- Regulatory Proposal attachment 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary [section 7.2 – Capital Expenditure criteria].

**(ii) operating and maintenance expenditure forecasts.**

Ergon Energy's operating and maintenance expenditure forecasts are prepared having regard to demand and customer number forecasts, with details provided in the following document:

- 06.01.02 System Related Operating Expenditure Summary [section 3.4 – Demand Management].

**(j) whether Ergon Energy used the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal;**

Ergon Energy provides Transmission-Distribution Connection Point peak demand and energy forecasts to the Transmission Network Service Provider (TNSP) annually as required by the Rules Schedule 5.7, and by the TNSP-DNSP connection agreement.

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[3] A NSP may incorporate an appliance model in its demand forecasting method to account for the effects of the uptake of appliances (such as air-conditioners) on maximum demand.

Regular joint planning meetings are conducted with the TNSP where the latest forecasts are available.

The latest forecasts for Transmission connection points and other points of the Ergon Energy network are made available to the TNSP on request.

**(k) whether Ergon Energy forecasts both coincident and non-coincident maximum demand at the feeder, connection point, subtransmission substation and zone substation level, and how these forecasts reconcile with the system level forecasts (including how various assumptions that are allowed for at the system level relate to the network level forecasts);**

The following Regulatory Proposal attachment provides detailed information on the models and methodologies applied by Ergon Energy to produce the forecasts and explain how the coincident maximum demand forecast reconciles with the system level forecasts.

Refer to Regulatory Proposal attachment 07.02.10 Load Forecast Spatial Maximum Demand Reference Document (Connection Point and Zone Substation) [section 6 – Models and Methodology].

**(l) whether Ergon Energy records historic maximum demand in MW, MVA or both;**

At individual asset level Ergon Energy records historic maximum demand in MW and MVAr, from which MVA can be calculated.

**(m) the probability of exceedance that Ergon Energy uses in network planning;**

Refer to Regulatory Proposal attachment 07.02.04 Network Planning Process (at page 13).

**(n) the contingency planning process, in particular the process used to assess high system demand;**

Refer to Regulatory Proposal attachment 07.02.04 Network Planning Process document (page 65 and page 89).

**(o) how risk is managed across the network, particularly in relation to load sharing across network elements and non-network solutions to peak demand events;**

Refer to Regulatory Proposal attachment 07.02.04 Network Planning Process (at pages 89 to 90).

**(p) whether and how the maximum demand forecasts underlying the regulatory proposal reconcile with any demand information or related planning statements published by AEMO, as well as forecasts produced by any transmission network service providers connected to Ergon Energy's network;**

AEMO's forecast is for the Queensland NEM pool total, of which Ergon Energy is only one participant. Ergon Energy does not have any formal reconciliation process with AEMO's forecasts.

Ergon Energy undertakes joint planning with the TNSP as required under the Rules, and provides connection point Demand and Energy forecasts per Schedule 5.7 of the Rules, and as required by the TNSP/ DNSP connection agreement. Ergon Energy incorporates feedback from Powerlink as part of this process.

**(q) how the normal and emergency ratings are used in determining capacity for individual zone substations and sub-transmission lines;**

Refer to Regulatory Proposal attachment 07.02.04 Network Planning Process (at pages 44 to 45 and pages 60 to 61).

**(r) where Ergon Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder:**

For general information regarding the distribution planning process addressing all sections (r) (i to vi) refer to Regulatory Proposal attachment 07.02.04 Network Planning Process (at pages 78 to 159)

**(i) for each feeder from the zone substation that is the connecting zone substation for the relevant HV feeder, and any other feeders that the relevant HV feeder can transfer load to or from:**

**A. assumed future load transfers between feeders;**
**B. assumed feeder underlying load growth rates (exclusive of transfers and specific customer developments); and**
**C. assumed block loads, and associated demand assumptions;**

**(ii) existing embedded generation capacity, and associated assumptions on the impact on demand levels;**
**(iii) assumed future embedded generation capacity, and associated assumptions on the impact on demand levels;**
**(iv) existing non-network solutions, and the associated assumptions on the impact on demand levels;**
**(v) assumed future non-network solutions, and associated assumptions on the impact on demand levels; and**
**(vi) the diversity between feeders;**

**(s) where Ergon Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a zone substation (or relevant substations for a sub-transmission line):**

For general information regarding the subtransmission planning process addressing all sections (s) (i to viii) refer to Regulatory Proposal attachment 07.02.04 Network Planning Process (at pages 60 to 77)

**(i) assumed future load transfers between related substations;**
**(ii) assumed underlying load growth rates (exclusive of *transfers* and specific *customer* developments);**
**(iii) assumed specific customer developments, and associated demand assumptions;**
**(iv) existing embedded generation capacity, and associated assumptions on the impact on demand levels;**

**(v) assumed future embedded generation capacity, and associated assumptions on the impact on demand levels;**

**(vi) existing non-network solutions, and the associated assumptions on the impact on demand levels;**

**(vii) assumed future non-network solutions, and associated assumptions on the impact on demand levels; and**

**(viii) diversity with related substations.**

**8.4 Provide:**

**(a) evidence that any independent verifier engaged by Ergon Energy has examined the reasonableness of the method, processes and assumptions in determining the forecasts and has sufficiently capable expertise in undertaking a verification of forecasts; and**

An independent verifier, ACIL Allen Consulting, was engaged by Ergon Energy to examine the reasonableness of the method, processes and assumptions in determining the forecasts.

Following the AER's concern over Ergon Energy's forecasting methods, Ergon Energy enhanced its forecasting approach using econometric methods and temperature corrected values. Ergon Energy uses a combination of top-down and bottom-up approaches to provide a robust methodology. Following implementation of the new forecasting process ACIL Allen performed an independent review of the process. The Regulatory Proposal attachment 07.02.09 Load Forecast System Maximum Demand Reference Document, details the outcome of this review. In the document ACIL Allen states, in relation to the new forecasting process, that:

- Ergon Energy has developed an independent system maximum demand methodology that can be used to reconcile spatial forecasts
- Ergon Energy has developed a methodology that allows for variation in key economic, demographic, appliance and weather factors
- Ergon Energy now applies a weather normalisation process to its forecasting process
- Ergon Energy has documented its processes and methodology where previously documentation was sparse.

As a result of this report and additional work done by Ergon Energy to address recommendations in the report, Ergon Energy believes its methodology is reasonable, as it was reviewed independently as being consistent with good demand forecasting practice.

Regulatory Proposal attachment 07.02.08 Energy Demand Forecast Method, gives a detailed explanation on the approach and methodology applied. Also refer to Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary [section 3.5 Demand Forecasting, page 12].

Discussion and details on Energy and Customer Number forecast can be found in Regulatory Proposal attachment 07.02.08 Energy Demand Forecast Method.

**(b) documentation, analysis and/or models that provide reasonable evidence of the results of each independent verification referred to in sub-paragraph (a) above.**

Evidence embedded in documentation (as above):

- Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary [section 3.5 Demand Forecasting, page 12]; and
- Regulatory Proposal attachment 07.02.08 Energy Demand Forecast Method.

# 9. CONNECTIONS EXPENDITURE REQUIREMENTS

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to connections expenditure are as follows:

- 0B.01.01 Appendix B: Capital expenditure forecasts for Standard Control Services
- 07.00.03 Customer Initiated Capital Works Expenditure Forecast Summary
- 07.00.09 Unit Cost Methodologies Summary
- 07.03.01 Model Doc Ergon Energy CICW Forecast Model
- 07.03.02 CICW Model Report
- 09.01.01 Ergon Energy Connection Policy.

## 9.1 Provide and describe the methodology and assumptions used to prepare the forecasts of connection works including:

The methodology and assumptions Ergon Energy has used to prepare the forecasts of connection works are provided in supporting document:

- Regulatory Proposal attachment 07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary [section 5, Appendix A]

**(a) Estimation of *connection* unit costs for each *customer type;* and**

The estimate of connection unit costs for each customer type is provided in the following documents:

- Regulatory Proposal attachment 07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary [section 6.4 Customer Initiated capital works]; and

- Regulatory Proposal attachment 07.00.09 Unit Cost Methodologies Summary [section 7.1.1 Customer Initiated capital works].

**(b) Connection volumes for each customer type.**

Volumes for each customer type are obtained from a correlation of historical quantities with econometric drivers.

Details are discussed in the following documents:

- Regulatory template 2.5 Connections, Basis of Preparation document;

- Regulatory Proposal attachment 07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary [section 5, Appendix B]; and

- Regulatory Proposal attachment 07.03.01 Model Documentation Ergon Energy CICW Forecast Model.

## 9.2 Ergon Energy must provide its estimation of customer contributions based upon the estimated life and revenue to be recovered from connection assets, including:

**(a) the expected life of the *connection*;**

Ergon Energy's approach to estimating customer contributions is provided in Regulatory Proposal attachment 07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary [section 3.6, Appendix A].

Individual capital contributions are calculated in accordance with the capital contributions policy as, and when, required during the regulatory control period. This policy has regard to all matters 9.2 (a – c).

Refer to Regulatory Proposal attachment 09.01.01 Ergon Energy Connection Policy.

**(b) the average consumption expected by the customer over the life of the connection; and**

Ergon Energy's approach to estimating customer contributions is provided in Regulatory Proposal attachment 07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary [section 3.6, Appendix A].

Individual capital contributions are calculated in accordance with the capital contributions policy as, and when, required during the regulatory control period. This policy has regard to all matters 9.2 (a – c).

Refer to Regulatory Proposal attachment 09.01.01 Ergon Energy Connection Policy.

**(c) any other factors that influence the expected recovery of the distribution network use of system charge to customers.**

Ergon Energy's approach to estimating customer contributions is provided Regulatory Proposal attachment 07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary [section 3.6, Appendix A].

Individual capital contributions are calculated in accordance with the Connection Policy, as and when required, during the regulatory control period.  This policy has regard to all matters 9.2 (a – c).

Refer to Regulatory Proposal attachment 09.01.01 Ergon Energy Connection Policy.

# 10. OPERATING AND MAINTENANCE EXPENDITURE

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to opex are as follows:

- 0A.01.01 How Ergon Energy Compares
- 0A.01.02 Best Possible Price
- 0A.01.04 Engagement Program
- 0A.02.01 Huegin - Ergon Benchmarking
- 0A.02.03 Huegin – Ergon Energy Category Analysis Benchmarks
- 0A.02.04 Huegin – 2012 Distribution Benchmark Summary
- 0B.01.01 Appendix A: Operating expenditure forecasts for Standard Control Services
- 06.01.01 Opex Forecast Summary
- 06.01.02 System Related Operating Expenditure Summary
- 06.01.03 Ergon Opex Productivity Analysis
- 06.01.04 Step Changes
- 06.01.05 Meeting the Rule Requirements
- 06.01.06 Certification of Reasonableness
- 06.02.51 Veg Mgmt Strategy.

## Total forecast operating and maintenance expenditure

**10.1 Provide:**

**(a) the model(s) and the methodology Ergon Energy used to develop its total forecast opex;**

Refer to Regulatory Proposal attachments 03.03 Detailed Regulatory Interface Models and Regulatory Proposal attachment 06.02.06 Base Step Trend database.

**(b) justification for Ergon Energy's total forecast opex, including:**

**i. why the total forecast opex is required for Ergon Energy to achieve each of the objectives in clause 6.5.6(a) of the NER;**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 3.1.

**ii. how Ergon Energy's total forecast opex reasonably reflects each of the criteria in clause 6.5.6(c) of the NER; and**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 3.2.

**iii. how Ergon Energy's total forecast opex accounts for the factors in clause 6.5.6(e) of the NER;**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 3.3.

**10.2 Provide:**

**(a) the quantum of non-recurrent costs for each year of the *forthcoming regulatory control period*; and**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary ts, section 2.5 for Non-recurrent expenditure within the Base Step Trend.

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, 2.9 and 2.10 for costs that are forecast outside of Base Step Trend.

**(b) an explanation of each non-recurrent cost;**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.5 for Non-recurrent expenditure within the Base Step Trend.

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, 2.9 and 2.10 for costs that are forecast outside of Base Step Trend.

**10.3 if Ergon Energy used a revealed expenditure *Base year* approach to develop its total forecast opex, provide:**

**(a) the *Base year* Ergon Energy used; and**

2012/13

**(b) explanation and justification for why that Base year represents efficient and recurrent costs;**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.2 and 2.4.

**10.4 If Ergon Energy did not use a revealed expenditure *Base year* approach to develop its total forecast opex, provide:**

**(a) its forecast expenditure by *Opex Category* for each year of the *forthcoming regulatory control period* in *regulatory template* 2.16.2 for *standard control services* opex;**

Not applicable.

**(b) in Microsoft Excel format, clear reconciliation (including all calculations and formulae) of Ergon Energy's total forecast opex to:**

**i. forecast *standard control services* opex by driver in *regulatory template* 2.16.1;**

**ii. forecast *standard control services* opex by *Opex Category* in *regulatory template* 2.16.2;**

Not applicable.

**(c) its explanation of major drivers for the increases and decreases in expenditure by Opex Category in the forthcoming regulatory control period compared to actual historical expenditure;**

Not applicable.

**(d) its explanation and justification for:**

**i. whether Ergon Energy considers there is a year of historic opex that represents efficient and recurrent costs; or**

**ii. why Ergon Energy considers no year of historic opex represents efficient and recurrent costs.**

Not applicable.

**Output growth**

**10.5 Provide the amount of total forecast opex attributable to output growth changes for each year of the *forthcoming regulatory control period* in *regulatory template* 2.16.1 for *standard control services* opex.**

We have responded to this requirement in regulatory template 2.16.1 for Standard Control Services (SCS) opex.

**10.6 Provide:**

**(a) the output growth drivers Ergon Energy used to develop the amount of total forecast opex attributable to output growth changes;**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.1.

**(b) any economies of scale factors applied to the growth drivers;**

Ergon Energy has calculated an implied economy of scale factor based on the productivity factor of -1%. We respond to the productivity growth in sections 10.1o and 10.11 of this document. The implied value for the economies of scale appears below; however Ergon Energy does not use this value as an adjustment to the output growth driver.

| Scale Factor | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| **scale on network** | 70.5% | 101.1% | 113.2% | 115.4% | 86.0% |
| **scale on customer** | 61.1% | 55.7% | 60.5% | 60.8% | 60.5% |

**(c) evidence that the growth drivers explain cost changes due to output growth; and**

Please refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.1 table 8.

**(d) if Ergon Energy applied any composite multiple output growth drivers:**

**i. the inputs for each composite multiple output growth driver; and**.

**ii. the weightings for each input;**

Network Growth is a composite growth driver and has been calculated as a simple average of the forecast annual growth in zone substation capacity, distribution line length and the number of distribution transformers over the forthcoming regulatory control period. Given Network Growth is calculated as a simple average, each component is weighted as one third of the total driver.

Please refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.1 table 7 for the year on year calculations.

**10.7 Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Ergon Energy:**

**(a) applied the output growth drivers; and**

Through the application of our Base Step Trend, we apply the growth drivers after the establishment of the efficient base year. Once all provisions, one-off adjustments to the base year, and the 15% reductions to overheads have been applied, we apply the growth driver (either Network Growth or Customer Growth) to the relevant expenditure category.

Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.1 discusses the methodology.

**(b) accounted for economies of scale.**

Ergon Energy does not explicitly adjust for economies of scale; however the implied adjustment is shown in 106(b) above. After we apply the growth factor, we then apply a productivity adjustment of -1%. After the -1% adjustment the net effect of the application of growth drivers is shown in the table below.

| Net Factor | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| **Network growth + Network Productivity** | 0.418% | -0.011% | -0.117% | -0.133% | 0.163% |
| **Customer growth + Customer Productivity** | 0.637% | 0.796% | 0.652% | 0.644% | 0.653% |

### Real price changes

**10.8 Provide the amount of total forecast opex attributable to changes in the price of labour and materials for each year of the *forthcoming regulatory control period* in *regulatory template* 2.16.1 for *standard control services* opex.**

We have responded to this requirement in the regulatory template 2.16.1 for SCS opex.

**10.9 Provide an explanation of:**

**(a) how, in developing the amount of total forecast opex attributable to changes in the price of labour and materials, Ergon Energy applied the real price measures in *regulatory template 2.14*; and**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.2.

**(b) whether Ergon Energy's labour price measure compensates for any form of labour productivity change.**

Refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.2.

### Productivity change

**10.10 Provide the amount of total forecast opex attributable to changes in productivity for each year of the *forthcoming regulatory control period* in *regulatory template* 2.16.1 for *standard control services* opex.**

We have responded to this requirement in the regulatory template 2.16.1 for SCS opex.

**10.11 Provide, in percentage year on year terms, the productivity measure that Ergon Energy used to develop the amount of total forecast opex attributable to changes in productivity;**

Please refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.3. Ergon Energy applies a -1% productivity adjustment, creating the net of productivity and growth factors (shown above in 10.7).

**10.12 Provide an explanation of:**

**(a) how, in developing the amount of total forecast opex attributable to changes in productivity, Ergon Energy applied the productivity measure in paragraph 10.11;**

Ergon Energy adjusts the growth factors calculated for Network Growth and Customer growth by -1%. This creates an overall adjustment that is applied as a price adjustment to the year on year expenditure after the establishment of the efficient base year.

| Net Factor | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| **Network growth + Network Productivity** | 0.418% | -0.011% | -0.117% | -0.133% | 0.163% |
| **Customer growth + Customer Productivity** | 0.637% | 0.796% | 0.652% | 0.644% | 0.653% |

**(b) whether Ergon Energy's forecast productivity changes capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice; and**

Ergon Energy has responded to the use of the -1% productivity adjustment in 0A.01.02 Best Possible Price, and Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.7.3.

**(c) whether Ergon Energy's productivity measure includes productivity change compensated for by the labour price measure used by Ergon Energy to forecast the change in the price of labour.**

No, the labour price adjustment is calculated as a real price increase separate to the productivity adjustments.

**Opex step changes**

**10.13 Provide the amount of total forecast opex attributable to opex step changes for each year of the forthcoming regulatory control period in regulatory template 2.16.1 for standard control services opex.**

We have responded to this requirement in the regulatory template 2.16.1 for standard control services opex.

**10.14 Provide an explanation of why Ergon Energy considers:**

**(a) the efficient costs of the *Step change* are not provided by other components of Ergon Energy's total forecast opex such as base opex, output growth changes, real price changes or productivity change;**

Please refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.6 Step Changes and Regulatory Proposal attachment 06.01.04 Step Changes.

**(b) the total forecast opex will not allow Ergon Energy to achieve the objectives in clause 6.5.6(a) of the NER unless the Step change is included; and**

Please refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.6 Step Changes and Regulatory Proposal attachment 06.01.04 Step Changes.

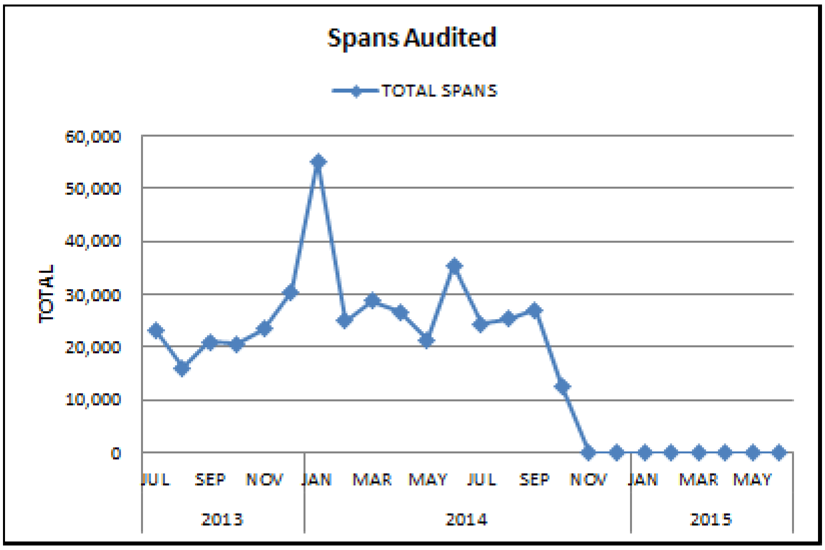
**(c) the total forecast opex will not reasonably reflect the criteria in clause 6.5.6(c) of the NER unless the Step change is included.**

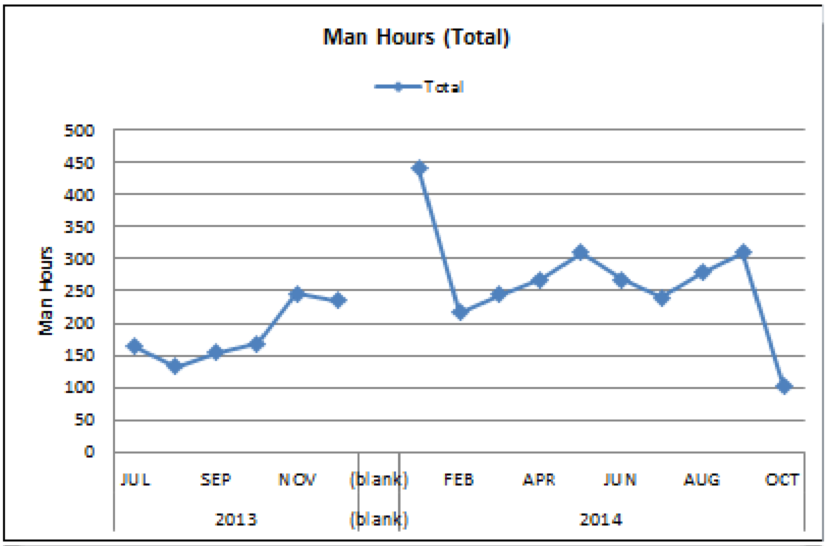
Please refer to Regulatory Proposal attachment 06.01.01 Opex Forecast Summary, section 2.6 Step Changes and Regulatory Proposal attachment 06.01.04 Step Changes.

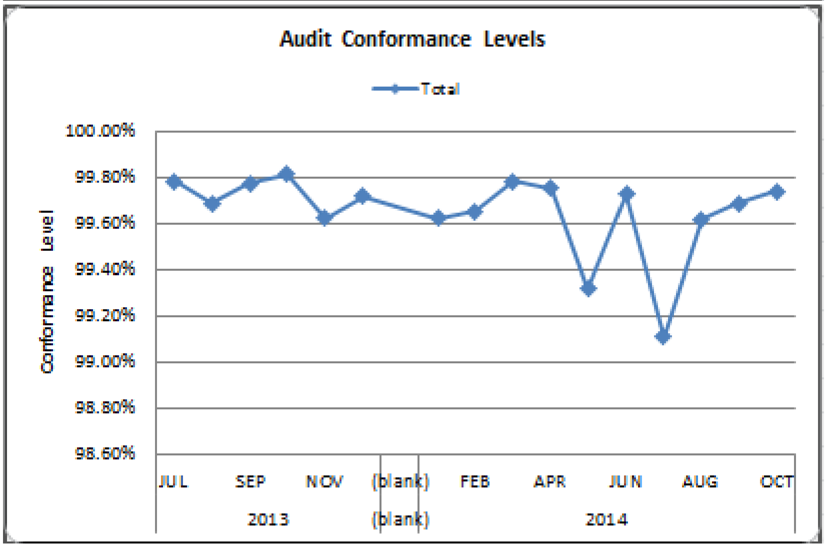
**Vegetation management**

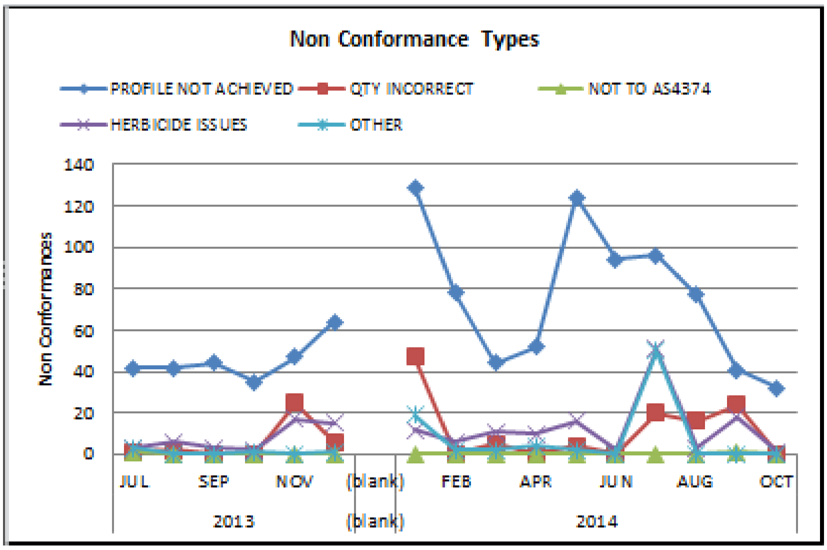
**10.15 Provide compliance audits of vegetation management work conducted by Ergon Energy during the current regulatory control period.**

The current system for undertaking compliance audits for vegetation management work has existed since 2013. Previous audits were conducted separately and the results were not collated. It is therefore not feasible to provide meaningful comparative results. The outcome of compliance audits since 2013 are depicted below:






Note: audits were not undertaken for the time periods labelled ‘blank’.

# 11. RISK MANAGEMENT AND INSURANCE

As identified in the Introduction section, there are a number of attachments to the Regulatory Proposal to which the AER should have regard when considering our Schedule 1 Response. The Regulatory Proposal attachments with general application to risk management and insurance are as follows:

- 04.02.01 AON – Ergon Insurance Premium Forecast
- 04.02.02 AON – Ergon Self Insurance Risk
- 06.02.03 Parametric Insurance.

### Risk Management Framework

**11.1 Provide information that sets out Ergon Energy's governance arrangements in relation to the management of risk, including:**

**(a) a risk appetite statement, which details the level of risk Ergon Energy's board is willing to accept including the nature and level of risks and the level of loss that can be sustained;**

To give effect to its commitment to risk management, Ergon Energy has developed a Risk Management Policy[4] to:

- Meet the expectations of employees, customers, the community, shareholders and other stakeholders that directors and management are able to demonstrate an understanding of the risks of the business and that they are being efficiently and effectively managed; and

- Provide explicit and proactive risk management systems and processes that contribute to achieving better financial and non-financial performance outcomes and with less volatility.

The primary objectives of Ergon Energy's risk management framework are:

- To ensure the strategic direction of the business is appropriate in light of the economic, social, political, legal and regulatory environment in which the business operates;

- Provide a means of identifying priorities (in terms of relative risk levels) and allocating scarce resources effectively and efficiently;

- Provide a means of demonstrating due diligence in discharging legal and regulatory obligations and meeting the expectations and standards of external stakeholders; and

- Provide a means of identifying, evaluating and maximising opportunities for business growth and diversification where such opportunities involve some level of risk.

In addition, Ergon Energy has developed a suite of policies in relation to areas of the business which, among other things, establish and set out the organisation's expectations for the management of risk applicable to those areas.

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[4] Ergon Energy EP 26 – Risk Management Policy

**(b) a risk management strategy that describes Ergon Energy's strategy for managing risk and the key elements of the risk management framework that give effect to this strategy; and**

Ergon Energy has implemented various strategies for achieving an effective and integrated risk management framework, some of which include the following:

- Common guidelines, terminologies and methods for the assessment and measurement of risk across all areas of the business having regard to specific operational needs and differences;
- Identified key areas of risk exposure and Ergon Energy's risk profile at the corporate level and reports on such matters on a regular basis to the Board;
- Ensuring that Risk Management related plans and strategies are integrated into the Business Planning Process and reflected in operational plans and processes;
- Defining acceptable levels or ranges of risk tolerance and risk appetite for different areas of the business and in relation to risks and opportunities;
- Ensuring that Disaster, Emergency and Business Continuity Planning is implemented to address disruption risks such as storms and cyclones, IT system breakdowns, critical supply network failures; and
- Ensuring that levels and areas of risk retention are appropriate and that where necessary, insurance or other forms of risk financing and risk transfer are in place.

### Risk Management Framework Methodology

#### *Standard for Corporate Risk Management*

Ergon Energy has developed a Standard for Corporate Risk Management (Risk Standard) based on AS/NZS ISO 31000 that forms part of Ergon Energy's risk management framework that:

- Sets out the principles and practices Ergon Energy shall follow to achieve effective risk management;
- Emphasises and provides guidance on how risk management shall be implemented and integrated into Ergon Energy through the development and continuous improvement of a risk management framework; and
- Describes a process for managing risk.

#### *Corporate Risk Management Guideline*

The Corporate Risk Management Guideline (Risk Guideline) supports the Risk Standard by providing practical guidance on how to implement the risk management process referred to in the Risk Standard. The Risk Guideline can be applied across Ergon Energy i.e. corporate level, business unit level, department level or for functions, projects, processes, activities, tasks, steps, products, services and assets.

The Risk Guideline can also be applied to any type of risk, whatever its nature, and whether having positive or negative consequences.

### *Corporate Risk Assessment Tables*

The Corporate Risk Assessment Tables (Risk Tables) provide criteria to perform risk assessments in Ergon Energy and are used in all cases unless another risk assessment methodology is prescribed. The Risk Tables are used in conjunction with the Risk Standard and Risk Guideline. A feature of the Risk Tables is the Risk Tolerability Table, shown below, which sets out the basis for the escalation of risk in the organisation based on the risk level assessed and from this the frequency and level of management action required.

<table>
<tr><th colspan="4">RISK TOLERABILITY CRITERIA, APPROVAL & ACTION REQUIREMENTS</th><th colspan="2"></th></tr>
<tr><th colspan="3">LEVEL of RISK</th><th>RISK APPROVAL POSITION</th><th colspan="2">ACTION REQUIREMENTS</th></tr>
<tr><td colspan="4">Extreme - Intolerable<br>(stop exposure immediately)</td><td colspan="2">Immediate action required, needs active management - introduce new or changed risk controls to reduce the RESIDUAL level of risk to the Tolerable Range.</td></tr>
<tr><td rowspan="6">Tolerable Range</td><td rowspan="2">High</td><td rowspan="6">ALARP<br>(Risk in this range managed to "as low as reasonably practicable")</td><td rowspan="2">Executive General Manager Approval (required to continue High RESIDUAL risk exposure)</td><td colspan="2">Needs active management - introduce new or changed risk controls based on Cost-Benefit Analysis and ALARP to reduce level of risk.</td></tr>
<tr><td>Monthly Report</td><td>High INHERENT Risks and above to be reported monthly to Risk & Assurance for inclusion in a Consolidated Business Unit / Corporate Risk Profile.</td></tr>
<tr><td rowspan="2">Medium</td><td rowspan="2">Group / General Manager Approval (required to continue Medium RESIDUAL risk exposure)</td><td colspan="2">Needs regular monitoring - monitor risks in conjunction with review of the effectiveness of the existing controls.<br>Introduce new or changed risk controls based on Cost-Benefit Analysis and ALARP.</td></tr>
<tr><td>Monthly Report</td><td>Medium INHERENT Risks and above to be reported monthly to Business Unit EGM for inclusion in Business Unit Risk Profile.</td></tr>
<tr><td rowspan="2">Low</td><td rowspan="2">Line Manager Approval (required to continue Low RESIDUAL risk exposure)</td><td colspan="2">Needs control review - monitor risks in conjuction with review of existing control procedures.</td></tr>
<tr><td colspan="2">Monthly risk review at workgroup level of all Low risks and above.</td></tr>
<tr><td></td><td>Very Low</td><td colspan="2">No Approval Required</td><td colspan="2">Periodic review of the risk and effectiveness of the existing controls.</td></tr>
</table>

### *Business Unit Risk Management Framework Documents*

In support of the Corporate Risk Management Framework Documents a suite of risk management related documents have been developed at the Business Unit level or functional which set standards and provide guidelines for the management of particular categories or areas of risk.

## Risk Management Framework Information

### *Corporate Risk Profile*

Ergon Energy maintains a Corporate Risk Profile (CRP) which includes risks identified by the Board and the Executive Leadership Team (ELT) that have the potential to significantly affect the achievement of the organisation's objectives. Risks included in the CRP are categorised as "Key" or "Other" with "Key" risks being those that have a residual rating of "High" or "Extreme" and "Other" risks being those that have a residual rating of

"Medium" or “Low”. The CRP is reviewed by the ELT monthly and Operational Risk Committee (ORC) quarterly. The CRP process requires that any changes to it be made only after the Board has agreed to them, following input from the ELT.

### *Business Unit Risk Registers*

Ergon Energy’s Business Units maintain risk registers which include risks which have the potential to significantly affect the achievement of business unit objectives and are reviewed and updated at quarterly and provided to the ELT and ORC.

### *Department and Project Risk Registers*

Departments within Business Units’ maintain risk registers which include risks which have the potential to significant affect the achievement of department objectives and are reviewed and updated periodically. Project risk registers are developed and maintained for various operating and capital projects initiated in Ergon Energy.

**(c) any other information that demonstrates Ergon Energy’s governance arrangements in relation to risks and their management.**

The effectiveness and efficiency of Ergon Energy’s risk management framework, is dependent upon having an appropriate governance structure in place with, among other things, includes well-defined roles and responsibilities.

The Board is ultimately responsible for Ergon Energy’s risk management framework. To that end, and to help it fulfil its responsibilities as they relate to risk management, the Board has established two subcommittees, namely the ORC and Audit and Financial Risk Committee (AFRC).

### *Operational Risk Committee*

The ORC assists the Board in fulfilling its corporate governance and oversight responsibilities by reviewing and reporting to the Board on business and operational risks (other than financial risks); and compliance with applicable requirements (other than financial compliance issues).

These include (without limitation), the following:

- Health and safety within the workplace and health and safety issues involving contractors or members of the public arising from Ergon Energy’s operations or works;
- The management of health and safety risks and exposures relating to employees and those relating to contractors and the public in connection with Ergon Energy’s assets or operations;
- Cultural heritage and environmental risks and exposures;
- General assets and electricity network asset risks;
- Risks relating to compliance with network security criteria;
- Planning, preparation, response and recovery from disruption events, including major asset failure, storms, cyclones, floods and tidal surges;

- Information and communications technology (ICT) risks; and
- Risk associated with implementation of key strategic projects or programmes, including the Strategic Enablement Programme (SEP); and legal and insurance claims management.

### *Audit and Financial Risk Committee*

The AFRC assists the Board in fulfilling its corporate governance and oversight responsibilities by reviewing and reporting to the Board on matters in order to provide ongoing assurance in the areas of:

- Financial integrity;
- Regulatory reporting;
- Financial risk and compliance issues;
- Internal controls; and
- Audit effectiveness and independence.

As part of the Board subcommittee reporting process, papers prepared by Management on particular risk management topics are provided to both the ORC and AFRC.

### *Chief Executive*

The Chief Executive’s key risk management responsibilities include:

- Setting the tone and promoting a risk management culture by providing clear and strong support for risk management;
- Overseeing the development and implementation of the risk management framework;
- Overseeing the review and update of the CRP and ensuring risks included into it are being managed appropriately and in line with risk appetite levels set by the Board;
- Reviewing key risk information, identifying key risk trends and assessing the impact on Ergon Energy as a whole and ensuring significant risks are managed in accordance with Board risk appetite levels;
- Monitoring the management of significant risks and the effectiveness of associated controls through the review and discussion of regular risk management reports; and
- Exercising due diligence to ensure compliance with health and safety obligations by taking reasonable steps that will support a health and safety culture, accountability, the allocation of resources and development of appropriate policies.

### *Executive Leadership Team*

The ELT is responsible for the oversight of the risk management framework, including the consideration and review of risk management policies and procedures. In addition, the ELT is responsible for establishing policies and reviewing the effectiveness of Ergon Energy’s approach to risk management including the status of significant risks.

The ELT's key risk management responsibilities include:

- Reviewing and updating the CRP and business unit risk profiles;
- Identifying new and emerging risks;
- Reviewing key risk information, identifying key risk trends and assessing the impact on each business unit;
- Monitoring the management of significant risks and the effectiveness of associated controls through the review and discussion of regular risk management reports for business units;
- Ensuring that adequate processes are being followed in relation to lower level risks;
- Setting the tone and promoting a risk management culture by providing clear and strong support for risk management; and
- Exercising due diligence to ensure compliance with health and safety obligations by taking reasonable steps that will support a health and safety culture, accountability, the allocation of resources and development of appropriate policies.

### *ELT Committees*

In support of the ELT, a number of management sub-committees have been established comprising ELT members and Senior Leadership Team members in relation to particular elements of Ergon Energy's corporate governance framework.

A key sub-committee is the Investment Review Committee (IRC), which is responsible for developing a balanced capital and operating fund investment portfolio and providing strategic oversight and scrutiny across that portfolio, including new business development and acquisitions. The key objectives of the IRC are to:

- Ensure an appropriate balance between asset, customer service, product and asset research and development and business change within the investment portfolio;
- Ensure the investment portfolio and the individual components of the portfolio adequately address risk management, purpose and performance outcomes, sustainability, efficacy and availability for business planning timeframes;
- Within the investment portfolio, review individual components beyond the investment thresholds of the managers reporting to the Chief Executive;
- Review variations outside the investment portfolio agreed funding and outcome expectations; and
- Provide strategic oversight and scrutiny to elements of the portfolio for continued alignment with the purpose, performance and delivery of projected outcomes.

Other key ELT subcommittees include the following:

- The Safety and Environment Advisory Team which oversees the development, implementation and maintenance of Ergon Energy's Health, Safety and Environment

Integrated Management System and ensuring appropriate management of health, safety and environment related incidents and issues.

- Executive Disaster Management Committee which oversees the prevention of, preparedness for, response to and recovery from disruption events that impact Ergon Energy. The main objectives of the Committee are to ensure Ergon Energy has in place appropriate plans, capabilities and resources to enable the organisation to efficiently and effectively plan for, respond to and recover from disruption events, and provide executive level direction and support in relation to disruption events and in doing so, safeguard the organisation's assets, and protect and preserve the safety of employees, contractors, customers and the community generally.

### *Risk and Assurance Function*

Ergon Energy has established a corporate Risk and Assurance function that oversees the development and implementation of the organisation's risk management framework.

Key responsibilities of the group include:

- Developing, enhancing and implementing risk management policies, procedures and systems;
- Co-ordinating and monitoring the implementation of risk management initiatives across the organisation;
- Working with risk owners to ensure that the risk management processes are implemented in accordance with agreed risk management policy and strategy;
- Reviewing business unit risk registers for consistency and completeness;
- Providing advice and tools to staff, management and the Board on risk management issues within the organisation, including facilitating workshops on risk identification and assessment;
- Promoting understanding of and support for risk management, including delivery of risk management training;
- Overseeing and updating organisational-wide risk profiles, with input from risk owners; and
- Ensuring relevant risk information (including new and emerging risks) is reported and escalated or cascaded, as the case may be, in a timely manner that supports organisational requirements.

### *Line Management and employees*

Risk owners are typically line managers, or functional specialists who assume responsibility for designing, implementing, and/or monitoring risk treatments. Risk owners are responsible for the following:

- Identifying new and emerging risks;
- Managing risks they have accountability for;

- Reviewing risks on a regular basis;
- Identifying and responding to control deficiencies that exist;
- Updating risk information pertaining to risks;
- Escalating risks where they are increasing in likelihood or consequence; and
- Providing information about the risk when it is requested.

All employees and contractors have a responsibility to apply the risk management process as part of their jobs. Their focus is on identifying risks and reporting these to the relevant risk owner and where possible and appropriate, they shall also manage these risks.

## Insurance

**11.2 General Instructions:**

**(a) Regulatory template 2.15.1 must provide a summary of all Ergon Energy's proposed insurance costs.**

Completed.

**(b) Regulatory template 2.15.2 and 2.15.3 seek more detailed information regarding total property and liability premiums only. The total property premiums forecast in regulatory template 2.15.2 must equal the sum of the premium forecasts classed as property insurance in regulatory template 2.15.1. The total liability forecast in regulatory template 2.15.3 must equal the sum of the premium forecasts classed as liability insurance in regulatory template 2.15.1.**

Completed.

**(c) Amounts are exclusive of GST.**

Completed.

**11.3 Provide the following information for each commercially insured risk listed in regulatory template 2.15.1:**

**(a) the name and description of each insured risk, including policy limits and sub-limits;**

### Property

#### Description

Section 1 - Material Damage, covers damage, loss, or destruction of selected real and personal property owned by Ergon Energy or which it is legally responsible, including damage caused by flood and cyclones.

Section 2 - Business Interruption, covers additional expenditure incurred for the purpose of avoiding or diminishing any reduction in revenue following the occurrence of an event that affects property integral to generating revenue.

In relation to the Material Damage section of the policy, categories of assets covered are: (1) general buildings and contents, (2) generation assets, (3) ICT assets, tools, office machines, and strategic spares.

### Limits

The limit of liability is [redacted] for Section 1 and 2 combined.

### Sub-limits

#### *Section 1*

- Theft of Property Insured other than Money or in Transit - [redacted]
- Money - Not Insured
- Unspecified damage - [redacted]
- Liability to Pay Tax - [redacted]
- Legal Liability to make enquiries - [redacted]
- Expediting Costs - [redacted]
- Reward - [redacted]
- Statutory Enquiries - [redacted]
- Emergency Services - [redacted]
- Personal Property (Directors, Employees, Visitors) - [redacted] per person
- Landscaping - [redacted]
- Clean-up and Exploratory Costs - [redacted]
- Extra Cost of Reinstatement - [redacted]
- Additional Extra Cost of Reinstatement - [redacted]
- Loss of Land Value - [redacted]
- Works of Art - [redacted]
- Property in the Open Air - [redacted]
- Theft of Property in the Open Air - [redacted]
- Glass - Replacement Value
- Boiler & Pressure Vessel Explosion - [redacted]
- Data/Computer/Media Breakdown - Not Insured
- Fusion - Not Insured
- Machinery Breakdown - Not Insured
- Property in Transit - Not Insured
- Spoilage of Stock and/or Merchandise - Not Insured.

#### *Section 2*

- Gross Profit / Revenue / Rentals - Not Insured
- Insured Payroll - Not Insured
- Severance Pay - Not Insured
- Claim Preparation Costs - [redacted]
- Additional Increased Cost of Working - [redacted]
- Fines and Penalties - [redacted]
- Contracted Purchases - Not Insured
- Accounts Receivable - Not Insured
- Public Utilities - [redacted]
- Property in the vicinity of the Premises - [redacted]
- Property in the Vicinity of Suppliers and Customers - [redacted]

- Property in Commercial Complex - [redacted]
- Special Attraction in the vicinity of the Premises - [redacted]
- General Area Damage - [redacted]
- Registered Vehicles on Premises - [redacted]
- Infectious Diseases limited to the aggregate - [redacted]
- Indemnity Period - 12 Months
- Uninsured Working Expenses - None
- Basis of Insuring Payroll - N/A.

## General Liability

### Description

The policy provides two sections of cover: Section 1 General and Products Liability and Section 2 Professional Indemnity.

Section 1 provides cover with respect to third party personal injury, property damage and financial loss claims in respect to Ergon Energy's business including, general operations, products, completed operations, bushfire, automobile, and electro-magnetic fields.

Section 2 provides cover with respect to liability for breach of professional duty in the provision of professional advice or services to third parties.

### Limits

#### *Section 1 – General liability*

- General liability - [redacted]
- Products liability - [redacted]
- Bushfire liability - [redacted]
- Automobile liability - [redacted]
- Non-Owned Aircraft Liability - [redacted]
- Electro Magnetic Fields liability - [redacted]

#### *Section 2 – Professional liability*

- Professional liability - [redacted]

### Sub-limits

Nil.

## Construction Works Material Damage

### Description

The policy provides cover for damage or loss of assets under construction for or on behalf of Ergon Energy.

### Limits

- Construction works - [redacted]
- Construction plant and equipment [redacted]

### Sub-limits

- Removal of Debris and Other Costs - [redacted]
- Expediting Expenses [redacted]
- Search and Locate Costs - [redacted]
- Professionals' Fees - [redacted]
- Mitigation Expenses - [redacted]
- Plant Hire Charges - [redacted]
- Claim Preparation Costs - [redacted]
- Government and other Fees - [redacted]
- Sue and Labour - Not Insured
- Inflation Protection - [redacted]
- Offsite Storage [redacted]
- Insured Property whilst in transit [redacted]

## Construction Works Liability

### Description

The policy provides cover for third party personal injury and property damage claims (including compensation and legal defence and other costs) associated in relation to the construction and refurbishment of substations undertaken by Tenix Australia Pty Ltd and UGL Engineering Pty Ltd on behalf of Ergon Energy.

### Limits

[redacted]

### Sub-limits

Nil.

## Directors' and Officers' Liability

### Description

The policy provides two types of cover:

- Section 1 provides directors, officers and employees acting in a managerial capacity with cover for financial loss in respect to claims made in relation to wrongful acts committed or allegedly committed where an indemnity has not been provided by Ergon Energy.
- Section 2 provides Ergon Energy with cover for claims for financial loss in respect to claims made in relation to wrongful acts committed or allegedly committed by directors, officers and employees acting in a managerial capacity where the organisation has provided an indemnity to them.

### Limits

[redacted]

### Sub-limits

Emergency Costs - [redacted]

Crisis containment - [redacted]

## Directors' and Officers' Liability Supplementary Legal Expenses

### Description

The policy provides three types of cover:

- Section 1 provides directors, officers and employees with cover for legal fees and other related expenses incurred in respect to (I) claims relating to wrongful acts committed or allegedly committed or (II) in relation to their attendance at any prosecution, inquiry, investigation, examination or other proceeding before a court or regulatory authority or tribunal at the direction of that court or regulatory authority or tribunal and where they have not been indemnified by Ergon Energy.
- Section 2 provides Ergon Energy with cover for legal fees and other related expenses incurred by directors, officers and employees where it is entitled or required to indemnify them.
- Section 3 provides Ergon Energy with cover for legal fees and other related expenses incurred in relation to its attendance at any prosecution, inquiry, investigation, examination or other proceeding before a court or regulatory authority or tribunal at the direction of that court or regulatory authority or tribunal.

### Limits

Aggregate limit - [redacted]

Per claim limit - [redacted]

### Sub-limits

Section 3 claims - [redacted]

## Environmental Liability

### Description

The policy provides two sections of cover.

- Section 1 provides pollution premises cover for third party bodily injury and property damage claims, remediation costs, and legal defence expenses arising out of new pollution (both of a sudden/accidental and gradual nature) in respect to the operation of isolated power stations, substations, power poles and related assets, and transportation of goods and third party asbestos exposure.
- Section 2 provides contractors pollution cover for: asbestos abatement; transportation, loading and unloading of fuel and oil; installation, testing and

commissioning, decommissioning and maintenance of power assets including but not limited to power transformers, power lines, and associated ancillary activities.

### Limits

[redacted] for Section 1 and Section 2.

### Sub-limits

Nil.

## Crime

### Description

The policy provides cover in respect to claims for financial loss relating to fraud committed by employees or third parties.  In particular, the following cover is provided:

- employee fraud (theft of money or other property);
- premises coverage (third party theft of money or other property from Ergon Energy premises);
- in transit coverage (third party theft of money or other property whilst being transported including that stored temporarily at the home of an employee);
- forgery coverage (third party forgery or alteration of cheques or other financial instruments, or payroll);
- computer fraud coverage (third party unlawful taking of money or other property by computer);
- funds transfer fraud coverage (third party unlawful electronic instructions issued to a financial institution to transfer money without the Insured’s consent);
- counterfeit currency fraud coverage (acceptance in good faith by the Insured of any postal or money order issued by a post office);
- credit card fraud coverage (third party forged, counterfeit, or altered charge in connection credit card issue by the Insured);
- identity fraud coverage (reimbursement of fees, costs and charges following the fraudulent adoption or alteration or theft of the identity of natural person);
- client coverage (loss sustained by a customer resulting from fraud or dishonesty committed by an employee);
- expense coverage (reimbursement of costs associated with investigations conducted to establish the existence, facts or amount of any loss or incurred in relation to identify fraud and computer violations); and
- crisis expense coverage (fees, costs, charges and expenses incurred for up to thirty days after discovery of a loss to retain the services of any public relations firm to

advise the Insured with respect to the management of any public communication concerning the Insured's business due to the public disclosure of the loss).

#### Limits

[redacted]

#### Sub-limits

Nil.

### Statutory Liability

#### Description

The policy provides Ergon Energy and directors, officers and employees with cover for legal costs and associated expenses and penalties payable to any regulatory authority pursuant to any claim that alleges a wrongful breach.

#### Limits

[redacted]

#### Sub-limits

Nil.

### Corporate Travel

#### Description

The policy provides Ergon Energy, directors and employees with cover in respect to claims for expenses incurred in respect to authorised business travel undertaken. In particular, the following cover is provided:

- personal injury (death, permanent total/partial disablement);
- medical expenses;
- emergency medical evacuation;
- repatriation of mortal remains;
- cancellation / curtailment / additional expenses;
- personal liability;
- luggage, personal effects, travel documents, money and credit cards, portable business equipment;
- alternative employee or resumption of assignment expenses;
- rental vehicle collision damage and theft excess cover;
- missed transport connection;
- extra territorial workers compensation;
- kidnap, ransom and extortion;
- political evacuation and natural disaster response; and
- corporate traveller's family assistance.

### Limits

[redacted] in the aggregate.

### Sub-limits

Non-Scheduled Aircraft [redacted]

Single Engine Aircraft [redacted]

Multi Engine Aircraft [redacted]

Helicopter [redacted]

Extra Territorial Workers Compensation [redacted]

Kidnap, Ransom & Extortion [redacted]

Political Evacuation & Natural Disaster Expenses [redacted]

## Marine Transit

### Description

The policy provides cover for damage or loss of assets while being transported internationally and domestically and also third party bodily injury and property damage arising in connection with the transport of assets.

### Limits

[redacted]

### Sub-limits

[redacted] – transformers.

Other sub-limits of liability include: airfreight charges [redacted]; containers owned by the Insured [redacted] per container); containers hired or leased by the Insured [redacted]; debris removal [redacted]; duration clause amendments ([redacted]); employees property in storage [redacted] any one employee); [redacted] in any one location); exhibition and display [redacted] any one loss any one location); expediting expenses [redacted]); fumigation expenses [redacted] of limit of liability whichever is greater); strikes diversion ([redacted] of limit of liability).

## Personal Accident Redundancy

### Description

The policy provides income support payments to employees who are made redundant and become employed with another organisation or self-employed and consequently suffer an injury resulting from an accident.

**Limits**

[redacted].

**Sub-limits**

Nil.

### Plantation Timber

**Description**

The policy provides cover for damage or loss of timber plantations owned by Ergon Energy for use as poles and cross-arms.

**Limits**

[redacted]

**Sub-limits**

[redacted]

[redacted]

**(b) a description of the general method used to forecast premiums (this may be in the form of an insurance premium forecast report by a qualified risk specialist); and**

Refer to Regulatory Proposal attachment 04.02.01 AON – Ergon Insurance Premium Forecast.

**(c) any changes in insurance cover between the current and forthcoming regulatory control periods.**

With effect from 30 September 2014, the following policies were discontinued

- Aviation Hull and Liability;
- Aviation Marine Transit; and
- Motor Vehicle.

Ergon Energy proposes to obtain parametric insurance in the 2015-20 regulatory control period to cover the loss or damage of electricity network assets subject to the AER approving the cost of it.

**11.4 Provide the following information regarding total property and total liability insurance reported in regulatory templates 2.15.2 and 2.15.3 respectively:**

**(a) a description of the systematic drivers of insurance premiums;**

Refer to Regulatory Proposal attachment 04.02.01 AON – Ergon Insurance Premium Forecast.

**(b) a description of the circumstances that have led to any premium changes over the current regulatory control period;**

The change in annual premiums has been is predominately driven by insurance market conditions rather than material changes in scope of coverage, limits of liability and deductibles.

**(c) a description of the method used to forecast premiums for the forthcoming regulatory control period, including estimated exposure growth and premium rate changes and any other adjustments made. Provide supporting evidence for exposure, premium rate changes, or any other proposed adjustments; and**

Refer to Regulatory Proposal attachment 04.02.01 AON – Ergon Insurance Premium Forecast.

**(d) an explanation of how the value of insured assets is derived for property insurance (e.g. replacement costs, insured value etc.).**

Refer to Regulatory Proposal attachment 04.02.01 AON – Ergon Insurance Premium Forecast.

**11.5 Where insurance is shared with other entities, provide:**

**(a) an explanation of the cost allocation approach used for each risk class;**

Ergon Energy arranges and obtains insurance for ICT provider SPARQ Solutions Pty Ltd (SS) as required under the Shareholders Deed between Ergon Energy, Energex and SPARQ Solutions. Ergon Energy owns 50% of the share capital of SS.

Legal entities within the Ergon Energy Group (EEG) for which insurance applies are Ergon Energy Corporation Limited (EECL), Ergon Energy Queensland Pty Ltd (EEQ) and Ergon Energy Technology Pty Ltd (EET). Business activities performed by Ergon Energy Corporation Limited are generally divided into regulated and unregulated categories and in respect to the latter include the ownership, construction, operation and maintenance of the isolated generation and distribution assets.

The cost of Ergon Energy's Insurance Programme is allocated to the above mentioned entities pursuant to the organisation's Regulatory Cost Allocation Methodology.

The percentages used to allocate the cost of Ergon Energy's Insurance Programme across the entities reflect a number of drivers, including labour division of effort, assets values and risk levels inherent in business activities performed.

The percentages used to allocate the cost of Ergon Energy's Insurance Programme for each risk class are the same i.e. they are not different.

**(b) an explanation of the cost allocation approach used for each risk class;**

| | |
|---|---|
| EECL (Regulated) | 79% |
| EECL (Unregulated) | 8% |
| Other (SS, EEQ, EET) | 13% |

**(c) the cost allocation (percentage) that underlies forecast premiums for the forthcoming regulatory control period. If the proportion allocated to Ergon Energy has changed, explain why.**

| | |
|---|---|
| EECL (Regulated) | 78% |
| EECL (Unregulated) | 9% |
| Other (SS, EEQ, EET) | 13% |

The proportion allocated to EECL Regulated has reduced by 1% and is generally attributable to an increase in the level of risk associated with particular unregulated activities performed in EECL.

**11.6 Provide a report from an appropriately qualified risk specialist verifying that Ergon Energy's forecast insurance premiums are efficient.**

Refer to Regulatory Proposal attachment 04.02.01 AON – Ergon Insurance Premium Forecast.

## Self-Insurance

**11.7 For each risk for which Ergon Energy is proposing a self-insurance allowance in the regulatory proposal**

**(a) provide a description of the risk and risk exposure including cover, exclusions and limit;**

Ergon Energy is proposing a self-insurance allowance in respect to public liability claims having a cost below the maintenance and aggregate deductible on the products and public liability insurance policy. Refer to Regulatory Proposal attachment 04.02.02 AON – Ergon Self Insurance Risk.

**(b) explain how provide a description of the risk and risk exposure including cover, exclusions and limit;**

Refer to Regulatory Proposal attachment 04.02.02 AON – Ergon Self Insurance Risk.

**(c) provide a record of historic losses and claims against the self-insurance fund as far as records allow;**

Refer to Regulatory Proposal attachment 04.02.02 AON – Ergon Self Insurance Risk.

**(d) explain why compensation should be provided for the risk. Where insurance is available from a commercial insurer and an insurance quote has been obtained, provide evidence that it is more efficient to self-insure for that risk;**

Refer to Regulatory Proposal attachment 04.02.02 AON – Ergon Self Insurance Risk.

**(e) confirm that the risk for which self-insurance is being sought is not recovered through any other mechanism; and**

Not aware of the self-insurance allowance being recovered through any other mechanism.

**(f) explain why, if a self-insurance allowance has not been sought for a particular risk in the 2010–11 to 2014–15 regulatory control period, it is being sought in the 2015–16 to 2019–20 regulatory control period.**

Not applicable.

**11.8 If Ergon Energy is proposing self-insurance for asset failure risk in the revenue proposal:**

Ergon Energy is not proposing any self-insurance for asset failure risk in the Regulatory Proposal.

**(a) Provide:**

**(i) the annual number of failures for each asset category for which self-insurance is being sought**

**(ii) the historical costs for each asset failure**

**(iii) a description of what those costs relate to, including any split between capex and opex.**

Not applicable.

**(b) Explain:**

**(i) where the self-insurance allowance is not based on the actual historical asset failure rates and costs, how the allowance has been forecast and why it is efficient**

**(ii) how the proposed capex has been taken into account in calculating the probability of asset failure for each asset category for which self-insurance is being sought.**

Not applicable.

**11.9 Provide a report from an appropriately qualified actuary or risk specialist verifying the calculation of risk and corresponding self-insurance premiums.**

Refer to Regulatory Proposal attachment 04.02.01 AON – Ergon Insurance Premium Forecast.

# 12. ALTERNATIVE CONTROL SERVICES

**12.1 The *overheads* relating to each *alternative control service* must be disclosed in accordance with paragraph 12.2.**

This information is provided in the Category Analysis RIN 2008-09 to 2013-14 and Reset RIN 2014-15 to 2019-20 in regulatory templates 2.10.1 and 2.10.2 Network & Business Overheads/ Total Overhead Expenditure – Alternative Control Services.

Please also refer to Regulatory Proposal attachment 05.06.02 Fixed fee services model and Regulatory Proposal attachment 05.06.03 Quoted Prices Services model.

**12.2 Provide a list of all of the individual services that Ergon Energy intends to provide to customers and levy charges for in the forthcoming regulatory control period that fit within the broader definitions of distribution services that the AER proposed to classify as alternative control services in the Framework and Approach Paper.**

All individual services are listed within the Regulatory Proposal attachment 02.01.01 Classification Proposal.

**12.3 Provide a definition of each alternative control service listed in paragraphs 13, 14 and 15, where Ergon Energy proposes a classification different to that in the Framework and Approach Paper.**

Ergon Energy does not propose to classify any services differently to the classifications contained in the AER's Framework and Approach paper.

**12.4 For each alternative control service listed in paragraphs 13, 14 and 15, specify the charges applicable during each year of the current regulatory control period. Also include proposed charges for each year of the forthcoming regulatory control period.**

Information for the current regulatory control period 2010-11 to 2014-15 charges for paragraph 13, 14 and 15 are provided in the Regulatory Proposal attachment 05.06.02 Fixed fee services model and Regulatory Proposal attachment 05.06.03 Quoted Prices Services model and Schedule 1 attachment 0C.04.02 ACS Workbook, worksheet 12.4.

Information for the forecast regulatory charges for 2015-16 to 2019-20 for fixed fee and quoted price services are provided in Regulatory Proposal attachment 05.05.01 Inputs and Assumptions for Alternative Control Services. Information for the forecast regulatory charges for 2015-16 to 2019-20 for Metering is provided in Regulatory Proposal attachment 05.03.01 Default Metering Services Summary. Information for the forecast regulatory charges for 2015-16 to 2019-20 for Public Lighting is provided in Regulatory Proposal attachment 05.01.01 Public Lighting Services Summary.

**12.5 For each alternative control service listed in paragraphs 13, 14 and 15, specify the total revenue earned by Ergon Energy in each year of the current regulatory control period and forthcoming regulatory control period.**

Information for the current and forecast regulatory control period revenue earned is provided in the Category Analysis RIN 2008-09 to 2013-14 and Reset RIN 2014-15 to 2019-20 in regulatory template 3.1 Revenue Alternative Control Services.

**12.6 For metering and public lighting alternative control services, specify the number of customers in each year of the *current regulatory control period*, and forecasts for the *forthcoming regulatory control period*.**

Information for current and forecast regulatory period customer numbers is provided in the Category Analysis RIN 2008-09 to 2013-14 in Template 4.3 Fee Based Services and 4.4 Quoted Services. Forecast customer numbers can be found in Schedule 1 Response attachment 0C.04.02 ACS Workbook, worksheet 12.6.

**12.7 For each *alternative control service* listed in paragraphs 12, 13 and 14, provide the labour rate(s) used to calculate the charges for the *current* and *forthcoming regulatory control periods***

Information for the current regulatory control period 2010-11 to 2014-15 labour rates has been included in Schedule 1 Response attachment 0C.04.02 ACS Workbook, worksheet 12.7 Labour Rates.

Information for the forecast regulatory control period labour rates for 2015-16 to 2019-20 will be provided in the Regulatory Proposal attachment ACS Pricing Inputs spreadsheet.

**(a) Specify the *labour classification level* used to provide the services e.g. outsourced or internally provided and labourer type.**

Quoted price and fixed fee services are provided in the following models – Regulatory Proposal attachment 05.06.02 Fixed fee services model and Regulatory Proposal attachment 05.06.03 Quoted Prices Services model.

Metering services utilises both internal and external staff (contractors) for completion of services. Internal staff will include Technical Service Person, Admin Employee, Para Professional, Professional Managerial and Apprentice.

Public Lighting services utilises both internal and external staff (contractors) for completion of work. Internal staff will include Power Worker, Technical Service Person, Admin Employee, Para Professional, Professional Managerial and Apprentice.

**(b) List all *direct costs*, and their quantum, in the make-up of the labour rate(s)**

Information for the current regulatory period 2010-11 to 2014-15 labour rates have been included in Schedule 1 attachment 0C.04.02 ACS Workbook ,worksheet 12.7 Labour Rates.

Information for the forecast labour rates for 2015-16 to 2019-20 will be provided in the following models – Regulatory Proposal attachment 05.06.02 Fixed fee services model and Regulatory Proposal attachment 05.06.03 Quoted Prices Services model.

**12.8 List each material category (e.g. meters, poles, brackets) required for the provision of *alternative control services* listed in the response to paragraphs 12, 13 and 14.**

**(a) Provide a description of each material category**

Metering Services are as below:

- Type 6 meters - Manually read accumulation meter which measures and records electrical energy in periods in excess of a trading interval.

Public Lighting Services are as below:

- Luminaire – apparatus which distributes, filters or transforms the light transmitted from one or more lamps and which includes, except for the lights themselves, all the parts necessary for fixing and protecting the lamps and, where necessary, circuit auxiliaries together with the means for connecting them to the electrical supply
- Lamp –the light source of the luminaire
- Brackets – outreach arms or mounting frames used to attach luminaires
- Poles (streetlight specific) – a vertical structure designed exclusively to support luminaires either directly or by use of brackets.

Fee Based and Quoted Services are as below:

- In the AER's Framework and Approach paper (at page 68), the AER acknowledged that there are many types of materials used in the provision of Alternative Control Services. Since the materials used in the provision of quoted price services will reflect the actual requirements of the job, we are unable to specify the material categories for each service
- Ergon Energy has attached our current inventory catalogue. Materials used in the provision of quoted price services will be sourced from this catalogue (as updated from time-to-time)
- Materials are not used in the provision of fixed fee services.

**(b) Provide the average unit costs for each material category**

Information for the average unit costs for Metering and Public Lighting services have been included in Schedule 1 Response attachment 0C.04.02 ACS Workbook, worksheet 12.8.

Information for Fee based and Quoted Services have been excluded on the basis listed above in worksheet 12.8.

**(c) List all direct costs included in the unit costs**

Information for the average unit costs for Metering and Public Lighting services have been included in Schedule 1 Response attachment 0C.04.02 ACS Workbook, worksheet 12.8.

Information for Fee based and Quoted Services have been excluded on the basis listed above in worksheet 12.8 a.

**(d) Specify the calculation of the quantum of direct materials costs included in the unit cost of materials.**

Type 6 meter direct material costs were calculated by a bottom-up build of components and validated by previous meter replacement programs.

Streetlight direct material costs were calculated by applying the historical average of direct cost from 2013-14 against the average unit cost.

Information for Fee based and Quoted Services have been excluded on the basis listed above in worksheet 12.8 a.

# 13. FEE BASED AND QUOTED ALTERNATIVE CONTROL SERVICES

**13.1 Provide a description of each *fee based* and *quoted* service, explaining the purpose of the service and list the activities which comprise each service. The list of *fee based* and *quoted services* should be consistent with those services listed in Ergon Energy's annual tariff proposals.**

Please refer to Appendix A – Alternative Control Services internal service descriptions of Regulatory Proposal attachment 02.01.01 Classification Proposal. Our annual Pricing Proposals will reflect these services.

**(a) Specify if the charges are for *fee based* and/or *quoted* alternative control services;**

Please refer to Appendix B – Ergon Energy services by pricing mechanism of Regulatory Proposal attachment 02.01.01 Classification Proposal (specifically, section 2).

**(b) Explain the reasons for the different charge with reference to the costs incurred;**

Chapters 4 and 5 of Regulatory Proposal attachment 05.05.01 Inputs and Assumptions for ACS explain the reasons for different charge with reference to the costs incurred.

**(c) Explain the method used to set the different charge; and**

This is addressed in Regulatory Proposal attachment 05.05.01 Inputs and Assumptions for ACS.

**(d) Provide the calculations underpinning the different charge.**

The calculations underpinning each charge are provided in the following spreadsheets:

- Regulatory Proposal attachment 05.06.02 Fixed fee services model – "Calculation" worksheet
- Regulatory Proposal attachment 05.06.03 Quoted Price Services model – "Calculation" worksheet.

Note: the charges for quoted price services are based on worked examples and are indicative only. The actual charges for these services will be determined at the time of the customer's enquiry and will reflect the actual requirements of the service provided.

**13.2 Identify the tasks involved in providing the service in regulatory templates 4.3 and 4.4**

**(a) Map the class of labour required to provide the service listed in regulatory templates 4.3 and 4.4.**

The class/classes of labour required to provide each service is provided in the following spreadsheets:

- Regulatory Proposal attachment 05.06.02 Fixed fee services model – “Assumptions” worksheet
- Regulatory Proposal attachment 05.06.03 Quoted Price Services model – “Assumptions” worksheet.

Note: the classes of labour required to provide quoted price services are based on worked examples and are indicative only. The actual classes of labour will reflect the actual requirements of the service provided.

**(b) The number of workers required to undertake the task and deliver the service**

The number of workers required to deliver the service is provided in the following spreadsheets:

- Regulatory Proposal attachment 05.06.02 Fixed fee services model – “Assumptions” worksheet
- Regulatory Proposal attachment 05.06.03 Quoted Price Services model – “Assumptions” worksheet.

Note: the number of workers required to provide quoted price services are based on worked examples and are indicative only. The actual number of workers will reflect the actual requirements of the service provided.

**(c) The average time required to complete the task and deliver the service**

The average time required to deliver the service is provided in the following spreadsheets:

- Regulatory Proposal attachment 05.06.02 Fixed fee services model – “Assumptions” worksheet
- Regulatory Proposal attachment 05.06.03 Quoted Price Services model – “Assumptions” worksheet.

Note: the average time required to deliver quoted price services are based on worked examples and are indicative only. The actual time will reflect the actual requirements of the service provided.

**13.3 If materials are required to provide the service, specify each material category**

In its Framework and Approach Paper (p68), the AER acknowledged that there are many types of materials used in the provision of Alternative Control Services. Since the materials used in the provision of quoted price services will reflect the actual requirements of the job, we are unable to specify the material categories for each service.

Ergon Energy has attached our current inventory catalogue. Materials used in the provision of quoted price services will be sourced from this catalogue (as updated from time-to-time).

Materials are not used in the provision of fixed fee services.

**13.4 Provide all current and proposed charges for each** fee based **and** quoted **alternative control service in the current and forthcoming regulatory control periods.**

Current and proposed charges for these services are provided in the following spreadsheets:

- Regulatory Proposal attachment 05.06.02 Fixed fee services model – Price summary worksheet
- Regulatory Proposal attachment 05.06.03 Quoted Price Services model – Price summary worksheet.

Where there is no equivalent Alternative Control Service in the current regulatory control period, we have inserted “N/A” in the respective years.

# 14. METERING ALTERNATIVE CONTROL SERVICES

**14.1 For meter types 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the:**

**(a) Direct materials and direct labour costs;**

Information for the current and forecast regulatory period 2010-11 to 2019-20 direct materials and labour costs have been included in Schedule 1 Response attachment 0C.04.03 ACS Workbook, worksheet 14.1a e.

**(b) Installation costs;**

Information for the current regulatory period 2010-11 to 2014-15 installation costs have been included in Schedule 1 Response attachment 0C.04.03 ACS Workbook, worksheet 14.1 b c

Information for the forecast period 2015-16 to 2019-20 is supplied in the Regulatory template 4.2, Table 4.2.2 Cost Metrics – New Meter Installation.

**(c) Meter purchase costs;**

Information for the current regulatory period 2010-11 to 2014-15 meter purchase costs have been included in Schedule 1 Response attachment 0C.04.03 ACS Workbook, worksheet 14.1 b c.

Information for the forecast period 2015-16 to 2019-20 period meter purchase costs are supplied in the Regulatory Reset RIN in Table 4.2.2 Cost Metrics – Meter Purchases.

**(d) Volumes of work;**

Information for current and forecast regulatory period 2010-11 to 2014-15 volumes of work is provided in the Category Analysis RIN 2008-09 to 2013-14 and Regulatory Reset RIN 2014-15 to 2019-20 in regulatory template 4.4 Quoted Services. Information for Metering Services is included in the following Service Subcategories:

- Move the Meter
- Meter Exchange at Retailer Request
- Removal of a Meter
- Removal of a Load Control Device
- Provision, installation and Maintenance of Meters beyond Minimum Requirements
- Prepayment Meters at Customer Request
- Meter Test Whole Current
- Meter Test (CT/VT)
- Reprogram Card Meters
- Special Meter Read
- Meter Check Read
- Meter Data Service Above Min Requirements
- Default Metering ACS Charge.

**(e) Other costs associated with providing metering services;**

Information for the current regulatory period 2010/11-2014/15 other costs have been included in Schedule 1 attachment 0C.04.03 ACS Workbook, worksheet 14.1 a e.

Information for the forecast regulatory period 2015/16-2019/20 other costs are supplied in Regulatory Reset RIN Table 4.2.2 Cost Metrics – Other Metering Type 6.

**(f) Type of meters installed and forecast to be installed, separately for new meters and for replacement meters;**

Information for the current and forecast regulatory period 2010-11 to 2019-20 meter installation details have been included in Schedule 1 Response attachment 0C.04.03 ACS Workbook, worksheet 14.1 f.

**(g) The volume of meters by type set out in (f) and the revenue earned and forecast to be earned by each meter type; and**

Information for the current and forecast regulatory period 2010-11 to 2019-20 revenue are supplied in Regulatory Reset RIN Table 3.1 Revenue Alternative Control Services – Revenue from Metering Charges

**(h) The total operating and** maintenance **costs incurred, and forecast to be incurred, for metering services.**

Information for the current and forecast regulatory period 2010-11 to 2019-20 operating and maintenance costs is supplied in Regulatory Reset RIN Table 2.1.4 – Alternative Services Opex.

**14.2 For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of:**

**(a) The type of work undertaken (e.g. meter reconfiguration, special meter read) including a description of the activities undertaken to provide the service;**

Information for metering Alternative Control Services work to be undertaken is provided within Regulatory Proposal attachment 02.01.01 Classification Proposal.

**(b) The labour costs involved in providing the service, including any overheads;**

Information for the current regulatory period 2010-11 to 2014-15 Labour Costs have been included in Schedule 1 attachment 0C.04.03 ACS Workbook, worksheet 14.2 b c.

Information for the forecast regulatory period 2015-16 to 2019-20 Labour Costs are provided in Regulatory Proposal attachment 05.06.03 Quoted Prices Services model.

**(c) Any materials costs involved in providing the service;**

Information for the current regulatory period 2010-11 to 2014-15 Materials Costs have been included in Schedule 1 Response attachment 0C.04.03 ACS Workbook, worksheet 14.2 b c.

Information for the forecast regulatory period 2015-16 to 2019-20 Labour Costs are provided in Regulatory Proposal attachment 05.06.03 Quoted Prices Services model.

**(d) The number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;**

Information for the current and forecast regulatory period 2010-11 to 2019-20 volume of services is supplied in Regulatory Reset RIN regulatory template 4.4 Quoted Services Volumes. Assumptions are included in the Basis of Preparation for regulatory template 4.4.

**(e) The charge per service; and**

Information for the current and forecast regulatory period 2010-11 to 2019-20 charge per service is included in Schedule 1, section 12. Alternative Control Services, specifically section 12.4.

**(f) The revenue earned by each service.**

Information for the current regulatory period 2010-11 to 2014-15 revenue earned per service is included in Schedule 1 Response attachment 0C.04.03 ACS Workbook, worksheet 14.2 f.

Information for the forecast regulatory period 2015-16 to 2019-20 revenue earned per service is unavailable. A total Metering Service level is available in Regulatory Reset RIN Table 3.1 Revenue Alternative Control Services – Revenue from Metering Charges.

# 15. PUBLIC LIGHTING ALTERNATIVE CONTROL SERVICES

**15.1 Specify which items are capital expenditure and operational expenditure for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period.**

Capital Expenditure is considered for the service of Light Installation and materials for Light Replacement.

Operational Expenditure is considered for the service of Light Maintenance and all other costs except materials for Light Replacement.

**15.2 Provide unit costs for the current regulatory control period and forecast for the forthcoming regulatory control period for:**

**(a) Luminaires;**

This information has been provided for current and forecast regulatory period 2010-11 to 2019-20 in Schedule 1 Response attachment 0C.04.04 ACS Workbook, worksheet 15.2.

**(b) Dedicated street lighting poles;**

This information has been provided for current and forecast regulatory period 2010-11 to 2019-20 in Schedule 1 Response attachment 0C.04.04 ACS Workbook, worksheet 15.2.

**(c) Brackets;**

This information has been provided for current and forecast regulatory period 2010-11 to 2019-20 in Schedule 1 Response attachment 0C.04.04 ACS Workbook, worksheet 15.2.

**(d) Lamps;**

This information has been provided for current and forecast regulatory period 2010-11 to 2019-20 in Schedule 1 Response attachment 0C.04.04 ACS Workbook, worksheet 15.2.

**(e) Photoelectric cells;**

This information has been provided for current and forecast regulatory period 2010-11 to 2019-20 in Schedule 1 Response attachment 0C.04.04 ACS Workbook, worksheet 15.2.

**(f) Labour rate (per hour);**

This information has been provided for current and forecast regulatory period 2010-11 to 2019-20 in Schedule 1 Response attachment 0C.04.04 ACS Workbook, worksheet 12.7 Labour Rates in the Power Worker Classification.

**(g) Miscellaneous materials.**

This information is not collected by Ergon Energy, due to the volume of miscellaneous materials used.

**15.3 Provide the depreciation period in years for each type of luminaire.**

Both Major and minor luminaires are depreciated over a 20 year period.

**15.4 Provide the bulk change cycle in years for lamps and photoelectric cells.**

The bulk lamp replacement program works in a 3 year cycle. Photoelectric cells are replaced in a 6 year cycle.

**15.5 Provide details of the average replacement age of each type of luminaire.**

This information has been provided in the Category Analysis RIN for 2013-14 in Table 5.2.1 – Public Lighting.

**15.6 Provide the number of luminaires, by type.**

This information has been provided in the Category Analysis RIN for 2013-14 in Table 4.1.1 – Descriptor Metrics.

**15.7 Provide the number of luminaires, poles and brackets replaced per year, for the current and forthcoming regulatory control periods.**

This information has been provided in the Category Analysis RIN for 2013-14 in Table 2.2.1 – Replacement Expenditure, volumes and asset failures by asset category.

**15.8 Provide details, including assumptions used, for any other costs that are incurred for the provision of public lighting services.**

Other costs incurred for the provision of public lighting services are included in Business Overheads. This includes such activities as:

- Customer Engagement
- Data Management Services
- Audit Programs
- Safety and Design Compliance
- General Business Functions.

This information is provided in the Category Analysis RIN 2008-09 to 2013-14 and Reset RIN 2014-15 t 2019-20 in Template 2.10.1 and 2.10.2 Network & Business Overheads / Total Overhead Expenditure – Alternative Control Services.

**15.9 Provide models and/or modelling that underpins proposed charges for the forthcoming regulatory control period and the reasons for the assumptions behind those forecasts.**

This information is provided in Regulatory Proposal attachment 05.02.03 PLPTRM Data Model with Prices.

The assumptions that underpin Ergon Energy's charges for the forthcoming regulatory control period is provided in Regulatory Proposal attachment 05.01.01 Forecast Expenditure Summary Public Lighting Services 2015 to 2020, Section 8 Proposed Street Lighting ACS prices.

# 16. ECONOMIC BENCHMARKING

**16.1 Complete the Economic Benchmarking *regulatory templates* (3.1 to 3.7) in accordance with:**

**(a) The instructions and definitions for variables within: Economic benchmarking RIN For distribution network service providers Instructions and Definitions Ergon Energy (ABN 50 087 646 062) November 2013; and**

**(b) the instructions in paragraphs 16.1 to 16.10; however,**

**(c) If there is inconsistency between the instructions in paragraphs 16.1 to 16.10 and those in the instructions and definitions for variables within: Economic benchmarking RIN for distribution network service providers Instructions and Definitions Ergon Energy (ABN 50 087 646 062) November 2013 the instructions in paragraphs 16.2 to 16.9 take precedence.**

Ergon Energy confirms that the responses in regulatory templates 3.1-3.7 are provided in accordance with the above instructions.

**16.2 The forecast revenue groupings in regulatory templates 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous regulatory years, subject to the following provisions:**

**(a) Total revenues must equal the total forecast revenues proposed by Ergon Energy in its revenue proposal, and**

**(b) Revenue groupings must reflect Ergon Energy's forecast demand for its services in the Forthcoming Regulatory Control Period in its revenue proposal.**

Ergon Energy confirms that the revenue and revenue groupings in regulatory templates 3.1.1 and 3.1.2 reflect the forecast revenues and revenue groupings in the regulatory proposal except in the case of Alternative Control Services. The AER has previously provided advice in respect of the Reset RIN regulatory templates 4.3 and 4.4, which indicated that forecast volumes were not expected for fixed fee and quoted services, on the understanding that opex forecasts had been determined via a base step trend model. As no volumes were used to calculate costs, no volumes were therefore used to calculate revenues.

Please note, the values presented in regulatory templates 3.1.1 and 3.1.2 are presented in nominal dollars, so as to reflect the numbers in the regulatory template. This is despite the requirement of the template for real dollars.

**16.3 Information provided in regulatory templates 3.2.1 and 3.2.2 must reflect Ergon Energy's *Cost Allocation Method* to take effect on 1 July 2015.**

Ergon Energy confirms that the information in regulatory templates 3.2.1 and 3.2.2 reflects Ergon Energy's Cost Allocation Method taking effect on 1 July 2015.

**16.4 The definition of a tree must be applied when completing the variables "Average number of trees per urban and CBD vegetation maintenance span" (DOEF0208) and "Average number of trees per rural vegetation maintenance span" (DOEF0209)**

Ergon Energy confirms that the definition of a tree (pursuant to the Regulatory Information Notice issued 29 August 2014) has been applied when completing the above listed variables.

**16.5 In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Ergon Energy is not responsible for the vegetation management associated with the span are not to be counted.**

Ergon Energy confirms that the spans in network service areas where Ergon Energy is not responsible have not been counted.

**16.6 "Total number of spans" (DOEF0205) does not include service line spans.**

Ergon Energy confirms that the total number of spans does not include service spans.

**16.7 Ergon Energy must report the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length (this is the total feeder route line length for all CBD, urban, short rural and long rural feeders) against "Rural proportion" (DOEF0201).**

Ergon Energy has reported that route line length of feeders (classified between either long or short) by the total route feeder line length.

**16.8 For the purposes of calculating the "Route line length" variable (DOEF0301) or other variables measured in terms of route line length:**

**(a) The length of service lines are not to be counted**

**(b) the length of a span that shares multiple voltage levels is only to be counted once**

**(c) the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately**

Ergon Energy confirms that the route line length variable has been calculated in accordance with the above instructions.

**16.9 All forecast variables in the Economic Benchmarking *regulatory templates* must correspond with equivalent variables (or derivations of them) in Ergon Energy's *regulatory proposal*. For the avoidance of doubt this includes forecast:**

**(a) opex and capex;**

**(b) *Maximum demand*, *customer* numbers, Energy delivery;**

**(c) Revenues;**

**(d) quality of services variables including SAIDI and SAIFI; and**

**(e) Quantities of physical assets**

Ergon Energy confirms that all forecast variables in the Economic Benchmarking regulatory templates corresponds with equivalent variables in Ergon Energy's Regulatory Proposal.

**16.10 RAB asset financial data in the Assets (RAB) regulatory template must reconcile to that in Ergon Energy's regulatory proposal PTRM and RFM.**

Ergon Energy confirms that the financial data in the Assets (RAB) regulatory template reconciles to that in Ergon Energy's regulatory proposal PTRM and RFM for Standard Control Services and Alternative Control Services.

# 17. PROVISIONS

**17.1 For each of Ergon Energy's provisions, provide the information required in regulatory template 2.13 in accordance with:**

**(a) regulatory template 2.13; and**

**(b) Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.**

Refer to regulatory template 2.13. Ergon Energy confirms that the information provided accords with Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.

**17.2 Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.**

**(a) the expected timing of any resulting outflows of economic benefits;**

In respect of the following provisions:

- 2013 Restructuring Provision – Ergon Energy expected economic outflows to occur in the following year (2014)
- 2008-09 Provision – Ergon Energy expected economic ouflows to occur in 2009-10 and 2010-11.

**(b) an explanation of the uncertainties about the amounts or timing of the outflows;**

In respect of the following provisions:

- 2013 Restructuring Provision – Ergon Energy was uncertain as to the number of staff whose jobs would be made redundant, and to the value of redundancy payments to be made
- 2008-09 Provision – Ergon Energy was unable to be certain of the timing of rehabilitation works required at certain sites.

**(c) any supporting consultant's advice, including actuarial reports; and**

Not applicable.

**(d) if there is no supporting consultant's advice, the process and assumptions Ergon Energy used in determining the increase in the provision.**

In house environmental teams and finance teams determined the estimated value to be provided for in respect of each relevant provision.

Refer to the Basis of Preparation document accompanying regulatory template 2.13.

**17.3 Provide the allocation of the movement in total provisions in, regulatory template 2.13.2 to:**

**(a) Opex;**

Refer to regulatory template 2.13.

**(b) as-incurred capex by roll forward model asset class; and**

Refer to regulatory template 2.13.

**(c) other, where the movement in the provision is neither capex nor opex.**

Refer to regulatory template 2.13.

**17.4 Identify and explain any assumptions applied for the allocation of asset class provided under paragraphs 17.3(b).**

Refer to the Basis of Preparation document accompanying regulatory template 2.13.

# 18. FORECAST PRICE CHANGES

**18.1 Provide, in regulatory template 2.14, the labour and material price changes assumed by Ergon Energy in estimating Ergon Energy's forecast capex proposal and the forecast opex proposal. All price changes must be expressed in percentage year on year real terms.**

The response to regulatory template 2.14 has been provided in accordance with the above requirements.

**18.2 Provide:**

**(a) the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;**

Ergon Energy engaged Jacobs to provide real price escalation forecasts for each Asset Class in the Post Tax Revenue Model. Refer to the spreadsheet "Ergon Energy installed escalator model ver 3a (Ergon release)" attached to the Reset RIN Basis of Preparation for regulatory template 2.14 and Regulatory Proposal attachment 06.02.02 Cost Escalation Factors 2015-20 in which Jacobs explains the process they used to generate the price forecasts.

**(b) in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and**

Refer to Schedule 1 Response attachment 0C.04.05 Ergon Energy Union Collective Agreement 2011.

**(c) evidence that the forecast price changes accurately explain the change in the price of goods and services purchased by Ergon Energy, including evidence that any materials price forecasting method explains the price of materials previously purchased by Ergon Energy.**

Refer to the Regulatory Proposal attachment 06.02.02 Cost Escalation Factors 2015-20.

**18.3 In Ergon Energy's Basis of preparation document(s), provide a written explanation of:**

**(a) the methodology underlying the calculation of each price change, including:**

**(i) sources;**

**(ii) data conversions;**

**(iii) the operation of any model(s) provided under paragraph18.2(a); and**

**(iv) the use of any assumptions such as lags or productivity gains;**

**(b) whether the same price changes have been used in developing both the Forecast capex Proposal and forecast opex proposal; and**

**(c) if the response to paragraph 18.3(b) is negative, why it is appropriate for different expenditure escalators to apply.**

Refer to the Regulatory Proposal attachment 06.02.02 Cost Escalation Factors 2015-20.

**18.4 If an agreement provided in response to paragraph 18.2(b) is due to expire during the Forthcoming regulatory control period, explain the progress and outcomes of any negotiations to date to review and replace the current agreement.**

Ergon Energy's current enterprise agreement nominally expires on 1 October 2014. The enterprise agreement will continue to apply beyond the nominal expiry date until replaced or terminated in accordance with law. Ergon Energy has initiated bargaining in August with industry unions as default bargaining representatives for a new enterprise agreement following formal approval from the Queensland Government on its bargaining framework and in compliance with the Government Owned Corporation (GOC) Wages Policy 2012.

In accordance with the GOC Wages Policy requirements Ergon Energy may provide a wage increase up to a maximum of three (3) per cent per annum with the increase off-set by efficiencies gained from a combination of simplification measures and productivity improvement cost savings.

Negotiations for a new enterprise agreement remain ongoing with the parties continuing to work through initial claims. To date there have not been any agreed outcomes from bargaining with any in-principle agreement reached subject to the overall negotiated outcome.

# 19. RELATED PARTY TRANSACTIONS

**19.1 Identify and describe all entities which:**

**(a) are a related party to Ergon Energy;**

Related parties are:

- Ergon Energy Queensland Pty Ltd (EEQ). The principal activity of EEQ is non-contestable electricity retailing in regional Queensland.
- Ergon Energy Telecommunications Pty Ltd (EET). The principal activity of EET is the provision of wholesale communications services in Queensland on a non-exclusive basis to carriers and carriage service providers, as well as internally to Ergon Energy Corporation Limited and its controlled entities.
- SPARQ Solutions Pty Ltd (SPARQ). The principal activity of SPARQ was to act as the information Communications and Technology (ICT) Service Provider to its clients Ergon Energy Corporation Limited and Energex.

**(b) are a related party to Ergon Energy and contribute to the provision of distribution services; or**

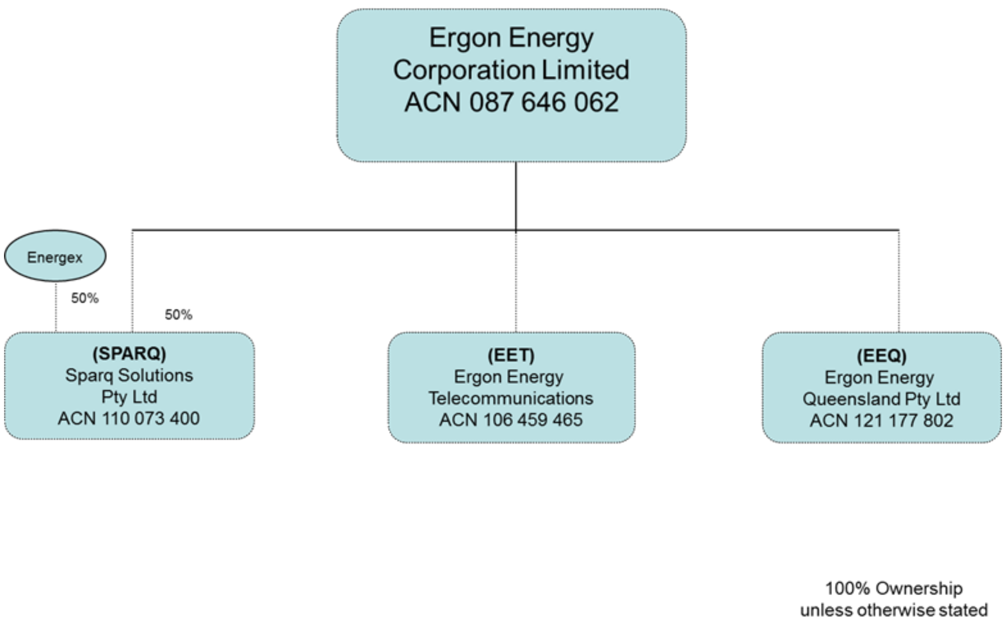
EET and SPARQ (refer 19.1 (a)).

**(c) have the capacity to determine the outcome of decisions about Ergon Energy's financial and operating policies.**

Not applicable.

**19.2 Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 19.1.**

**Ergon Energy Group Structure**



**19.3 Identify:**

**(a) all arrangements or contracts between Ergon Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services; and**

EET: agreements or contracts include the Agreement Supporting the Operations of Ergon Energy Telecommunications Pty Ltd with additional subsidiary Service Schedules – refer to Schedule 1 Response attachment 0C.04.06 Agreement Supporting the Operations of EET.

SPARQ: agreements or contracts include the Ergon Energy Service Level Agreement 2013 2014 (SLA) and EE Multi Option Facility Agreement (MOFA) – refer to Schedule 1 Response attachments 0C.04.07 Ergon Energy Service Level Agreement 2013-14 and 0C.04.08 EE Multi Option Facility Agreement.

**(b) the service or services the subject of each arrangement or contract.**

EET: Services are:

- EET pays EECL for usage of EECL's communications infrastructure
- EECL will act as a contractor for EET for the installation and maintenance of the assets activated for EET
- EET appoints EECL as the provider of EET Business Management services (incorporating general, commercial, regulatory and marketing and sales management)
- EECL will provide Financial and Corporate Services to EET
- EECL will provide Network Management Services to EET. These services will compromise all activities necessary to support the EET network
- EET will provide to EECL the Internal Communication Services.

SPARQ: Services provided under the SLA include

- End User Services
- Telecommunication Services
- Procurement Services
- Procurement
- Project Based Services
- ICT Work Requests
- Business Application Services
- Data Centre Services
- Corporate Services.

Services provided under the MOFA include EECL providing SPARQ with funding facilities.

**19.4 For each service identified in the response to paragraph 19.3(b)**

**(a) Provide:**

**(i) a description of the process used to procure the service; and**

EET: Procurement process agreed in the Agreement Supporting the Operations of Ergon Energy Telecommunications Pty Ltd – refer to Schedule 1 Response attachment 0C.04.06 Agreement Supporting the Operations of EET.

SPARQ: agreements or contracts include the Ergon Energy Service Level Agreement 2013 2014 (SLA) and EE MOFA (MOFA) – refer to Schedule 1 Response attachments 0C.04.07 Ergon Energy Service Level Agreement 2013-14 and 0C.04.08 EE Multi Option Facility Agreement.

**(ii) supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ergon Energy and the relevant provider;**

EET: Attached is the Agreement Supporting the Operations of Ergon Energy Telecommunications Pty Ltd as well as a completed example Service Schedule – refer to Schedule 1 Response attachments 0C.04.06 Agreement Supporting the Operations of EET and 0C.04.09 Completed example Service Schedule.

SPARQ: Attached is the Ergon Energy Service Level Agreement 2013 2014 (SLA) and EE Multi Option Facility Agreement (MOFA) – refer to Schedule 1 Response attachments 0C.04.07 Ergon Energy Service Level Agreement 2013-14 and 0C.04.08 EE Multi Option Facility Agreement.

**(b) explain:**

**(i) why that service is the subject of an arrangement or contract (i.e. why it is outsourced) instead of being undertaken by Ergon Energy itself;**

EET was established to provide any excess telecommunications capacity on the EECL network to carriers and carriage service providers on a wholesale, non-exclusive basis.

SPARQ was established as a vehicle to share information communications and technology (ICT) costs between Ergon and Energex while still obtaining acceptable service levels.

**(ii) whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement (or similar);**

EET: services are procured under the Agreement Supporting the Operations of Ergon Energy Telecommunications Pty Ltd with additional subsidiary Service Schedules – refer to Schedule 1 Response attachments 0C.04.06 Agreement Supporting the Operations of EET.

SPARQ: services are procured under the Ergon Energy Service Level Agreement 2013 2014 (SLA) and EE Multi Option Facility Agreement (MOFA) – refer to Schedule 1 Response attachments 0C.04.07 Ergon Energy Service Level Agreement 2013-14 and 0C.04.08 EE Multi Option Facility Agreement.

**(iii) whether the services were procured on a genuinely competitive basis and if not, why; and**

EET: Services have been provided on a competitive basis.

SPARQ: Services have been provided on a competitive basis.

**(iv) whether the service (or any component thereof) was further outsourced to another provider.**

EET: Services provided by EET to EECL (EECL internal communications services) were outsourced to third parties.

SPARQ: Services were generally not further outsourced.

# 20. PROPOSED CONTINGENT PROJECTS

**20.1 For each contingent project proposed in the regulatory proposal, provide:**

**(a) a description of the proposed contingent project, including reasons why Ergon Energy considers the project should be accepted as a contingent project for the forthcoming regulatory control period;**

**(b) the proposed contingent capital expenditure which Ergon Energy considers is reasonably required for the purpose of undertaking the proposed contingent project;**

**(c) the methodology used for developing that forecast and the key assumptions that underlie it;**

**(d) information that demonstrates that the undertaking of the proposed contingent project is reasonably required to meet one or more of the objectives referred to in clause 6.6A.1(b)(1) of the NER;**

**(e) a demonstration that the proposed contingent capital expenditure for each proposed contingent project:**

**(i) is not included (either in part of in whole) in Ergon Energy's proposed total forecast capital expenditure for the forthcoming regulatory control period;**

**(ii) reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of the proposed contingent project; and**

**(iii) exceeds either $30 million ($nominal) or 5 per cent of Ergon Energy's proposed annual revenue requirement for the first year of the forthcoming regulatory control period, whichever is larger amount.**

**(f) the proposed trigger events relating to the proposed contingent project.**

Refer to Regulatory Proposal attachment 07.09.16 Contingent Projects.

**20.2 For each proposed trigger event relating to the proposed contingent project referred to in 0, demonstrate:**

**(a) the proposed trigger event is reasonably specific and capable of objective verification**

**(b) the occurrence of the proposed trigger event makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives;**

**(c) the proposed trigger event generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole;**

**(d) the proposed trigger event is described in such terms that the occurrence of that event or condition is all that is required for the distribution determination to be amended under clause 6.6A.2 of the NER;**

**(e) the proposed trigger event is a condition or event, the occurrence of which is probable during forthcoming regulatory control period, but the inclusion of capital expenditure in relation to the proposed trigger event under clause 6.5.7 of the NER is not appropriate because:**

**(i) it is not sufficiently certain that the event or condition will occur during the forthcoming regulatory control period or if it may occur after that regulatory control period or not at all; or**

**(ii) the costs associated with the event or condition are not sufficiently certain.**

Refer to Regulatory Proposal attachment 07.09.16 Contingent Projects.

**20.3 Provide a summary of Ergon Energy's proposed contingent projects for the forthcoming regulatory control period including the proposed contingent capital expenditure and trigger events for each proposed contingent project in the regulatory template 7.2.**

Ergon Energy confirms it has provided a response to regulatory template 7.2.

# 21. NON-NETWORK ALTERNATIVES

**21.1 Identify the Policies and Strategies and Procedures which relate to the selection of efficient non-network solutions.**

Ergon Energy Policies, Strategies and Procedures relating to the selection of efficient non-network solutions are provided in the following documents, with section references provided:

- Regulatory Proposal attachment 07.02.11 Demand Management Overview 2015 to 2020. Refer to sections:
  - 6.2 Demand management drivers
  - 7 Demand management operational strategy
  - 8 Strategic initiatives
  - 9 Demand Management Plan 2015-2020
  - Appendix B
    - NA0009 – Plan network investments
    - NA000904 – Conduct annual planning review
    - NA0009906 – Conduct regulatory investment test.
- Regulatory Proposal attachment 07.02.06 Demand Management Plan.

**21.2 Explain the extent to which the provision for efficient non-network alternatives has been considered in the development of the forecast capex proposal and the forecast opex proposal.**

The extent to which the provision for efficient non-network alternatives has been considered in the development of the forecast capex and forecast opex proposal is explained the following document:

- Regulatory Proposal attachment 07.02.11 Demand Management Overview 2015 to 2020. Refer to sections:
  - 7.3 Demand management impacts
  - 6.4 Demand management success.

**21.3 Identify each non-network Project that Ergon Energy has:**

**(a) commenced during the current regulatory control period; and**

Ergon Energy non-network Projects in the current regulatory Control period (2010 to 2015) are identified in:

- Regulatory Proposal attachment 07.02.11 Demand Management Overview 2015 to 2020. Refer to sections:
  - 9.6 Demand Management Innovation Allowance (DMIA) (page 35)
  - 9.7 Demand management portfolio summary (page 37)
- Schedule 1 Response attachment 0C.04.10 DM Outcomes 2010-11
- Schedule 1 Response attachment 0C.04.11 DM Outcomes 2011-12

- Schedule 1 Response attachment 0C.04.12 DM Outcomes 2012-13
- Schedule 1 Response attachment 0C.04.13 DM Outcomes 2013-14.

**(b) selected to commence during, or will continue into, the Forthcoming regulatory control period.**

Ergon Energy non-network Projects that have been selected to commence during, or will continue into, the Forthcoming Regulatory Control period (2015 to 2020) are identified in:

- Regulatory Proposal attachment 07.02.11 Demand Management Overview 2015 to 2020. Refer to section:
  - o 9.7 Demand management portfolio summary (at page 37).

**21.4 For each non-network Project identified in the response to paragraph 21.3, provide a description, including cost and location.**

Ergon Energy provides information for each non-network project identified in the response to paragraph 21.3 including description, cost and location in the following document:

- Regulatory Proposal attachment 07.02.11 Demand Management Overview 2015 to 2020. Refer to sections:
  - o 7.5 Demand management innovation allowance (atpage 35)
  - o 7.6 Demand management portfolio summary (at page 37).
- Schedule 1 Response attachment 0C.04.10 DM Outcomes 2010-11
- Schedule 1 Response attachment 0C.04.11 DM Outcomes 2011-12
- Schedule 1 Response attachment 0C.04.12 DM Outcomes 2012-13
- Schedule 1 Response attachment 0C.04.13 DM Outcomes 2013-14.

**21.5 Provide, for each year of the current regulatory control period, and for the forthcoming regulatory control period, details of each payment made, or expected to be made, by Ergon Energy to an Embedded Generator in reflection any costs avoided by deferring augmentation of:**

**(a) Ergon Energy's distribution network; or**

Ergon Energy provides, information on payments made, or expected to be made, by Ergon Energy to an Embedded Generator in reflection any costs avoided by deferring augmentation of Ergon Energy's distribution network in the following document:

- Regulatory Proposal attachment 07.02.11 Demand Management Overview 2015 to 2020. Refer to sections:
  - o 9.9 Payments to embedded generators (at page 43)
  - o 9.10 Forecast payments to embedded generators.

Payments made to generators and forecast to be made to embedded generators for the 2015-2020 regulatory control period are detailed in the Schedule 1 Response attachment 0C.04.14 NNA_Embedded Generator Payments_CONFIDENTIAL

In accordance with the AER's Confidentiality Guideline Ergon Energy claims confidentiality over all information in Schedule 1 attachment 0C.04.14 as it contains market sensitive information with details relating to dedicated customer contracts that may be covered by confidentially clauses in the customer contracts.

**(b) the relevant transmission network.**

Not applicable.

# 22. EFFICIENCY BENEFIT SHARING SCHEME

**22.1 To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Ergon Energy's current regulatory control period:**

**(a) provide the forecast and actual operating expenditure amounts in regulatory template 7.5;**

All forecast and actual operating expenditure amounts have been provided in regulatory template 7.5.

**(b) identify all changes to Ergon Energy's Capitalisation Policy during the current regulatory control period.**

No changes were identified to Ergon Energy's Capitalisation Policy during the current regulatory control period.

**22.2 For each change identified in the response to paragraph 22.1(b):**

**(a) state, if any, the financial impact of the change;**

**(b) state the reasons for the change;**

**(c) explain the effect of the change, if any, on the forecast operating expenditure for each year of Ergon Energy's current regulatory control period; and**

**(d) explain the effect of the change, if any, on the actual operating expenditure for each year of Ergon Energy's current regulatory control period.**

Not applicable.

**22.3 For the purposes of applying the efficiency benefit sharing scheme:**

**(a) identify all cost categories proposed to be excluded from the operation of the efficiency benefit sharing scheme;**

Only the cost of Parametric Insurance has been added to the Insurance cost category exclusion identified in the AER Determination for the period 2010-2015.

**(b) explain for each cost category identified in the response to paragraph 22.3(a) the reasons for the proposed exclusion.**

Parametric Insurance is excluded for the same reasons the AER gave for excluding Insurance costs in the Queensland Draft Distribution Determination 2010-11 to 2014-2015, 25 November 2009, section 13.5.2, page 312. Parametric Insurance has been included in the Insurance category for the forecast period in the regulatory template 7.5.2.

# 23. SERVICE AND QUALITY

**23.1 Provide Ergon Energy's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS):**

**(a) the SAIDI and SAIFI targets for each supply reliability area;**

Refer to section 4.3.2 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

**(b) the customer service parameters and targets;**

Refer to section 3.3.3 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

**(c) daily SAIDI, SAIFI and customer service performance derived from the individual interruption data under 23.2;**

Refer to section 4.3.1 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

**(d) the MED threshold derived from the daily SAIDI data;**

Refer to section 4.2.2 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

**(e) the incentive rates to apply to each supply reliability area.**

Refer to section 4.3.3 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

**Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.**

**23.2 If Ergon Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Ergon Energy must provide, in respect of each adjustment:**

**(a) the reasons for the adjustment;**

Refer to section 4.3.2 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20

**(b) the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and**

Refer to section 4.3.2.3 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

**(c) the method, basis and empirical data used as justification for the adjustment.**

Refer to section 4.3.2.1 and 4.3.2.3 of Regulatory Proposal attachment 03.02.02 Proposed Application of STPIS 2015-20.

# 24. SHARED ASSETS

**24.1 Provide Ergon Energy's shared assets information in regulatory template 7.4.**

Ergon Energy confirms that it has provided the relevant information in the regulatory template.

# 25. REVENUES AND PRICES FOR STANDARD CONTROL SERVICES

**25.1 Provide Ergon Energy's calculation of the unsmoothed and smoothed revenues, and prices for the purposes of the control mechanism proposed by Ergon Energy using the *AER*'s *post-tax revenue model*, which is to be submitted as part of the *regulatory proposal*.**

Please refer to Ergon Energy's population of the AER's PTRM, a supporting document to Ergon Energy's Regulatory Proposal which calculates both the smoothed and unsmoothed revenues for the purpose of the revenue cap control mechanism determined by the AER in its Framework and Approach Paper.

Additionally, please refer to:

- Regulatory Proposal attachment 04.01.00 Compliance with Control Mechanisms for an explanation of how we propose to comply with the AER's control mechanism and determined formula.
- Supporting model at Regulatory Proposal attachment 04.01.05 Control Mechanism Model, which provides a more detailed explanation of the method we expect the AER will apply to ensure Ergon Energy complies with the AER's control mechanism for the 2015-20 period.

**25.2 Provide details of each departure from the AER's *post-tax revenue model* for the calculations referred in paragraph 25.1 and the reasons for that departure.**

Section 8.2 of our Regulatory Proposal attachment 03.01.01 Building Blocks Components provides the necessary details of our approach to compliance with NER clause 6.3.1(c)(1), which includes the need to provide a building block proposal in accordance with the AER's PTRM.

# 26. INDICATIVE IMPACT ON ANNUAL ELECTRICITY BILLS

**26.1 For the purposes of calculating the impact of Ergon Energy's Regulatory proposal on the annual electricity bill of typical residential and business customers in Queensland, provide the data/information required in *regulatory template* 7.6. Provide the data source for each input used for the calculation.**

An explanation of the data / information used to populate input cells in regulatory template 7.6 is outlined below.

Please note the following information relates to the cells required by the AER for Ergon Energy to populate. We do not believe that the consequential calculation is a misleading representation of the consequential impact of our revenue on a customer's bill as assumes only one tariff component (volume) in the calculation.

### Distribution costs as a proportion of a typical customer's electricity bill (per cent)

The proportion of distribution costs as % of total electricity bill will vary depending on customer type, location and consumption. It is also dependent on whether the customer is subject to regulated retail arrangements (such as Notified Prices in Queensland) or on a market retail contract. For the purposes of ease of calculation, we have used 50% which is reasonable approximation given the diverse range distribution costs for residential customers across regional Queensland. This percentage also aligns with our estimate of the proportion of distribution costs (excluding feed-in-tariff recoveries) contributing to the total electricity bill of a typical residential customer on a market retail contract in the 2015-16 regulatory year (as set out in section 1.1 of our Regulatory Proposal). Our indicative analysis also suggests that the proportion of distribution costs contributing to the total electricity bill for a small business customer would be of similar magnitude.

### Typical electricity bill – residential customer

Our estimates of the typical electricity bill for a residential customer in our Regulatory Proposal and in template 7.6 are based on the following data:

- Actual and forecast Total Allowable Revenue as set out in in Regulatory Proposal attachment 04.01.05 Control Mechanism Model and within regulatory template 7.6 (forecast smoothed revenues)
- Forecast energy and customer numbers as outlined in our 2014-15 Pricing Proposal and our 2015-20 Regulatory Proposal
- Forecast revenues allocated to our Residential Inclining Block network tariff in each of our respective pricing zones (East, West and Mount Isa). These allocations are consistent with the pricing methodologies outlined in our AER-approved annual Pricing Proposal for the 2014-15 year

The underlying assumptions around annual consumption to calculate annual bills for each of the tariff types are set out in regulatory template 7.6 (description of tariff type) and summarised below:

| Tariff type | Description of tariff type |
|---|---|
| Domestic electricity bill - East - Inclining Block Tariff | The Inclining Block residential tariff is based on 4,700 kilowatt hours (kWh) consumption per year. This use is the average for a domestic consumer in this Zone. |
| Domestic electricity bill - West - Inclining Block Tariff | The Inclining Block residential tariff is based on 6,600 kilowatt hours (kWh) consumption per year. This use is the average for a domestic consumer in this Zone. |
| Domestic electricity bill - Mt Isa - Inclining Block Tariff | The Inclining Block residential tariff is based on 8,500 kilowatt hours (kWh) consumption per year. This use is the average for a domestic consumer in this Zone. |

### Typical electricity bill – business customer

Our estimates of the typical electricity bill for a business customer in template 7.6 are based on the following data:

- Actual and forecast Total Allowable Revenue as set out in in Regulatory Proposal attachment 04.01.05 – Standard Control Services Control Mechanism Model and within regulatory template 7.6 (forecast smoothed revenues)
- Forecast energy and customer numbers as outlined in our 2014-15 Pricing Proposal and our 2015-20 Regulatory Proposal
- Forecast revenues allocated to our Business Inclining Block network tariff in each of our respective pricing zones (East, West and Mount Isa). These allocations are consistent with the pricing methodologies outlined in our AER-approved annual Pricing Proposal for the 2014-15 year
- The underlying assumptions around annual consumption to calculate annual bills for each of the tariff types are set out in regulatory template 7.6 (description of tariff type) and summarised below:

| Tariff type | Description of tariff type |
|---|---|
| Business electricity bill - East - Inclining Block Tariff | The Inclining Block business tariff is based on 8,500 kilowatt hours (kWh) consumption per year. This use is the average for a business consumer in this Zone. |

| Tariff type | Description of tariff type |
|---|---|
| Business electricity bill - West - Inclining Block Tariff | The Inclining Block business tariff is based on 14,400 kilowatt hours (kWh) consumption per year. This use is the average for a business consumer in this Zone. |
| Business electricity bill - Mt Isa - Inclining Block Tariff | The Inclining Block business tariff is based on 12,700 kilowatt hours (kWh) consumption per year. This use is the average for a business consumer in this Zone. |

### Forecast smoothed revenues

As noted above, Ergon Energy has relied actual and forecast Total Allowable Revenues generated for the Regulatory Proposal as set out in Regulatory Proposal attachment 04.01.05 Control Mechanism Model.

### Energy delivered forecasts

Energy delivered forecasts are based on our energy and demand forecasts we have produced for our Regulatory Proposal and this RIN response.

# 27. REGULATORY ASSET BASE

**27.1 Provide Ergon Energy's calculation of the regulatory asset base for the relevant distribution system in respect of standard control services for each regulatory year of current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.**

Refer to section 2.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**27.2 Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred in 27.1 and the reasons for that departure.**

Refer to section 2.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**27.3 If the value of the regulatory asset base as at the start of the forthcoming regulatory control period is proposed to be adjusted because of changes to asset service classification, provide details including relevant supporting information used to calculate that adjustment value.**

Refer to section 2.1.4 of Regulatory Proposal attachment 03.01.01 Building Blocks Components and 05.03.01 Default Metering Services Summary Document.

**27.4 When reporting the value of its regulatory asset base for regulatory years prior to 2015-16, including forecasting this value for 2014-15, Ergon Energy is not required to make adjustments for the new cost allocation method and service classifications to take effect from 1 July 2015.**

Not applicable.

# 28. DEPRECIATION SCHEDULES

**28.1 Provide Ergon Energy's calculation of the depreciation amounts for the relevant distribution system in respect of standard control services for each regulatory year of:**

**(a) the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal**

Refer to Regulatory Proposal attachment 03.01.06 SCRFM Data Model.

**(b) the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.**

Refer to Regulatory Proposal attachment 03.01.04 SCPTRM Data Model AER May 2014.

**28.2 Provide details of each departure from the underlying methods in the AER's roll forward model and post-tax revenue model for the calculations referred to in 28.1 and the reasons for that departure.**

Refer to section 8.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**28.3 Identify each change to standard asset lives for existing asset classes from the previous determination. Explain the reason(s) for the change and provide relevant supporting information.**

Refer to section 4.2.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**28.4 For each proposed new asset class, explain the reason(s) for using these new asset classes and provide relevant supporting information on their proposed standard asset lives.**

Refer to section 4.2.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components and Regulatory Proposal attachment 05.03.01 Default Metering Services Summary Document.

**28.5 If existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes, explain the reason(s) for the change and provide relevant supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.**

Refer to section 2.1.5.3 of Regulatory Proposal attachment 03.01.01 Building Blocks Components and Regulatory Proposal attachment 05.03.01 Default Metering Services Summary Document.

**28.6 Describe the method used to calculate the remaining asset lives for existing asset classes as at 1 July 2015 (the start of the forthcoming regulatory control period) and provide supporting calculations if the approach differs from that in the roll forward model.**

Refer to section 4.2.2 of Regulatory Proposal attachment 03.01.01 Building Blocks Components and Regulatory Proposal attachment 05.03.01 Default Metering Services Summary Document.

# 29. CORPORATE TAX ALLOWANCE

**29.1 Provide Ergon Energy's calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.**

Refer to section 6 of Regulatory Proposal attachment 03.01.01 Building Blocks Components. The issue of gifted assets is covered in section 6.1.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.2 Provide a demonstration that the calculation referred to in 29.1 complies with clause 6.5.3 of the NER.**

Refer to section 6 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.3 Provide details of each departure from the AER's post-tax revenue model for the calculations referred to in 29.1 and the reasons for that departure.**

Refer to section 6.1 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.4 Identify each change to standard tax asset lives for existing asset classes from the previous determination. Explain the reason(s) for the change and provide relevant supporting information, including Federal tax laws governing depreciation for tax purposes.**

Refer to section 4.2.3 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.5 Describe the method used to calculate the remaining tax asset lives as at 1 July 2015 and provide supporting calculations, if the approach differs from that in the AER's roll forward model.**

Refer to section 4.2.4 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.6 Provide Ergon Energy's calculation of the tax asset base for the relevant distribution system in respect of standard control services for each regulatory year of the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.**

Refer to section 2.4 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.7 Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred to in 29.6 and the reasons for that departure.**

Refer to section 2.4.4 of Regulatory Proposal attachment 03.01.01 Building Blocks Components.

**29.8 Identify each difference in the capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes. Provide reasons and supporting calculations to reconcile any differences between the two forms of accounts.**

The expenditure capitalised for regulatory accounting purposes differs to that capitalised for tax purposes due to the immediate tax deductibility of capitalised interest and overheads, including stores on-costs. That is, the opening tax value of a newly capitalised asset is equal to the opening regulatory accounting value less any capitalised interest, overheads and stores on-costs.

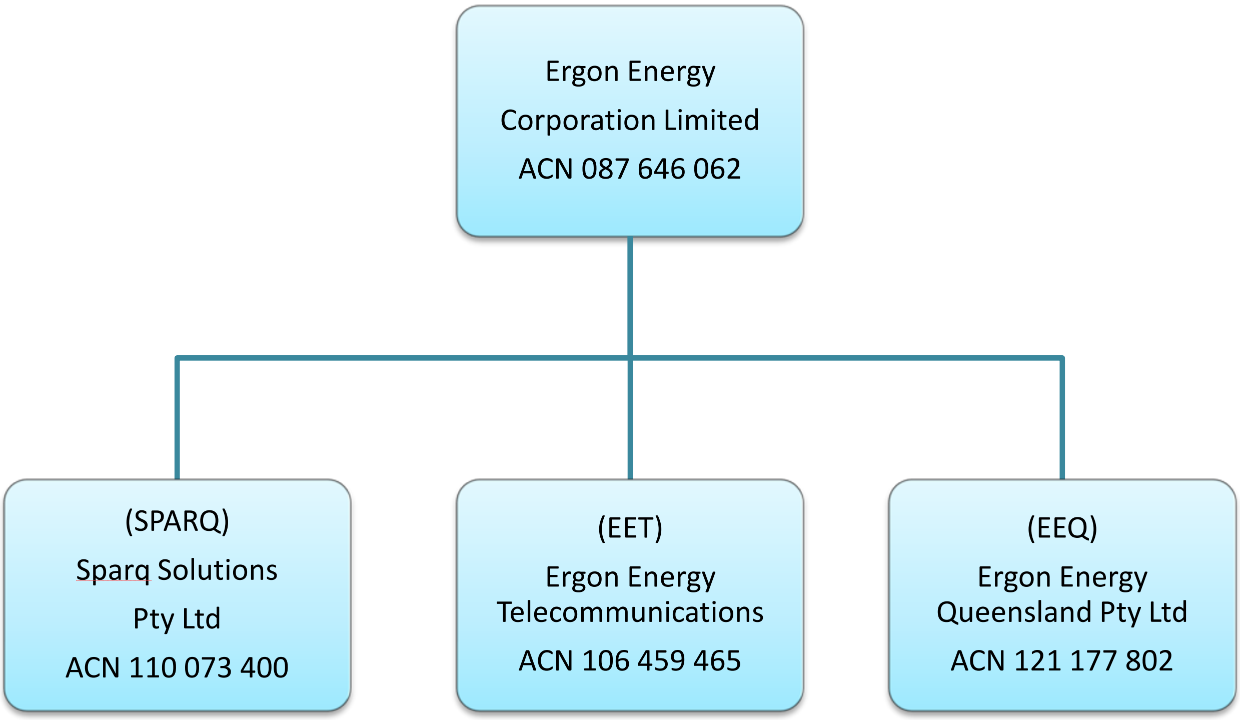
**29.9 Provide calculations to demonstrate if a tax loss carried forward will exist as at 1 July 2015. The figures used in these calculations, such as the revenue and operating expenses, should be actuals (with the exception of the final year of the current regulatory control period that requires an estimate). Identify and provide reasons for any assumptions applied to determine the value of any tax loss carried forward.**

Ergon Energy confirms that no tax loss will be carried forward to 1 July 2015.

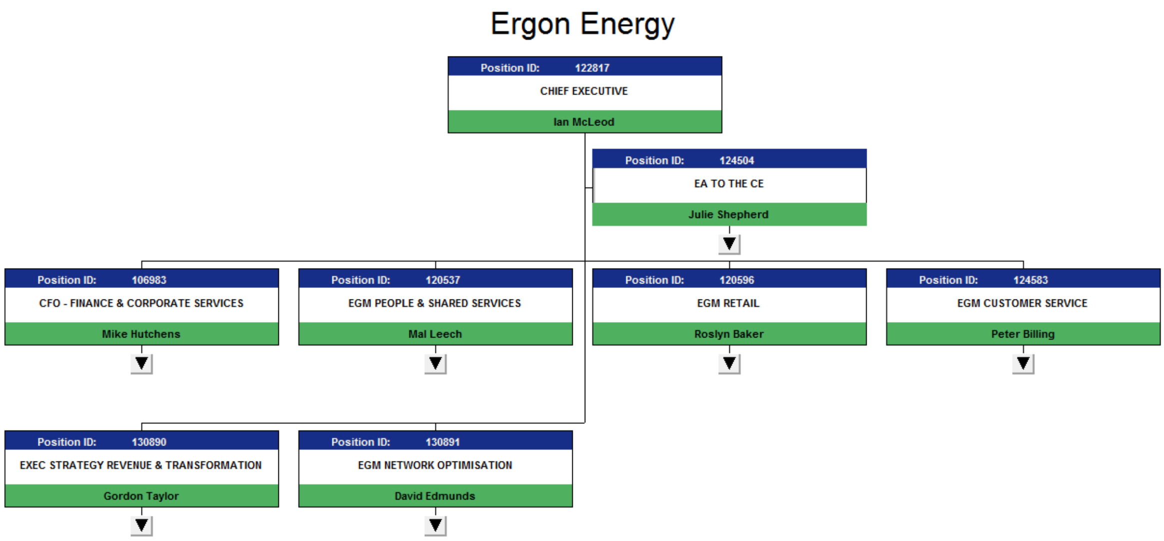
# 30. CORPORATE STRUCTURE

**30.1 Provide charts that set out:**

**(a) the group corporate structure of which Ergon Energy is a part; and**




**(b) the organisational structure of Ergon Energy.**



# 31. FORECAST MAP OF DISTRIBUTION SYSTEM

**31.1 Provide a forecast map of Ergon Energy's distribution system for the forthcoming regulatory control period. This map, together with any appropriate accompanying notes, should also indicate the location of new major network assets proposed to be constructed over the forthcoming regulatory control period.**

The maps provided only include the augmentation investments listed in Table 1 that are proposed for the forthcoming regulatory control period (2015-2020) as at the date of our Regulatory Proposal.

This list of investments has been provided in accordance with the instructions and definitions for major investments (material projects) populating regulatory template 2.3 Augex, tables 2.3.1 and 2.3.2 (>$5M Direct Costs $2014/15):

- Table 2.3.1 Augex Asset Data: Subtransmission Substations, Switching Stations and Zone Substations
- Table 2.3.2 Augex Asset Data: Subtransmission Lines.

Although total forecast expenditure for investments augmenting our distribution network comprise a large proportion of our total capital (system) expenditure forecast we have not indicated the location of these investments as individual investments do not meet the materiality threshold specified above.

Regulatory Proposal attachment 07.00.02 Corporation Initiated Augmentation Expenditure Forecast Summary outlines our forecasting process for distribution and subtransmission augmentation. The Regulatory Proposal attachments 07.02.02 Distribution Network Augmentation Plan and 07.02.03 Subtransmission Network Augmentation Plan summarise:

- The projects WIP and forecasted investments for both the distribution and sub transmission network categories;
- Details of the forecasted investment location – Feeder / Substation.

Regulatory Proposal attachment 07.00.08 property Expenditure Forecast summary outlines major works of activity with detail of location and anticipated costs where known, relating to standard control services.

Table 1 provides detail of the forecast major new assets proposed to be constructed over the next regulatory control period.

Figure 1 provides the forecast map of Ergon Energy's distribution system for the forthcoming regulatory control period.

Figure 2 provides a forecast map of Ergon Energy's distribution system for the forthcoming regulatory control period indicating the location of new major assets proposed to be constructed over the forthcoming regulatory control period (refer to Table 1).

Figure 3 provides Mackay Region Major Investment Locations.

Figure 4 provides Rockhampton Region Major Investment Locations.

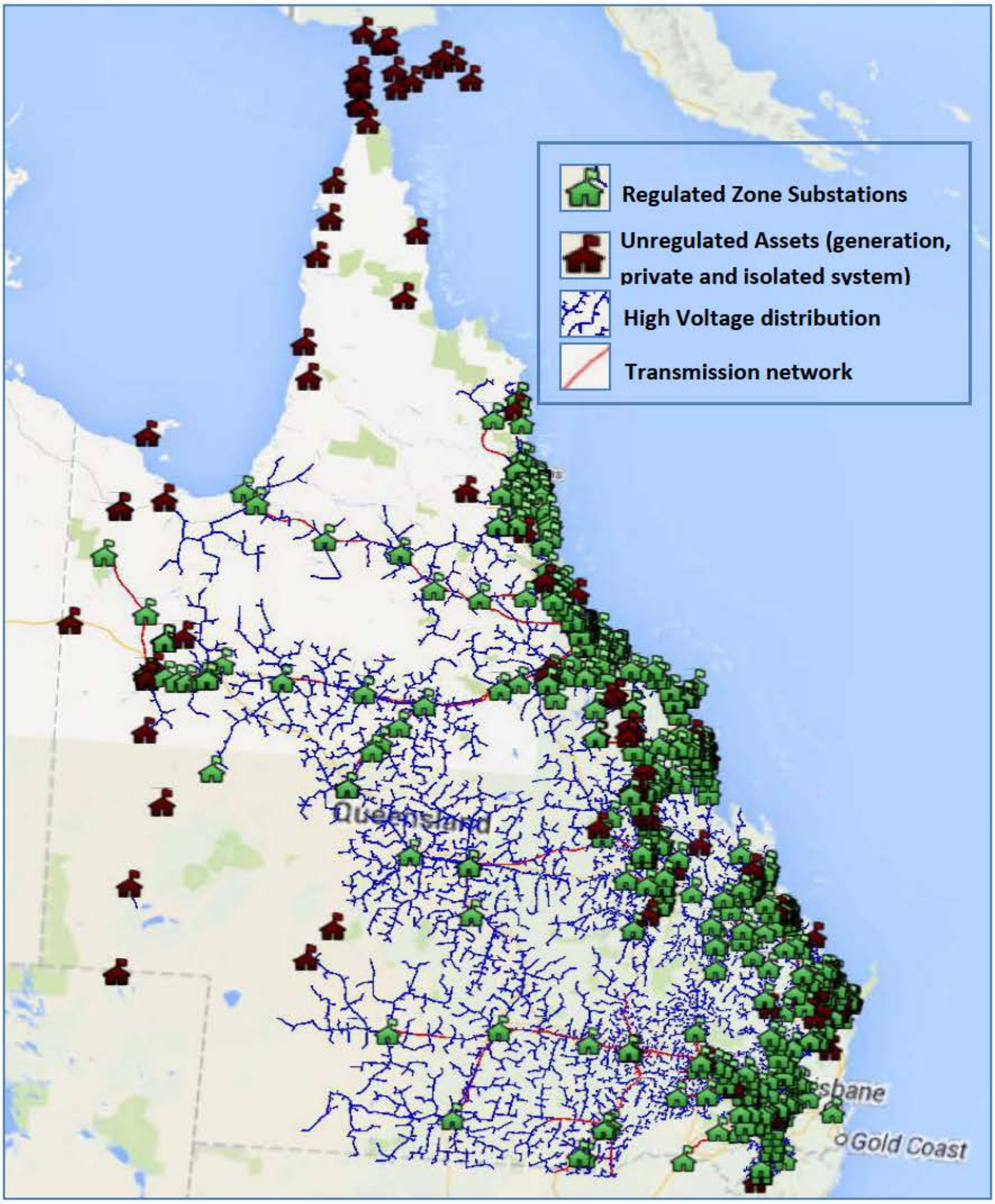
Figure 5 provides Toowoomba Region Major Investment Locations.

**Table 1: New Major Subtransmission Investments (>$5M Direct Costs $2014/15)**

| Map Designator | New Major Investment Description | Work Request Reference Numbers |
|---|---|---|
| A | Emerald Zone Substation - Install 3x3MVAr Cap banks and +/-2MVAr STATCOM, all connected at 22kV side | CPMNN01145 |
| B | Malchi Zone Substation - Gracemere, Modular, 66/11kV, Network, Central | 317031 |
| C | Gladstone South Zone Substation - Briffney Establish new 66/11kV Sub | 693294 |
| D | Moranbah Zone Substation - Modular, 66/11kV, 32MVA, Network, Central | 48821; 48824 |
| E | Planella Zone Substation - Convert to 66/11kV | 48598; DCP18260; DCP16183 |
| F | Dysart 66/22kV Transformers - Install 20MVA 66/22kV TFs; Dysart 66kV TF Bay - Install 66kV TF bay for Powerlink 3rd TF | 552296; 760213 |
| G | Boyne Residential Zone Substation | 311743 |
| H | Cannonvale - Switching Station | 154826 |
| I | Gladstone South - Redevelop existing as 2x20MVA 66/11kV substation | CPMNN01466 |
| J | South Mackay Zone Substation - Ooralea, Modular, Network, Mackay | 48638; 48647; 653444 |
| K | Central Toowoomba Zone Substation - Greenfield, 110/11kV, Network, South West | 140507 |
| L | Charlton Zone Substation - 11kV feeders out of Torrington sub | DCP17784 |
| M | Kumbia 66/11kV Zone Substation Establishment | 141629; 432340; 431150 |
| N | Broxburn Zone Substation - Rebuild as 110/11kV | 316573 |
| O | Toogoom Zone Substation - Construct 66/11kV Zone Substation; Modular 3 11kV feeders | 196710; 196687 |
| P | Roma West Zone Substation - Roma West 33/11kV Transformer & 11kV Switchgear Augment Replace existing TFs & 11kV swyd | 419495 |
| Q | Augment 110/33kV TX at T013 Chinchilla | CPMNS00402 |
| R | Establish Avoca 66/11kV Zone Substation Establish a new Zone Substation at Avoca | 50685 |
| S | Line, South Toowoomba Sub to Central Toowoomba Sub, 110kV, South West | 140221 |
| T | SPD WB AT ISIS T131 OH New to Dallarnil New 37km 132kV SCCP (Energised at 66kV) | 183596; 306794 |

***Forecast map of Ergon Energy's distribution system for the forthcoming regulatory control period (2015-2020) indicating the location of Ergon Energy's transmission network, HV distribution network, regulated and unregulated assets.***

Figure 1: Forecast map of Ergon Energy's distribution system



***Forecast map of Ergon Energy's distribution system for the forthcoming regulatory control period indicting the location of new major assets proposed to be constructed over the forthcoming regulatory control period (2015 – 2020).***

***For greater detail please refer to Figure 3 (Mackay Region); Figure 4 (Rockhampton Region); and Figure 5 (Toowoomba Region).***

**Figure 2: New Major Network Assets >$5M Direct costs ($2014/15)**

**Figure 3: Mackay Region Major Investment Locations**

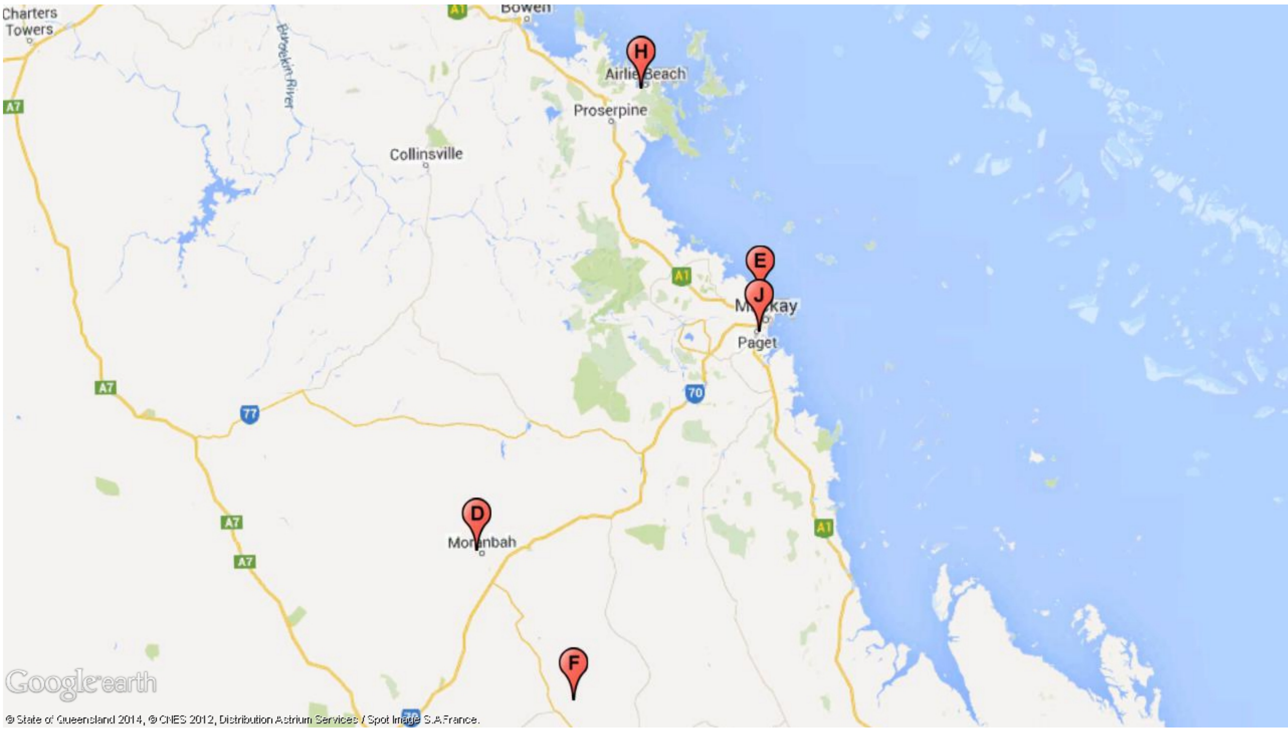



**Figure 4: Rockhampton Region Major Investment Locations**

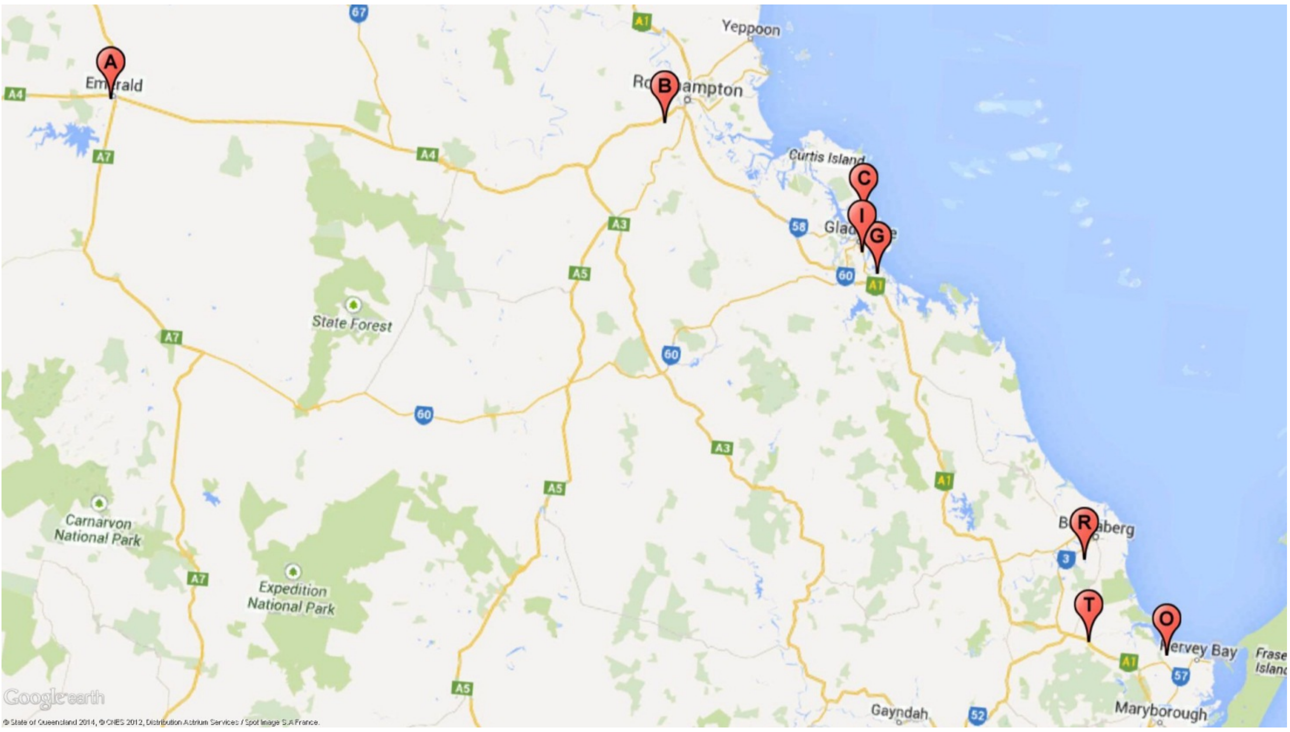


**Figure 5: Toowoomba Region Major Investment Locations**

# 32. AUDIT REPORTS

**32.1 Provide a Regulatory Audit report in the form of:**

**(a) a Special Purpose Financial Report in accordance with the requirements set out at Appendix C; and**

**(b) a Review report (for non-financial information) in accordance with the requirements set out at Appendix C.**

Refer to:

- Reset RIN Submission attachment 0C.01.05 QAO_Reset RIN_Audit and Review Report. Note this report contains the following sections:
  - Actual Historical Financial Information audit report
  - Estimated Historical Financial Information review report
  - Actual and Estimated Historical Non-Financial Information review report
- Reset RIN Submission attachment 0C.01.02 PB Report Review of Reset RIN Non-financial Information.

**32.2 Provide all reports from the Auditor to Ergon Energy's management regarding the audit review and/or auditors' opinions or assessment.**

Ergon Energy confirms that it has provided all Auditor reports to Ergon Energy's management.

# 33. BOARD RESOLUTION

**33.1 Provide proof (such as an extract from the board minutes, or a resolution signed by a necessary majority of directors) that Ergon Energy's board has resolved that, to the best of the Board's information, knowledge and belief, the information provided in the response to paragraph 1.1 (being the information to be provided in the Microsoft Excel Workbooks attached at Appendix A) is:**

**(a) for Actual Information, true and accurate; and**

**(b) where Ergon Energy cannot provide Actual Information, Ergon Energy's best estimate in relation to historical information, or best forecast in relation to forecast information.**

Refer to the Reset RIN Submission 0C.01.03 Reset RIN Board Resolution.

# 34. TRANSITIONAL ISSUES

**34.1 Provide information on transitional issues (expressly identified in the Rules or otherwise) which Ergon Energy expects will have a material impact on it and should be considered by the AER in making its distribution determination. For each issue, set out the following information:**

**(a) the transitional issue;**

Refer to sections 1.3 and 2 of Regulatory Proposal attachment 01.01.02 Effect of Transitional Arrangements.

**(b) what has caused the transitional issue;**

Refer to sections 1.2 and 2 of Regulatory Proposal attachment 01.01.02 Effect of Transitional Arrangements.

**(c) how the transitional issue impacts on Ergon Energy; and**

Refer to section 2 of Regulatory Proposal attachment 01.01.02 Effect of Transitional Arrangements.

**(d) how Ergon Energy considers the transitional issue could be addressed.**

Refer to section 2 of Regulatory Proposal attachment 01.01.02 Effect of Transitional Arrangements.

# 35. CONFIDENTIAL INFORMATION

**35.1 This clause applies to any information Ergon Energy provides:**

**(a) in response to Schedule 1;**

**(b) in a regulatory proposal, revenue proposal, proposed negotiating framework, proposed pricing methodology, access arrangement proposal or access arrangement for the forthcoming regulatory control period (a Proposal)**

**(c) in a revision or amendment to a Proposal; and**

**(d) in a submission Ergon Energy makes regarding a Proposal or a revised or amended Proposal; (together, Ergon Energy's Information).**

**35.2 If Ergon Energy wishes to make a claim for confidentiality over any of Ergon Energy's Information, provide the details of that claim in accordance with the requirements of the AER's Distribution Confidentiality Guideline, as if it extended and applied to that claim for confidentiality.**

**35.3 Provide any details of a claim for confidentiality in response to clause 1.2 at the same time as making the claim for confidentiality. Confirm, in writing, that Ergon Energy consents to the AER disclosing all other of Ergon Energy's Information on the AER website.**

Refer to Regulatory Proposal, Appendix E Approach to Confidential Information and Regulatory Proposal attachment 10.01.01 Confidentiality Template.

# 36. DISPOSALS

**36.1 Ergon Energy must complete sheet x, providing the gross proceeds of sale from disposals for the period 2009-10 to 2014-15 (inclusive).**

Ergon Energy has completed sheet x.  Refer to Reset RIN regulatory templates.