Ergon Energy
Basis of Preparation
Category Analysis RIN

31 October 2019

Table of contents

List of Tables

1 BOP - 2.1 Expenditure Summary

1.1 Scope of BOP

1.1.1 Table 2.1.1 - Standard Control Services Capex

1.1.2 Table 2.1.2 - Standard Control Services Opex

1.1.3 Table 2.1.3 - Alternative Control Services Capex

1.1.4 Table 2.1.4 - Alternative Control Services Opex

1.1.5 Table 2.1.5 - Dual Function Assets Capex

1.1.6 Table 2.1.6 - Dual Function Assets Opex

1.2 Compliance with CA RIN Requirements

- Capital Expenditure reported against activities in Table 2.1.1 have been extracted from individual Templates or derived from information provider supporting files for completion of the templates (where templates didn't require Ergon Energy to distinguish, for example, between capital expenditure (capex) / operational expenditure (opex) and nor Standard Control Services (SCS) or Alternative Control Services. In this regard:
    - ACS for 2018-19 is in line with AER classifications.
    - Public lighting light installation and light replacement have been considered as capex, while light maintenance has been considered as opex.
- In accordance with paragraph 2.4 of the Principles and Requirements an additional Excel spread sheet has been prepared which contains the balancing items reported in Regulatory Template 2.1.
- Ergon Energy has identified balancing items which relate to duplications in reporting expenditure throughout the templates.
- There are no balancing items relating to instances where Ergon Energy has reported capex not on an 'as-incurred' basis. That is to say, where Ergon Energy is required to report in $2018-19 real dollars (Table 2.3.1) in respect of Augex this Table is not relevant to the Expenditure Summary.

In order to create an Expenditure Summary total capex that is mutually exclusive and collectively exhaustive as per RIN requirements, along with populating the balancing line item, Ergon Energy inserted Metering and Public Lighting categories.

Ergon Energy has no dual function assets.

1.3 Sources

Refer to individual Basis of Preparation documents as relevant to the underlying Expenditure reported in templates, as drawn through to populate the Expenditure Summary.

1.4 Methodology

Refer to individual Basis of Preparation documents as relevant to the underlying Expenditure reported in templates, as drawn through to populate the Expenditure Summary.

Duplications- A matrix of Category Analysis RIN requirements was prepared which identified reporting of capex, opex, SCS, and ACS, direct, overheads, gifted asset exclusions, for each table. Further checks were identified where instructions or definitions in the RIN identified specific inclusions / exclusions for activities reported. Discussions were held with appropriate staff to understand how costs are treated within Ergon Energy's financial systems to identify duplications in various activities reported throughout the CA RIN. Duplicated amounts reported throughout tables were linked through into the reconciliation file identifying the associated activity and amount of the duplication.

Reconciliation between CA RIN and Regulatory Reporting Statements (Annual Reporting RIN) – Adopting the same process mentioned for duplications above, differences between the CA RIN and the **Annual Reporting RIN** were identified for Total Capex and Total Opex.

Reconciliation between Regulatory Reporting Statements (Annual Reporting RIN) & Audited Statutory Accounts – Based on the AER's Issue Register, where reconciliations had already been reported between Audited Statutory Accounts and the Distribution Network Service Provider (SCS, ACS) in the Regulatory Reporting Statements (RRS) these are also to be considered in meeting compliance with the CA RIN requirements.

Additional information was required to be extracted from the Ergon Energy Financial Information (within the Audited Statutory Accounts for Energy Queensland Limited) in respect of Capex as no such reconciliation is otherwise reported. Extracts of the Work in Progress additions from the Financial Statement Notes for Property, Plant and Equipment were used to compare to the Distribution Network Service Provider (DNSP) Capex figures reported in RRS. As the DNSP operates within the entity Ergon Energy Corporation Limited (Ergon Energy), which provides both regulated and non-regulated services, non-regulated capital expenditure is the largest driver of reconciling differences for all years. A further difference relates to the adjustments required under economic regulation, to capex for shared assets.

1.5 Assumptions

Refer to Section 1.6 Estimated or Actual Information which describes assumptions made.

1.6 Estimated or Actual Information

Where the underlying Expenditure reported in templates is noted as being actual information, the data in the Expenditure Summary Table also reflects actuals.

Where the underlying Expenditure reported in templates is noted as being estimated information, the data in the Expenditure Summary Table also reflects estimates. Note for 2018-19, Maintenance and Metering templates are made up of both actual and estimated information and are input into the templates as such. For Maintenance, Routine Maintenance is actual information while Non-Routine Maintenance is estimated information. For Metering, New Meter Installation and Other Metering are estimated information while the rest of the Metering template is actual information.

1.7 Explanatory Notes

Table 1-1 Explanatory Notes

RIN Reference	Requirement	Attachments
Appendix E, paragraph 2.4-2.5	• Ergon Energy must provide an Excel spread sheet that contains the calculation of balancing items reported in Regulatory Template 2.1 • Ergon Energy must provide reconciliation between the total capital and operating expenditure provided in the Regulatory Template 2.1 to the capital and operating expenditure recorded in Ergon Energy's Regulatory Accounting Statements. • Ergon Energy must provide reconciliation between the total capital and operating expenditure provided in Ergon Energy's Regulatory Accounting Statements to the capital and operating expenditure recorded in Ergon Energy's Audited Statutory Accounts.	• Attachment 1 ERG T2.1 Balancing Items 31 Oct 2019 • Attachment 2 ERG T2.1 Reconciling Items 31 Oct 2019 • Attachment 3 ERG T2.1 Reconciliation to Statutory Accounts 31 Oct 2019

2 BOP - 2.2 Repex (Actual)

2.1 Scope of BOP - Table 2.2.1 Expenditure and Volumes

2.1.1 Table 2.2.1 - Replacement Expenditure and Volumes

2.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

2.3 Sources

The key data sources used to produce figures for replacement expenditure and asset replacement volumes through SAP HANA solution using source project and General Ledger (GL) Transaction and Planning Approval Reports.

2.4 Methodology

The following approaches were applied to derive these values for replacement expenditure and replacement volumes against the Repex asset categories based on the current stage of the project:

Replacement Expenditure Process

Step 1 – Replacement project data extraction

- A report is run from the SAP Hana tool which includes all replacement projects that incurred expenditure in the 2018-19 regulatory year under the replacement financial activity codes detailed in Table below:

Table 2-1 Replacement Projects Activity Codes

Description	Typical Project Scope	Project Life Cycle
Line Distribution program (C2000 & C2020)	Lines Distribution replacement projects – Poles, cross arms, transformers, switches, overhead lines and underground cables	maximum 12 months

	(<=11kV).	
Substation program (C2020)	Sub-Transmission replacement projects –overhead lines and Underground Cables (=11kV).	12 months to max of 4-5 years

- SAP Hana tool – Modelled data repository captured data from data warehouse.

NOTE:

Currently the stock code mapping process applies only for line distribution program as the substation programs does not have stock codes at the moment. Therefore substation replacement volume and expenditure are manually calculated based on strategic scope of the project, planning approval reports, scope statement, project estimates and Ellipse asset specifics.

Step 2 - Stock code with Repex Asset Category code extraction

- Respective material transaction records are used to allocate expenditure to the Repex asset categories for all lines program projects that had expenditure in 2018-19.
- Stock code from Work orders - Every transaction happens under a work order which contains stock codes with Repex asset category and expenditure.

Step 3 (a) – Apportionment Methodology – Lines Program

- The apportionment process is explained with the following example *(for illustration purpose only, not real data).
- From the SAP Hana Transaction table, the following transactions were extracted for a Repex top project WR123456 Feeder ABC Replace Pole Mount Plant with assumed 2018-19 financial year expenditure.

Table 2-2 Repex Transaction Codes

Transaction No:	**Expense Element**	**Transaction Amount**	**Repex Asset Category**
67241280000	Labour	$50,000	Unknown
71872900000	Material	$79,000	Pole Mounted ; < = 22kV ; > 60 kVA and

			< = 600 kVA ; Single Phase
71872900001	Material	$25,000	< = 11 kV ; Switch
71872900002	Material	$10,000	Non AER material (e.g.; porcelain insulator)
27874220000	Contract	$10,000	Unknown
67241280000	Other	$31,981	Unknown
	Total	***$205,981***	

- As shown in Table above, material expenditure with Repex asset category will pass through directly to respective AER asset class. In the example, $79,000 will be allocated to AER asset class ‘TR Pole Mounted; < = 22kV; > 60 kVA and < = 600 kVA; Single Phase’ and $25,000 to “< = 11 kV; Switch “ in Repex Table 2.2 expenditure template.
- To allocate remaining unknown expenditure ($79,000 + $25,000 – $205,981 = $101,981), the materials expenditure for Repex asset category will be converted into weighted averages, based on the materials expenditure in each Repex asset category relative to the total Repex materials expenditure for the project.

Table 2-3 Repex Apportionment Percentage

Stock Code	**Repex Asset Category**	**Transaction Amount**	**% Apportionment =** **(Material Transaction amount) /** **(Total Material Transaction)**
SC69856	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	$79,000	75.96%

SC98647	< , = 11 kV ; Switch	$25,000	24.04%
Total cost of materials	Total	$104,000	100%

- Remaining unknown expenditure ($79,000 + $25,000 – $205,981 = $101,981) will be allocated to the respective Repex asset category based on weightings shown in Table below.

Table 2-4 Apportioned Repex Expenditure

Asset Category	**Apportionment**	**Repex Expenditure**
Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	= 75.96% x $ 101,981	$74,466
< , = 11 kV ; Switch	= 24.04% x $ 101,981	$24,515
Total	***100%***	***$101,981***

- Total Lines distribution expenditure apportioned using the above process is $211M and this is 85% of total Repex expenditure $249.6M.

<u>Step 3 (b) – Apportionment Methodology – Substation Program</u>

- Total substation expenditure is $37M and this 17% of total Repex expenditure $249.6M.

- As substation projects don't have stock codes information allocated to project, manual apportionment methodology is required for all substation program including SCADA communication programs as the project materials are allocated in the projects as expenditure without stock code information.

- Manual apportionment is undertaken in accordance with the same methodology outlined in Step 3 (a) for each work request based on the scope of work. In order to determine the expenditure values and asset volumes of Repex assets replaced as part replacement projects, a detailed review of replacement projects was undertaken. Specifically, this involved reviewing individual project files and engineering specifications to identify the assets, and associated costs of the assets, which would be replaced as part of the project.

- Using the replacement volume derived, to calculate the apportionment percentage, standard estimates are used. These standard estimates are maintained annually by Estimation department and cost of asset items are reviewed and updated by Standards team annually.
- The manually achieved replacement is believed to be the materially correct number as the subject matter experts review every project in detail with corporate project documents and Ellipse asset management tool.
- Manually apportioned information and volume is fed back into the SAP Hana tool to ensure that the reporting is governed and repeatable.

NOTE: As part of merger (Ergon Energy & Energex) initiative, EQL is working towards RIN process alignment and this is the main driver for change in methodology compare to previous years. EQL also working towards reviewing substation program to contain stock code information so that the automated lines program methodology can be used.

Replacement Volume Process

<u>Step 1</u> and <u>Step 2</u> are as same as illustrated in Replacement Expenditure process

<u>Step 3 (a)</u> – Replacement Volume – Lines Program

- The lifecycle of lines program projects are typically a maximum of one year
- Therefore if an asset is booked/transacted in the respective financial year, it is considered to be electrically commissioned on the same financial year.

<u>Step 3 (b)</u> – Replacement Volume – Substation Program

- The lifecycle of substation program projects are typically a minimum of one year to maximum of 4 to 5 years.
- The replacement volume is derived from corporate asset management system – Ellipse.
- In Ellipse, the asset attributes with commission and decommission always keep updated by Data team whenever a project completes construction phase and asset electrically commissioned or scrapped from network.
- First step is to manually looking of change of status in Ellipse for every asset compare to the previous financial year.
- From the asset list, manually validated the asset attributes to differentiate between Repex and Augex work using work request number.
- The validated Repex asset installed volume will be entered into respective RIN asset class.

The validated quantities are entered into REPEX template Table 2.2.1 accordingly.

2.5 Assumptions

- At present, Ergon Energy does not report replacement expenditure according to the asset categories listed in RIN Table 2.2.1. In order to satisfy the data requirements in RIN Table 2.2.1, Ergon Energy had to develop a methodology of allocating replacement expenditure to the Repex asset categories.
- For each project that was analysed as part of RIN Table 2.2.1, Ergon Energy has calculated a value of the respective financial year materials expenditure against each of the Repex asset categories. The materials expenditure for Repex asset categories has been converted into weighted averages, based on the materials expenditure in each Repex asset category relative to the total materials expenditure for the project. The weighted average values calculated for each Repex asset category was used as a basis for allocating total non-Repex material expenditure (labour, contract and others) to respective Repex asset categories in the Repex template.
- The public lighting asset information included in this template belongs to public lighting works happened under SCS Repex budget.
- Asset replacement volumes for Service Lines include apportionment of Services replaced under (C2000 and C2020). These quantities have been calculated using a 33m length for each service line quantity based on average span length.
- Overhead conductor and underground cable replacement volumes were provided as “km”.
- To achieve the actual replacement unit and expenditure apportionment, the methodology is to use ‘stock codes’ procured under each work request for distribution lines program.
- The comprehensive review of stock codes is carried out and all stock codes are manually mapped to an AER RIN asset category, thus allowing the current year methodology explained in following sections to take place.
- In the stock code mapping process, as one stock code can have only one AER asset code assigned to it, therefore following assumptions are made:
- Certain pole dimensions can be installed across following voltage levels LV, 11kV and 22kV, therefore actual pole installed usage rate across various voltage levels is used as to derive from Ellipse system the final replacement unit for wood poles. The calculated apportion rate used is 20%, 40% and 40% for LV, 11kV and 22kV respectively.

2.6 Estimated or Actual Information

Ergon Energy has provided actual Information, in accordance with the AER's definition, in relation to the following variables:

- Expenditure by Asset Category (2018-19)
- Asset Replacements (2018-19)

2.7 Explanatory Notes

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

- Where asset sub-categories corresponding to the prescribed asset categories were provided, the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category.
- Additional rows were inserted to provide a clear indication of the asset category applicable to each sub-category.
- The expenditure on refurbishment activities performed by Ergon Energy apart from pole staking are not material to the template and therefore not separately disclosed per the notice requirements.
- Additional rows have been inserted to account for assets not accounted for under the prescribed asset group categories or sub-categorisations.
- The sum of the individual asset categories, including any additional sub-category, additional other asset category or Asset Refurbishments / Life Extensions asset category expenditure reconciles to the total expenditure of the asset group.
- Ergon Energy has reported replacement volumes by asset group in Template 2.2, Table 2.2.1 that equal the applicable replacement volume data provided in table 2.2.2.
- The sum of the asset group replacement expenditures is equal to the total replacement expenditure contained in template 2.1 (Expenditure Summary)
- Activity Codes C2000 and C2020 from Ergon Energy's project Ledger have been used to identify expenditure on replacement expenditure projects. The project classification code J2 is used to differentiate between lines and substation program.

General issues

In distribution businesses it is very common for projects to span a number of years depending on the complexity of the project. However, the CA RIN requires expenditure to be reported on an as incurred basis. This definition leads to a disconnection between replacement expenditure and replacement volumes. For example, if a project spans five years the bulk of the expenditure may occur in the third year based on the purchase of major items, however the project may not be commissioned until the fifth year

Only projects with a primary replacement driver have been included in this analysis. As a result, assets replaced due to condition, as part of an augmentation driven project, were not included in this analysis

Unallocated Expenditure:

Ergon Energy identified expenditure in 2018-19 that could not be allocated to existing AER replacement categories. This expenditure is listed in the other (DNSP defined) at the bottom of the template as “Other non AER Asset Categories. The annual expenditure allocated to “Other Non AER Asset Categories” in the Repex model for the 2018-19 regulatory year was $5,494,255.

The unallocated expenditure consists of following categories:

- Defect remediation and return to service projects without AER asset class
- Weather response cyclone Debbie rectification project without AER asset class
- Asbestos related projects
- underground pillar covers,
- meters
- miscellaneous substation assets such as electrical equipment cabinets and lighting fixtures.

Reconciliation:

The difference between data from the project ledger and the general ledger is 0.64% ($1,588,935), mainly due to different methods in filtering out the Non SCS / Non System components. The Finance ‘AER Categories’ are associated to BPUs within Projects. There can be several BPUs within a Project which point to different AER Categories. However, the SAP Hana Project Ledger doesn’t go down to a level below Project level – so Project ‘J Code’ proxies are identified to try to approximate the BPU deductions – but they aren’t the same. The difference is applied to categories within the replacement costs proportionately to align to the general ledger.

2.8 Scope of BOP - Table 2.2.1 Asset Failures

2.8.1 Table 2.2.1 - Asset Failures by Asset Category

2.9 Compliance with CA RIN Requirements

Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.1: Replacement Expenditure Volumes and Asset Failures, by Asset Category, in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

2.10 Sources

The source of Actual Information was retrieved using the database application SAP HANA. The application was used to collate data from different source systems, which were:

- Outage Management System Application: FeederSTAT
- Enterprise Resource Planning (ERP) Application: Ellipse

2.11 Methodology

For the following Asset Groups, the following *Methodology A* was applied:

- Pole, Pole Top, Overhead Conductors, Underground Cables, Service Lines.

Methodology A:

The information was compiled utilising the network Unplanned and Forced Outages in conjunction with Maintenance Strategy Support System (MSSS Code) codes configured within ERP Ellipse work order fields.

Explanation of Difference in Asset Failure numbers between Past Year and Current Year:

Ergon Energy recognises that the asset failure numbers submitted for the Current Year (CY) is a considerable decrease compared to Past Years (PY). The reason for this is because Ergon Energy has attempted to comply with asset failure definition as per the AER requirement, where an asset failure should only be Unassisted Failure.

In PY’s submissions, Ergon Energy have included both Assisted and Unassisted Failures, and defect replacement into the submission. Therefore the asset failure counts were considerably much higher.

Explanation of Unplanned and Forced Outages:

The outages are limited to Unplanned and Forced Outages. Unplanned Outages means an unexpected interruption to the power supply caused by a fault on the network. Whereas a Forced Outage is a planned outage where Emergency Switching to carry out unplanned repairs or emergency maintenance of the Network is required.

Explanation of Ellipse Work Order and MSS configuration.

Within ERP Ellipse, a work order has dedicated fields to allow Asset Management to identify root cause of failure or root cause for performing the corrective work or root cause that an unplanned outage have occurred. These dedicated fields are described as Maintenance Strategy Support System (MSSS Codes), which consist of:

- Component Code / Component Modifier Code / Object / Damage / Cause / Consequence

Association between Outages Information and Ellipse Work Order:

For Ergon Energy, an Unplanned Outage or a Forced Outage are always associated with a work order creation in Ellipse. The work orders are created systematically when the outage occurs. And upon closure of work orders MSSS configuration are compiled by Distribution Services.

In compiling the asset failure numbers the following assumptions were made:

Ellipse work order's MSSS Codes attributes are deemed and assumed to be the root cause of failure.

Information entered into other respective fields such as with Ellipse's Work Order Description, Work Order Long Description and Work Order Completion Text or Outage Trigger and Outage Reason Description are utilised as support information which assists us with filtering out Assisted Failures.

Assisted Failures are assumed to be external impacts such as:

- Extreme or atypical weather events
- Third party interference, such as traffic accidents and vandalism
- Wildlife interference, but only where the wildlife interference directly, clearly and unambiguously influenced asset performance
- Vegetation interference, but only where the vegetation interference directly, clearly and unambiguously influenced asset performance

Where the work order has appropriate MSSS Codes that suggest that the asset has failed. It is assumed to be a single failure event.

Where the work order has appropriate MSSS Codes that suggest that the asset have failed, but without support information (e.g. Outage Trigger). Because the MSSS Codes suggests that the failure had occurred, such event is assumed to be a single failure event.

Where the work order has appropriate MSSS Codes that suggest that the asset has failed, but supporting information (e.g. Outage Trigger) suggests that the outage event was caused by external impact(s) that are deemed as Assisted Failures, such event(s) are excluded where possible.

For the following Asset Groups and its Asset Categories *Methodology B* was applied:

Switchgear:

- < = 11 kV ; Circuit Breaker
- 11 kV & < = 22 kV ; Circuit Breaker
- 22 kV & < = 33 kV ; Circuit Breaker
- 33 kV & < = 66 kV ; Circuit Breaker
- 66 kV & < = 132 kV ; Circuit Breaker
- 132 kV ; Circuit Breaker

Transformer:

- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA
- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; < = 15 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; < = 100 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; > 100 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 132 kV ; < = 100 MVA

- Ground Outdoor / Indoor Chamber Mounted; > 132 kV ; > 100 MVA
- Field Devices

Methodology B:

Asset Groups/Categories associated with Methodology B have been assumed to be Substation Assets.

A review of Ergon Energy's Return to Service (RTS) project was conducted with the respective regional Subject Matter Experts to identify project(s) associated with Asset Failures, where the asset could no longer be returned to service.

Where a review RTS projects were not possible due to staff resourcing and internal business restructure reasons. Interviews were conducted with the respective regional Workgroup Leaders, Crew leaders and Work Scheduler to identify the Asset Failures work conducted through the 2018-19 period.

Explanation of RTS Project:

RTS Projects are projects associated with asset replacement that are due to failures of an asset or deterioration of an asset where an asset replacement is required and was not planned as part of Capital Program.

2.12 Assumptions

Refer to Section 2.10 Methodology for assumptions applied.

2.13 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER's definition, in relation to Asset Failures (2018-19). For the following Asset Groups and Asset Categories:

- Pole, Pole Top, Overhead Conductors, Underground Cables, Service Lines
- Switchgear:
- < = 11 kV ; Circuit Breaker
- 11 kV & < = 22 kV ; Circuit Breaker
- 22 kV & < = 33 kV ; Circuit Breaker
- 33 kV & < = 66 kV ; Circuit Breaker
- 66 kV & < = 132 kV ; Circuit Breaker

- 132 kV ; Circuit Breaker
- Transformer:
- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA
- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; < = 15 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; < = 100 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; > 100 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 132 kV ; < = 100 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 132 kV ; > 100 MVA

Also refer to Section 3 BOP – 2.2 Repex (Estimate) for Asset Failures reported as estimated information.

2.14 Explanatory Notes

Not Applicable.

2.15 Scope of BOP - Table 2.2.2 Volumes in commission

2.15.1 Table 2.2.2 - Selected Asset Characteristics (Asset Volumes currently in commission)

2.16 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

Ergon Energy does not have "CBD" Poles, Conductor or Cable assets.

Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

2.17 Sources

Information has been sourced from the below systems:

- Smallworld, GIS
- Ellipse, ERP
- Outage Management System (OMS)

2.18 Methodology

Asset volume in commission by feeder type for poles, conductor and cable is sourced from Ergon Energy's Smallworld (GIS), Ellipse (ERP) and Outage Management System (OMS). GIS is used to determine the conductor lengths broken down by feeder and the material used for overhead Conductors. A combination of ERP and GIS is used to get a count of poles broken down by feeder. The feeder type for each feeder is determined from the classifications in OMS. This allows asset volumes to be determined by feeder type.

Ergon Energy's OMS has a feeder classification of Transmission. Assets associated with the Transmission classification were included in the asset volumes for "Rural Long".

Assets for which no classification could be determined were allocated to the feeder type in the same proportion as other assets associated with the feeder type.

2.19 Assumptions

Refer to Section 2.18 Methodology for assumptions applied.

2.20 Estimated or Actual Information

Ergon Energy has provided Actual Information.

- Currently in commission

2.21 Explanatory Notes

It should be noted that the total poles in table 2.2.2 does not include pole staking, because a pole stake is a reinforcement applied to support a pole and not a pole asset in and of itself.

2.22 Scope of BOP - Table 2.2.2 Replacement Transformers

Table 2.2.2 - Selected Asset Characteristics - Asset Replacements (Transformers)

2.23 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

2.24 Sources

Information has been sourced from the system:

- Smallworld, GIS
- Ellipse, ERP

2.25 Methodology

Transformer capacity in commission is sourced from Ergon Energy's Smallworld (GIS) and Ellipse (ERP). A combination of ERP and GIS is used to get a total sum of rating of transformers.

- For Zone transformers, MVA ratings have been sourced from Ergon Energy's corporate ERP – Ellipse (Asset Management Module) nameplate data.
- For Distribution Transformers, nameplate rating has been obtained from Ergon Energy's corporate ERP – Smallworld GIS data.

Ergon Energy provides the information of the TOTAL MVA in commission in each year in cell I171 to L171 where the column heading is "ASSET VOLUMES CURRENTLY IN COMMISSION" and the row heading is "Total MVA replaced".

- As the units are different, the value of the total physical unit of transformer replaced will not agree with the total value of transformer MVA replaced.

2.26 Assumptions

Refer to Section 2.25 Methodology above for assumptions applied.

2.27 Estimated or Actual Information

Ergon Energy has provided Actual Information in relation to the following variables:

- Total MVA currently in commission
- Ergon Energy has provided Estimated Information to the rest of the table.

Refer to Section 3.15 - 3.20 for Estimated Information reported for Table 2.2.2 Replacement Transformers.

2.28 Explanatory Notes

Not applicable.

3 BOP – 2.2 Repex (Estimate)

3.1 Scope of BOP - Table 2.2.1 Asset Failures

3.1.1 Table 2.2.1 - Asset Failures by Asset Category

3.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Table 2.2.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

3.3 Sources

Source of Estimated Information was retrieved using database application SAP HANA. The data was collated from the source system:

- Enterprise Resource Planning (ERP) Application: Ellipse

3.4 Methodology

Methodology C:

Asset Group/Categories associated with *Methodology C* have been assumed to be Distribution Network Assets and Communication Equipment. This differs to Asset Group/Categories associated with *Methodology B* where it was assumed to be Substation Assets.

For Asset Group/Categories associated with this methodology, the estimated stock unit usage associated with RTS projects were assumed to be asset failure counts.

The estimated stock unit usage was estimated by:

Extract RTS project for 2018-19, then review the RTS project material costing with respective Asset RIN Categories:

1. Extract the Stock issued quantity and the respective Asset RIN Categories.
2. Calculated the average unit cost for the respective Asset RIN categories.
3. Divide the #1 against #2 to derive the Stock Usage Unit per RTS Project.
4. Add the total quantity for the respective Asset RIN Categories.

With the exception for Communication Network Equipment, Communication Site Infrastructure and Communication Linear Assets. The estimated asset failure counts were Estimated by counting the RTS failure work orders associated with equipment replacement and then grouped into the relevant Asset Categories.

3.5 Assumptions

Refer to Section 3.4 Methodology for assumptions applied.

3.6 Estimated or Actual Information

Ergon Energy has provided Estimated Information, in accordance with the AER’s definition, in relation to Asset Failures (2018-19). For the following Asset Groups and Asset Categories:

Public Lighting, Communication Network Equipment, Communication Site Infrastructure, Communication Linear Assets.

- Transformer:
    - Pole Mounted ; < = 22kV ; < = 60 kVA ; Single Phase
    - Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase
    - Pole Mounted ; < = 22kV ; > 600 kVA ; Single Phase
    - Pole Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase
    - Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase
    - Pole Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase
    - Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Single Phase
    - Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase
    - Kiosk Mounted ; < = 22kV ; > 600 kVA ; Single Phase
    - Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase
    - Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase
    - Kiosk Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase
    - Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Single Phase
    - Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Single Phase
    - Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Single Phase

- Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Multiple Phase
- Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Multiple Phase
- Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Multiple Phase

- Switchgear:
  - < = 11 kV ; FUSE
  - < = 11 kV ; Switch
  - 11 kV & < = 22 kV ; Switch
  - 22 kV & < = 33 kV ; Switch
  - 33 kV & < = 66 kV ; Switch
  - 66 kV & < = 132 kV ; Switch
  - 132 kV ; Switch

3.7 Explanatory Notes

It was not possible to use Actual Information, and Estimate is required because the corporate application and the associated processes were not envisioned or configured with the level of detail requested by the AER.

Due to the large quantity of RTS Project associated with the respective Asset Group and Asset Categories and corporate application do not allow Ergon Energy to clearly identify Unassisted Failures, Assisted Failure or Defect replacement projects, the best estimate approach was taken.

3.8 Scope of BOP - Table 2.2.2 Replacements

3.8.1 Table 2.2.2 - Selected Asset Characteristics - Asset Replacements for Poles, Overhead Conductors and Underground Cables

3.9 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

Ergon Energy does not have "CBD" Poles, Conductor or Cable assets.

Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

3.10 Sources

Information has been sourced from:

- Smallworld, GIS
- Ellipse, ERP
- Outage Management System (OMS)

3.11 Methodology

In relation to Replacements, Ergon Energy has developed an estimate based on an approach whereby the ratio of Urban, Rural and Rural Long asset volumes and material type is used to assign a portion of the replacements to each category.

3.12 Assumptions

Refer to Section 3.11 Methodology for assumptions applied.

3.13 Estimated or Actual Information

Ergon Energy has provided Estimated Information in relation to the following variables:

- Replacements

3.14 Explanatory Notes

It is not possible to use Actual Information and an estimate is required in relation to Asset Replacements because the assets do not have these categories attached.

3.15 Scope of BOP - Table 2.2.2 Replacement Transformers

Table 2.2.2 - Selected Asset Characteristics - Asset Replacements (Transformers)

3.16 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the Notice.

Ergon Energy has prepared the information provided in Template 2.2, Table 2.2.2 in accordance with the Notice requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the Notice.

3.17 Sources

Information has been sourced from the system:

- Ellipse, ERP

3.18 Methodology

TOTAL MVA DISPOSED OF

TOTAL MVA REPLACED

TOTAL MVA [replaced in current year]

In relation to TOTAL MVA, Ergon Energy has developed an estimate based on the following approach

- For Substation transformers, MVA ratings have been sourced from Ergon Energy's corporate ERP-Ellipse. The nameplate data is summated.
- For Distribution Transformers, nameplate rating has been obtained stores issues data. The nameplate rating is contained within the text description of distribution transformers in the inventory register. A temporary data table was produced by reading each distribution transformer description and giving it a rating.
- Total MVA capacity replaced each year is then obtained by adding Power transformer data to Distribution transformer data

In developing this estimate, Ergon Energy assumed those transformers that are installed are booked to the correct code.

Ergon Energy considers this the best estimate has been provided for these TOTAL MVA as the inventory system is well maintained and has rigorous processes and the manual searching was vigorous.

3.19 Assumptions

Refer to Section 3.18 Methodology section above for assumptions applied.

3.20 Estimated or Actual Information

Ergon Energy has provided Estimated Information in relation to the following variables:

- TOTAL MVA DISPOSED OF
- TOTAL MVA REPLACED
- TOTAL MVA [replaced in current year]

3.21 Explanatory Notes

It was not possible to use Actual Information. An estimate is required in relation to TOTAL MVA DISPOSED OF, because there is a large time lapse when transformers are sent to be tested for possible repair and then are disposed.

It was not possible to use Actual Information. And an estimate is required in relation to TOTAL MVA REPLACED, because there is no direct record in our system of when an asset is replaced, or log of when it is replaced.

Also refer to Section 2 BOP - 2.2 Repex (Actual) for the transformers currently in commission reported as Actual Information.

4 BOP - 2.3 Augex

4.1 Scope of BOP

4.1.1 Table 2.3.1 - Augex Asset Data - Subtransmission Substations, Switching Stations and Zone Substations

4.1.2 Table 2.3.2 - Augex Asset Data - Subtransmission Lines

4.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.3(a), Table 2.3.1 and Table 2.3.2 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Ergon Energy have considered and complied with clarifications provided by the AER on issues related to template 2.3(a) and relevant to Ergon Energy.

Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported), excluding costs relating to non-network assets identified as part of the annual reporting RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type.

Ergon Energy has not included information for gifted assets, and no augmentation expenditure in relation to connections has been included in template 2.3(a).

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

Projects were included for augmentation and the addition of equipment within sub-transmission substations i.e. monitoring and communication equipment under Table 2.3.1, although there were no additional capacity (MVA) added to substations. These projects were therefore included as non-material projects.

Unless otherwise indicated, 'Rating' or ‘MVA added’ refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). The calculations of capacity are based on normal conditions and in response to paragraph 7.1(b), Ergon Energy defines “normal conditions”:

“When assessing compliance with the network security criteria it is important to select the correct plant ratings for each scenario. It should be noted that, the Normal Cyclic Capacity (NCC) of equipment applies during system normal conditions i.e. where all network elements are in service.” NCC Values given for Transformers have been taken from SIFT (Substation Investment Forecast Tool)

With regards to Related Party expenditure:

- As a consequence of the Queensland Energy Consolidation on 30 June 2016, Energex and Ergon Energy have become related parties and will be required to make associated related party disclosures for RIN reporting purposes.
- Within the Ergon Energy group, the parent entity Ergon Energy Corporation Limited (EECL) maintains controlling interest over three reporting entities. These include Ergon Energy Queensland Pty Limited (EEQ) and Ergon Energy Telecommunications Pty Limited (EET) which are both 100% owned, and a jointly controlled entity SPARQ Solutions Pty Ltd (SPARQ) where Ergon Energy maintains a 50% ownership interest. EEQ is a non-competing electricity retailer; EET is a wholesale telecommunication service provider; and SPARQ is an information, communications and technology service provider.
- Ergon Energy did not identify any Related Parties contract expenditure in relation to Augmentation (capital) expenditure (Augex) projects and Related Party Margins is recorded as “zero”.
- All Non Related Party Contracts are calculated as the Total Contractors expenditure. Expenditure in ‘All related party contracts’ and ‘All non-related party contracts’ columns do not contribute to the total direct expenditure on an augex project (‘Total direct expenditure’) as required.
- Finally, all contract expenditure for augex projects under the ‘All related party contracts’ and ‘All non-related party contracts’ columns were allocated to the appropriate ‘Plant and equipment” expenditure and “Other Expenditure”.

Ergon Energy has considered and complied with clarifications provided by the AER on issues related to template 2.3(a) and relevant to Ergon Energy.

With regards to instructions specific to Table 2.3.1 (on regulatory template 2.3(a)), Ergon Energy notes:

- Ergon Energy has reported all expenditure data for augex in Table 2.3.1 in real $2018-19. Nominal dollars has been converted to real dollars using actual CPI rates (Dec-Dec for the weighted average of eight capital cities as published by the Australian Bureau of Statistics

(ABS). Calculations have been provided as **Attachment 4 ERG T2.3 Augex (Nominal to Real) 31 Oct 2019.**

- Ergon Energy only included data in Table 2.3.1 for augmentation works where project close occurred within the year specified and did not include data for works where the project closed after the year specified but incurred expenditure prior to this date.
- Augex projects on a subtransmission substation, switching station and zone substation owned and operated by Ergon Energy with greater than or equal to $5 million (nominal) cumulative expenditure over the life of the project where project close occurred at any time in the year specified, have been reported separately in Table 2.3.1.
- In this regard, both direct and indirect (overheads) costs were included in determining the cumulative expenditure over the life of a project as per the AER clarification however, only the direct cost was reportable in Table 2.3.1.
- Projects with less than $5 million nominal expenditure over the life of the project where project close occurred at any time in the year specified have been consolidated into the expenditure figures in the penultimate row of Table 2.3.1.
- All augmentation work on substations in Ergon Energy's network was included in Table 2.3.1. There were no substations operating at notional transmission voltages.
- Each row in Table 2.3.1 represents an individual substation and project. Ergon Energy does not conduct work on more than one substation per one project. Ergon Energy uses a parent project with child projects underneath the parent project to structure projects. The highest level (parent project) is the substation with all the components relevant to that one substation raised as child projects under the parent project.
- No substation augex projects in Table 2.3.1 are related to other projects, including other tables in template 2.3(a).
- The substation ID's provided in Table 2.3.1 represents Ergon Ellipse Asset substation identification number and the work request ID is Ergon Energy's project number allocated within the Ellipse operating system.
- The primary trigger was selected within the drop down list provided. None of the projects listed in Table 2.3.1 have any secondary triggers to be disclosed. Ergon Energy has provided additional information in relation to projects where "Other – specify" were selected in Template 2.3 Table 2.3.1 Other – specify.

- Voltages on substations listed in Table 2.3.1 were entered in the format xx/xx or xx/xx/xx, reflecting the primary, secondary and tertiary voltages.

- Ergon Energy has complied with the required in put ‘Pre’ and ‘Post’ substation ratings as per paragraph 7.2 (k)

- Ergon Energy only included procurement cost under ‘Total expenditure’ for transformers, switchgear, capacitors and other plant items. Installation costs have been reported separately in each table.

With regards to Land and Easement expenditure:

- Total direct expenditure does not include any expenditure for land or easements.

- Furthermore, Ergon Energy input all expenditure directly attributable to the land purchase or easement compensation payments in the ‘Land purchases’ and ‘Easements’ columns, respectively, including legal, stamp duties and cost of purchase or easement compensation payments. Where contractor payments were not coded to the Land & Easement expense element the costs were included under “Installation Labour” or “Other Plant”.

- Ergon Energy calculated ‘Other Plant’ expenditure as the total cost of all equipment and materials booked to the relevant project less actual cost for Transformers, Switchgear and Capacitors.

Table 2.3.2 - Augex Asset Data - Subtransmission Lines

Unless otherwise indicated, 'Rating' or ‘MVA added’ refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). The calculations of capacity are based on normal conditions and in response to paragraph 7.1(b), Ergon Energy defines “normal conditions”:

“When assessing compliance with the network security criteria it is important to select the correct plant ratings for each scenario. It should be noted that, the Normal Cyclic Capacity (NCC) of equipment applies during system normal conditions i.e. where all network elements are in service.”

With regards to instructions specific to Table 2.3.2 (on regulatory template 2.3(a)), Ergon Energy notes:

- Ergon Energy has reported all expenditure data for augex in Table 2.3.2 in real $2018-19. Nominal dollars has been converted to real dollars using actual CPI rates (Dec-Dec) for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS). Calculations have been provided as **Attachment 4 ERG T2.3 Augex (Nominal to Real) 31 Oct 2019.**

- Ergon Energy only included data in Table 2.3.2 for augmentation works where project close occurred within the year specified and did not include data for works where the project closed after the year specified but incurred expenditure prior to this date.
- Augex projects on a subtransmission line owned and operated by Ergon Energy with greater than or equal to $5 million (nominal) cumulative expenditure over the life of the project where project close occurred at any time in the year specified to report separately in Table 2.3.2.
- In this regard both direct and indirect (overheads) cost was included in determining the cumulative expenditure over the life of a project as per AER clarification. Only direct cost was included in Table 2.3.2.No subtransmission lines augmentation projects in Table 2.3.2 are related to other projects, including other tables in template 2.3(a).

With regards to Land and Easements:

- Total direct expenditure does not include any expenditure for land purchases or easements.
- Ergon Energy did not record any land and easement projects and/or expenditure as separate line items in Table 2.3.2.
- Ergon Energy input all expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively, including legal, stamp duties and cost of purchase or easement compensation payments.

4.3 Sources

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

Actual Information for the financial variables was sourced from Ergon Energy's Ellipse operating system.

The following actual information for non-financial variables was sourced from "as built" schematics and relevant planning reports:

- Transformers – Units added
- Transformers – MVA Added
- Switchgear – Units added
- Capacitors – MVAR added
- Substation Rating Normal Cyclic (MVA)

- Substation Rating N-1 Emergency (MVA)

Table 2.3.2 - Augex Asset Data - Subtransmission Lines

Actual Information for the financial variables was sourced from Ergon Energy's Ellipse operating system

Note: no 2.3.2 Material Projects were identified this RIN Period.

4.4 Methodology

TABLE 2.3.1 - AUGEX ASSET DATA- SUBTRANSMISSION SUBSTATIONS, SWITCHING STATIONS AND ZONE SUBSTATION

Report was run from the Ellipse operating system which listed all projects closed within regulatory year under the augex financial activity codes C2010, C2030, C2040 and C2050 – the MASTER_C2010_C2030_C2040_C2050 report, excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type.

The Report included all Ergon Energy augex projects, not only those related to Subtransmission Substations, Switching Stations and Zone Substations. The project list was filtered to include only those projects relating to Subtransmission Substations, Switching Stations and Zone Substations by analysing the project j-codes (asset classification codes) and extracting Subtransmission Substations, Switching Stations and Zone Substations projects.

The extracted substation project list reported each project and their total cumulative expenditure over the life of the project, broken down by direct costs and overheads as well as their total annual expenditure as incurred (excluding overheads). Each project with a total (whole of life) expenditure of equal or greater than $5 million (nominal, inclusive of direct and overhead costs) was reported as a separate project in the RIN template. Those projects less than $5 million were labelled as a non-material project to be consolidated into a single substation line item in Table 2.3.1.

The report also provided cost per project for the following expenditure categories: Materials, Contractor cost, Labour cost, Purchases, Stores, Other direct cost.

Further detailed expenditure reports were run from Ellipse on each material project providing details of each expense booked to the project.

In order to report the information in the required expense categories per Table 2.3.1, Ergon Energy applied the following methodology and assumptions to the data presented in the MASTER_C2010_C2030_C2040_C2050 report:

Installation (Labour) Volume was calculated as the sum of Total Labour Hours reported within Ellipse Fin 900h reports for each project.

Installation (Labour) Expenditure was calculated as the Sum of Contractors and Labour as per the MASTER_C2010_C2030_C2040_C2050 report, less civil works labour identified through detailed analysis of labour expenditure for each project.

Civil Works Expenditure was calculated on the Asset apportionment percentage for Substation Buildings on the Incurred To Date Costs (excluding overheads). There is no report available to provide this information as civil costs fall to the contractor expense elements.

After reviewing detailed contractor and purchase transactions for Projects in Ellipse reports we could not identify with accuracy civil works costs. We therefore used the BPU apportionment for Substation buildings (percentage of project cost allocated to Substation buildings) and applied this percentage to the Total cumulative costs (excluding overheads) of the individual projects and input as civil works cost into Table 2.3.1.

- **Transformer Expenditure** was identified and calculated by reviewing individual project transaction reports (Ellipse Fin 900h reports) and identifying and totaling individual transactions under expense categories for “purchases and material’ that related to transformers

- **Switchgear Expenditure** was identified and calculated by reviewing individual project transaction reports (Ellipse Fin 900h reports) and identifying and totaling individual transactions under expense categories for “purchases and material’ that related to switchgear

- **Capacitor Expenditure** was identified and calculated by reviewing individual project transaction reports (Ellipse Fin 900h reports) and identifying and totaling individual transactions under expense categories for “purchases’ that related to capacitors. No capacitor expenditure was identified

Other Plant Expenditure was calculated as the Total Materials and Purchases as per the MASTER_C2010_C2030_C2040_C2050 report, less actual cost for Transformers, Switchgear and Capacitors.

Other Direct Expenditure was calculated as the Total Other Costs as per the MASTER_C2010_C2030_C2040_C2050 report, less the sum of Land and Easements.

Total Other Cost as per MASTER_C2010_C2030_C2040_C2050 report includes Land and Easement cost. Other Costs also includes:-

- Computer

- Marketing

- Other
- Transport Internal
- Transport External
- Travel & Accommodation

Years Incurred was sourced from the MASTER_C2010_C2030_C2040_C2050 report. Projects reported in regulatory year are based on closure dates within this regulatory period, some projects will have incurred final costs in previous financial years.

Related Party Margins is recorded as "zero"; Ergon Energy did not identify any Related Parties contract expenditure in relation to Augmentation projects.

All Non Related Party Contracts is disclosed as the Total Contractors expenditure as per the MASTER_C2010_C2030_C2040_C2050 report

Land Purchase and Easements cost is included as Other Costs in the MASTER_C2010_C2030_C2040_C2050 report. Land and Easement cost was therefore calculated by running an Ellipse report for activities C2010, C2030, C2040 & C2050 by expense element 6160 (Easement/Land), the MASTER_Augex Account Codes_WO Txns with EE 6160 report. This report provided the total land and easement cost per project. To split the cost between Land Purchase and Easements, we used the BPU apportionment for Land (L5) (percentage of project cost allocated to Land) and Easements (L9) (percentage of project cost allocated to Easement) from MASTER BPU Data report and applied this percentage to the total Land and Easement expenditure as per MASTER_Augex Account Codes_WO Txns with EE 6160 report for each project and input as Land purchase or Easements in Table 2.3.1.

Non Material Projects – Total Direct Expenditure was sourced from the MASTER_C2010_C2030_C2040_C2050 report. The total cumulative expenditure (excluding overheads) over the life of the projects identified as non- material projects as per the MASTER_C2010_C2030_C2040_C2050 report was listed as Total Direct Expenditure for Non Material projects in Table 2.3.1.

Non Material Projects – Years Incurred was sourced from the MASTER_C2010_C2030_C2040_C2050 report

Non Material Projects - Land Purchase and Easements was calculated by applying the same methodology as for Land Purchase and Easements for material projects described above.

Non-financial Variables The following actual information for non-financial variables was sourced from "as built" schematics and relevant planning reports:

- Transformers – Units added
- Transformers – MVA Added
- Switchgear – units added
- Capacitors – MVAR added
- Substation Rating Normal Cyclic (MVA)
- Substation Rating N-1 Emergency (MVA)

Converting nominal to real values

Ergon Energy has reported all expenditure data for augex in Table 2.3.1 in real $2018-19. Nominal dollars has been converted to real dollars using actual CPI rates (Dec-Dec) for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS).

The MASTER_C2010_C2030_C2040_C2050 report provided a split of total cumulative cost (excluding overheads) in nominal values for each year in which cost was incurred. Ergon Energy applied the relevant CPI rate for each specified year in which cost was incurred to convert the nominal values to real values.

The following assumptions were applied in converting nominal values to real values:

- **Land & Easements** - The financial year in which land and easements costs were incurred was not specified within reporting data. The assumption that land and easement costs have been incurred first was applied to convert land and easement cost to real values.
- **Expenditure categories -** Cost incurred by financial year cannot be split by expense category. Total project cost nominal values per year incurred have therefore been converted to real values and total real values apportioned into expenditure categories based on the nominal values allocated to each expense category.

Table 2.3.2 - Augex Asset Data - Subtransmission Lines

Report was run from the Ellipse operating system which listed all projects closed within regulatory year under the Augex financial activity codes C2010, C2030, C2040 and C2050 – the MASTER_C2010_C2030_C2040_C2050 report, excluding costs relating to non-network assets identified as part of the annual performance RIN preparation. To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type.

The report included all Ergon Energy augex projects, not only those related to Subtransmission lines. The project list was filtered to include only those projects relating to Subtransmission lines by analysing the project j-codes (asset classification codes) and extracting Subtransmission line projects.

The extracted line project list reported each project and their total cumulative expenditure over the life of the project, broken down by direct costs and overheads as well as their total annual expenditure as incurred (excluding overheads). Those projects less than $5 million were labelled as a non-material project to be consolidated into a single subtransmission line item in Table 2.3.2.

The report also provides cost per project for the following expenditure categories: Materials, Contractor cost, Labour cost, Purchases, Stores, Other direct cost.

Note: no 2.3.2 Material Projects were identified this RIN Period requiring submission of the following data.

Non Material Projects – Total Direct Expenditure was sourced from the MASTER_C2010_C2030_C2040_C2050 report. The total cumulative expenditure (excluding overheads) over the life of the projects identified as non- material projects as per the MASTER_C2010_C2030_C2040_C2050 report was listed as Total Direct Expenditure for Non Material projects in Table 2.3.2.

Non Material Projects – Years Incurred was sourced from the MASTER_C2010_C2030_C2040_C2050 report. Projects reported in regulatory year are based on closure dates within this regulatory period, some projects will have incurred final costs in previous financial years.

Non Material Projects - **Land Purchase and Easements** cost is included as Other Costs in the MASTER_C2010_C2030_C2040_C2050 report. Land and Easement cost was therefore calculated by running an Ellipse report for activities C2010,C2030,C2040 & C2050 by expense element 6160 (Easement/Land), the MASTER_Augex Account Codes_WO Txns with EE 6160 report. This report provided the total land and easement cost per project.

To split the cost between Land Purchase and Easements, we used the BPU apportionment for Land (L5) (percentage of project cost allocated to Land) and Easements (L9) (percentage of project cost allocated to Easement) from MASTER BPU Data report and applied this percentage to the total Land and Easement expenditure as per MASTER_Augex Account Codes_WO Txns with EE 6160 report for each project and input as Land purchase or Easements in Table 2.3.2.

Note: no 2.3.2 Material Projects were identified this RIN Period

Converting nominal to real values

Ergon Energy has reported all expenditure data for augex in Table 2.3.2 in real $ 2018-19. Nominal dollars has been converted to real dollars using actual CPI rates (Dec-Dec for the weighted average of eight capital cities as published by the Australian Bureau of Statistics (ABS).

The MASTER_C2010_C2030_C2040_C2050 report provided a split of total cumulative cost (excluding overheads) in nominal values for each year in which cost was incurred. Ergon Energy applied the relevant CPI rate for each specified year in which cost was incurred to convert the nominal values to real values.

The following assumptions were applied in converting nominal values to real values:

Land & Easements – The financial year in which land and easements costs were incurred was not specified within reporting data. The assumption that land and easement costs have been incurred first was applied to convert land and easement cost to real values.

Expenditure categories - Cost incurred by financial year cannot be split by expense category. Total project cost nominal values per year incurred have therefore been converted to real values and total real values apportioned into expenditure categories based on the nominal values allocated to each expense category

4.5 Assumptions

Refer to Section 4.4 Methodology for assumptions applied.

4.6 Estimated or Actual Information

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

Ergon Energy has provided Actual Information, in accordance with the AER's definition, for the following variables in Template 2.3(a), Table 2.3.1 which requires expenditure data on a project close basis, for all initial regulatory years

- Installation Volume
- Installation (Labour) Expenditure
- Civil Works Expenditure
- Other Direct Expenditure
- Years Incurred

- All Non Related Party Contracts
- Land Purchase
- Easements
- Non Material Projects – Total Direct Expenditure
- Non Material Projects – Years Incurred
- Non Material Projects – Land Purchase
- Non Material Projects – Easements
- Voltage (KV)
- Substation Rating Normal Cyclic (MVA)
- Substation Rating N-1 Emergency (MVA)
- Transformers – Units added
- Transformers – MVA Added
- Transformers – Expenditure
- Switchgear – units added
- Switchgear – Expenditure
- Capacitors – MVAR added
- Capacitors – Expenditure

The majority of Augmentation projects incurred cost over more than one financial year and in some cases over a number of financial years.

Projects with project close dates within the reporting period would have had cost incurred in prior reporting periods, which was included in expenditure disclosed in Table 2.3.1.

Projects were included in Table 2.3.1 only where the project close date occurred at any time in the year specified. Project close date (i.e. project finalisation date) is when all project costs have been recognised and reconciled, and not the date at which the project was put in service and capitalised. The project close date could differ from the project capitalisation date.

Table 2.3.2 - Augex Asset Data - Subtransmission Lines

Ergon Energy has provided Actual Information, in accordance with the AER's definition, for the following variables in Template 2.3(a), Table 2.3.2 which requires expenditure data on a project close basis, for all initial regulatory years

Note: no 2.3.2 Material Projects were identified this RIN Period

- Non Material Projects – Total Direct Expenditure
- Non Material Projects – Years Incurred
- Non Material Projects – Land Purchase
- Non Material Projects – Easements

The majority of augex projects incurred cost over more than one financial year and in some cases over a number of financial years.

Projects with project close dates within the reporting period would have had cost incurred in prior reporting periods, which was included in expenditure disclosed in Table 2.3.2.

Projects were included in Table 2.3.2 only where the project close date occurred at any time in the year specified. Project close date (i.e. project finalisation date) is when all project costs have been recognised and reconciled, and not the date at which the project was put in service and capitalised. The project close date could differ from the project capitalisation date.

4.7 Explanatory Notes

Not applicable.

5 BOP - 2.3 Augex B

5.1 Scope of BOP

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

5.1.2 Table 2.3.3.1 Descriptor Metrics

5.1.3 Table 2.3.3.2 Cost Metrics

5.1.4 Table 2.3.4 - Augex Data - Total Expenditure

5.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.3(b) - Augex project data, Table 2.3.3 - Descriptor Metrics (units upgraded; added in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Ergon Energy has only included projects and expenditure related to augmentation of the network (only projects under augmentation financial activity codes C2010, C2030, C2040 and C2050 have been reported), excluding costs relating to non-network assets identified as part of the annual reporting RIN preparation. To exclude non-network costs, the value of the non-network assets at the project level was deducted from the reported RIN period expenditure, after the total value had been initially recorded for reconciliation purposes. Ergon Energy has not included information for gifted assets, and no augmentation in relation to connections has been included in template 2.3(b). However, the value includes the cost of installing Distribution Transformers and HV & LV reticulation assets associated with Street Lighting applications (Capital Activity C2120)

Ergon Energy have considered and complied with clarifications provided by the AER on issues related to template 2.3(b) and relevant to Ergon Energy.

Table 2.3.3.1 - Descriptor Metrics

With regards to instructions specific to Table 2.3.3 (on regulatory template 2.3(b)), Ergon Energy notes:

- Metrics relating to augmentation works on the specified types (overhead lines, underground cables) of ***HV feeders*** owned and operated by Ergon Energy undertaken at any time during the year specified have been reported, regardless of total spend.

- Metrics relating to augmentation works on the specified types (overhead lines, underground cables) of ***LV feeders*** owned and operated by Ergon Energy undertaken at any time during the year specified have been reported, regardless of total spend.

- Metrics relating to augmentation works on the specified types (pole mounted, ground mounted, indoor) of ***Distribution Substations*** owned and operated by Ergon Energy undertaken at any time during the year have been reported.

- For projects spanning across regulatory years, *'circuit km added'*, *'circuit km upgraded'* and 'Units" (Descriptor Metric) data was input according to the total expenditure incurred across all financial periods, only for projects that were completed in the reported RIN financial year.

Table 2.3.3.2 - Cost Metrics (Expenditure)

With regards to instructions specific to Table 2.3.3 (on regulatory template 2.3(b)), Ergon Energy notes:

- Expenditure on augmentation works on the specified types (overhead lines, underground cables) of ***HV feeders*** owned and operated by Ergon Energy undertaken at any time during the year specified for projects with a cumulative or estimated expenditure over the life of the project greater than or equal to $0.5 million (nominal), have been reported. Works on HV Feeders for projects with less than $0.5 million nominal expenditure over the life of the project have been consolidated into the Non-material projects row of the table.

- Expenditure on augmentation works on the specified types (overhead lines, underground cables) of ***LV feeders*** owned and operated by Ergon Energy undertaken at any time during the year specified for projects with a cumulative or estimated expenditure over the life of the project greater than or equal to $50,000 (nominal), have been reported. Works on LV Feeders for projects with less than $50,000 nominal expenditure over the life of the project have been consolidated into the Non-Material Projects row of the table.

- Expenditure on augmentation works on the specified types (pole mounted, ground mounted, indoor) of ***Distribution Substations*** owned and operated by Ergon Energy undertaken at any time during the years have been reported.

- Projects were included for augmentation and the addition of equipment on HV Feeders, LV Feeders and Distribution substations i.e. monitoring and communication equipment under Table 2.3.3 Cost Metrics, even though there were no additional HV Feeders, LV Feeders and distributions substations units added (circuit length kms). Expenditure has been recorded on an 'as incurred' basis in nominal dollars'

- Expenditure related to land purchases and easements is not included in the 'Total Direct Expenditure' column. Land purchases and easements expenditure related to augmentation works on all ***HV feeders, LV Feeders*** or ***Distribution Substations*** owned and operated by Ergon Energy are input in Table 2.3.3.

Table 2.3.4 - Augex Asset Data - Total Expenditure

Total augmentation expenditure has been input for each asset group split by the groupings specified by the table.

Expenditure has been recorded on an 'as incurred' basis in nominal dollars'.

Expenditure inputted under the 'land and easements' rows are mutually exclusive from expenditure that appears in the rows for the corresponding asset group.

In regards to requirements in paragraph 7.7(b) Ergon Energy provides the following explanation in relation to reconciling the expenditure in Table 2.3.4 to the sum of the asset group augmentation expenditures in Table 2.3.1 (Subtransmission substations, switching stations, zone substations) and Table 2.3.2 (Subtransmission Lines) and Table 2.3.3 (HV/LV Feeders and Distribution Substations):

- The data sources for information disclosed in tables 2.3.1, 2.3.2, 2.3.3 Cost Metrics and 2.3.4 are identical, being the MASTER_C2010_C2030_C2040_C2050 report from the Ellipse operating system. The base data used for all tables will therefore reconcile, However, due to the inconsistencies in the basis of preparation and disclosure requirements, the following will apply to tables 2.3.1 and 2.3.2:

- Projects listed in Table 2.3.1 and Table 2.3.2 are disclosed on a project closed basis and projects included in Table 2.3.4 are disclosed on a cost incurred basis.

- Ergon Energy has reported all expenditure data for augex in Table 2.3.1 and Table 2.3.2 in real $2018-19 as required by the Principles and Requirements in the Category Analysis RIN and expenditure data for Table 2.3.4 in nominal dollars.

- The majority of augex projects listed in Table 2.3.1 and Table 2.3.2 incurred cost over more than one financial year and in some cases over a number of financial years.

- Projects with close dates within the reporting period and disclosed in Table 2.3.1 and Table 2.3.2 would have had cost incurred before the reporting period . This cost incurred before the reported period is not reported in Table 2.3.4 expenditures, as the cost did not incur within the reporting period.

- Opposite to this, projects and the associated cost may have been reported in Table 2.3.4 in the year it incurred, but not reported in Tables 2.3.1 and 2.3.2 given the projects were not finalised and closed within the reporting years.
- Expenditure reported in Table 2.3.3 Cost Metrics reconciles to expenditure disclosed in Table 2.3.4 for HV Feeders, LV Feeders, Distribution Substations, HV Feeders – Land purchases and Easements, LV Feeders – Land purchases and Easements and Distribution Substations – Land purchases and Easements, as the basis of preparation and data sources are identical.

5.3 Sources

Table 2.3.3.1 - Descriptor Metrics

Ergon Energy notes the source of Actual Information for the following variables:

- Distribution Substation Augmentations, both Units Added & Units Upgraded, was sourced from CA_Augex_RIN_Requisition _Data report with introduced Distribution and Project Status Categories ;
    - Distribution Category New or Upgraded
    - Project Status Open or Closed
    - Augex 2.3.3 Metric Class, quantifying the reporting category under which each Stock Item is recorded
- Raw conductor and cable acquisition (by metre) was sourced from CA_Augex_RIN_Requisition _Data report.

Table 2.3.3.2 - Cost Metrics (Expenditure) and Table 2.3.4 - Augex Asset Data - Total Expenditure

Actual information for total expenditure was sourced from MASTER_C2010_C2030_C2040_ C2050 report, an extract from the Ellipse financial database of all Capital Works expenditure by cost category & financial year which was funded through Activities C2010, C2030, C2040 and C2050 (Augmentation).

5.4 Methodology

Table 2.3.3.1 - Descriptor Metrics

In order to obtain the information, it was necessary for Ergon Energy to apply additional data qualifiers to the MASTER_C2010_C2030_C2040_C2050 report to allow identification of each parcel of works by Distribution categories in accordance with the requirements of Table 2.3.3

In doing so, it was assumed that:

- All Projects with Project Category (J2) Codes of either Subs-Sub-Transmission, Subs-Transmission, Lines-Sub-Transmission & Lines Transmission were outside the requirements of Table 2.3.3 and were eliminated from the reporting set.
- All projects where the primary Equipment Reference No had a 'GS' suffix, indicating a Generation Site, were eliminated from the reporting set, after verifying the scopes of a random selection of projects.
- Distribution Categories were identified from the reporting suite through the use of Project Category (J2) Codes Lines Distribution, Lines SWER, Subs Distribution and Subs SWER.
- Distribution Categories were validated through the use of Project Category (J3) Codes Overhead New, Upgrade or Replace; Underground New, Upgrade or Replace; Transformers New, Upgrade or Replace; Regulators New, Upgrade or Replace; SWER Isolators New, Upgrade or Replace; Steel Conductor New, Upgrade or Replace; Copper Conductor New, Upgrade or Replace; Services New, Upgrade or Replace
- Distribution Categories were validated through the use of Equipment Reference characteristics, such as:
- Equip ID Prefix SP = Substation Pole Mounted
- Equip ID Prefix GT = Ground Mounted Network Slot
- Equip ID Prefix AB = HV Isolating Device Network Slot
- Distribution Categories were validated through the use of Works Request Description Identifiers, such as:
    - Reference to HV or HV Voltages (11, 22 & 33kV)
    - Reference to SWER or SWER Voltages (12.7 & 19.1kV)
    - Reference to LV or LV Voltages (0.240 & 0.415kV)
    - Reference to ABC Installation (Arial Bunched Cable)
    - Reference to UG or UG Assets (Padmount, RMU etc.)
- Following the application of Distribution categories through the above process, any uncategorised projects were categorised through a review of the individual scope of works within the Works Request data.

- Actual information for Land Purchase and Easements was sourced from MASTER_Augex Account Codes_WO Txns with EE 6160 Report. Reported RIN Period Data from the above report was imported into the 2.3.3_Master_Final Worksheet summary and the Land Acquisition transactions associated solely with Work Requests classified as 2.3.3 identified. As expected, Distribution assets, which are in the majority installed on Crown land, strung beneath sub-transmission assets on existing infrastructure in existing corridors or installed with the authority of the landholder by execution of a Wayleave, returned nominal values for land & easements either acquired or capitalised.

- Disparity of unit cost rate arises due to the following factors:

- Units added/upgraded are based on the actual life to date costs of closed qualifying projectsof material acquisition extracted from the MASTER RIN Reporting Requisitioning Data Report, whereas installation costs are on an as incurred basis and costs have in some cases material acquisition has occurred in a financial period prior to the current reporting period.

- Ergon Energy supply area covers 97% of the state of Queensland and as such, experiences geographical cost factors associated with the supply, transport & storage of materials at significant distance from logistic bases as well as an equally significant travel component for both internal & contract labour resources

- The process of determining feeder circuit length for Distribution works based on the actual length of conductor can be impacted by Ergon Energy's material ordering process, whereby all conductor is issued from Material Services by full drum only. Subsequent unused portions of conductor are returned for credit on completion of the project. For projects where the initial conductor requisition occurs in one financial year and the return of surplus in the following financial year the circuit length calculation is overstated in the year of issue and equally understated in the year of return.

- During the reported RIN period Ergon Energy also undertook a number of Distribution projects which added no circuit length to the Distribution network and the associated expenditure is reported in the "Other Assets" data of Table 2.3.4

Table 2.3.3.2 - Cost Metrics (Expenditure)

In order to obtain the information, it was necessary for Ergon Energy to apply additional data qualifiers to the MASTER_C2010_C2030_C2040_C2050 report to allow identification of each parcel of works by Distribution categories in accordance with the requirements of Table 2.3.3

In doing so, it was assumed that:

- All Projects with Project Category (J2) Codes of either Subs-Sub-Transmission, Subs-Transmission, Lines-Sub-Transmission & Lines Transmission were outside the requirements of Table 2.3.3 and were eliminated from the reporting set.

- All projects where the primary Equipment Reference No had a 'GS' suffix, indicating a Generation Site, were eliminated from the reporting set, after verifying the scopes of a random selection of projects.

- Distribution Categories were identified from the reporting suite through the use of Project Category (J2) Codes Lines Distribution, Lines SWER, Subs Distribution and Subs SWER.

- Distribution Categories were further identified through the use of Project Category (J3) Codes Overhead New, Upgrade or Replace; Underground New, Upgrade or Replace; Transformers New, Upgrade or Replace; Regulators New, Upgrade or Replace; SWER Isolators New, Upgrade or Replace; Steel Conductor New, Upgrade or Replace; Copper Conductor New, Upgrade or Replace; Services New, Upgrade or Replace

- Distribution Categories were further identified through the use of Equipment Reference characteristics, such as:

Equip ID Prefix SP = Substation Pole Mounted

Equip ID Prefix GT = Ground Mounted Network Slot

Equip ID Prefix AB = HV Isolating Device Network Slot

- Distribution Categories were further identified through the use of Works Request Description Identifiers, such as:
  - Reference to HV or HV Voltages (11, 22 & 33kV)
  - Reference to SWER or SWER Voltages (12.7 & 19.1kV)
  - Reference to LV or LV Voltages (0.240 & 0.415kV)
  - Reference to ABC Installation (Arial Bunched Cable)
  - Reference to UG or UG Assets (Padmount, RMU etc.)

- Following the application of Distribution categories via the above process, any uncategorised projects were determined through a review of the individual scope of works within the Works Request data.

- Actual information for Land Purchase and Easements was sourced from MASTER_Augex Account Codes_WO Txns with EE 6160 Report. Reported RIN Period Data from the above report was imported into the 2.3.3_Master_Final Worksheet summary and the Land Acquisition transactions associated solely with Work Requests classified as 2.3.3 identified. As expected, Distribution assets, which are in the majority installed on Crown land, strung beneath sub-transmission assets on existing infrastructure in existing corridors or installed with the authority of the landholder by execution of a Wayleave, returned nominal values for land & easements either acquired or capitalised.

- Disparity of unit cost rate arises due to the following factors:

    - Units added/upgraded are based on the actual life to date costs of closed qualifying projects of material acquisition extracted from the MASTER RIN Reporting Requisitioning Data Report, whereas installation costs are on an as incurred basis and costs have in some cases rolled over to the following financial period.

    - Ergon Energy supply area covers 97% of the state of Queensland and as such, experiences geographical cost factors associated with the supply, transport & storage of materials at significant distance from logistic bases as well as an equally significant travel component for both internal & contract labour resources

    - The process of determining feeder circuit length for Distribution works based on the actual length of conductor can be impacted by Ergon Energy's material ordering process, whereby all conductor is issued from Material Services by full drum only. Subsequent unused portions of conductor are returned for credit on completion of the project. For projects where the initial conductor requisition occurs in one financial year and the return of surplus in the following financial year the circuit length calculation is overstated in the year of issue and equally understated in the year of return.

    - During this reported RIN period Ergon Energy also undertook a number of Distribution projects which added no circuit length to the Distribution network and the associated expenditure is reported in the "Other Assets" data of Table 2.3.4

Table 2.3.4 - Augex Asset Data - Total Expenditure

Data disclosed in Table 2.3.4 was sourced from the MASTER_C2010_C2030_C2040_C2050 report and reported as appearing on the reports without making any assumptions or adjustments to the data.

HV Feeders – Land purchases and Easements, LV Feeders – Land purchases and Easements and Distribution Substations – Land purchases and Easements are reported at nominal values.

Distribution assets are, in the main, placed within the road reserve and as such do not require land or easement acquisitions. Where distribution assets cross private property Ergon Energy takes Wayleave Agreements from the property owners, which are binding on subsequent owners, giving Ergon Energy the right to access and maintain the distribution assets without the need to acquire land.

Projects under activity codes C2010, C2030, C2040 and C2050 that relates to augmentation, excluding costs relating to non-network assets identified as part of the annual performance RIN preparation, but could not be classified under the specified asset categories of subtransmission substations, switching stations, zone substations, subtransmission Lines, HV/LV feeders and distribution substations was disclosed as “other assets” in Table 2.3.4.

To exclude non-network costs, the proportion of total non-network assets to network assets based on actual ellipse data was used to estimate the non-network costs for each project type.

5.5 Assumptions

Refer to Section 5.4 Methodology for assumptions applied.

5.6 Estimated or Actual Information

Ergon Energy has used Actual Information, in accordance with the AER’s definition, for the following variables in Table 2.3.3 Descriptor Metrics:

- HV Feeder Augmentations – Overhead lines (circuit line length KM) added and upgraded.
- HV Feeder Augmentations – Underground cables (circuit line length KM) added and upgraded.
- LV Feeder Augmentations – Overhead lines (circuit line length KM) added and upgraded
- LV Feeder Augmentations – Underground cables (circuit line length KM) added and upgraded
- Distribution Substation Augmentations – Pole Mounted - Units Added & Units Upgraded;
- Distribution Substation Augmentations – Ground Mounted - Units Added & Units Upgraded;
- Distribution Substation Augmentations – Indoor - Units Added & Units Upgraded.

Of note in 2018-19, Overhead & Underground line lengths were deemed to be actuals this year based on:

- Improved level of granularity in the SS10 codes which categorises conductor & cable at the inventory level
- Our methodology & inventory data is now virtually identical to the Energex submission, which also reports all CA RIN data as actual

5.7 Explanatory Notes

Table 5-1 Explanatory Notes

RIN Reference	Requirement	Attachments
7.2(c)(i), and 7.3(c)(i)	Where expenditure has been reported in real \$2018-19, provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.	Attachment 4 ERG T2.3 Augex (Nominal to Real) 31 Oct 2019.

6 BOP - 2.5 Connections

6.1 Scope of BOP

6.1.1 Table 2.5.1 Descriptor Metrics

6.1.2 Table 2.5.2 Cost Metrics by Connection Classification

6.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.5, Table 2.5.1 and Table 2.5.2 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Table 2.5.1 - Descriptor Metrics

As advised by the AER, Ergon Energy has not had regard to paragraph 9.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN.

In completing the template, Ergon Energy has not distinguished expenditure between Standard and Alternative Control Services (ACS). Similarly, Ergon Energy has not distinguished between capex or opex. Furthermore, costs have been measured as the direct cost, excluding overheads.

This is in accordance with clauses 9.2 and 9.3 of the RIN Appendix E Principles and Requirements for Template 2.5.

Ergon Energy has reported expenditure data as a gross amount, that is to say, customer contributions have not been subtracted from expenditure.

Data has not been reported in relation to gifted assets, or connection services which have been classified as contestable by the AER. Rather, information relates only to non-contestable, regulated connection services, including works performed by third parties on behalf of Ergon Energy. This does not include:

- Contestable customers which included work undertaken by third parties engaged by customers;
- Net costs on jobs that had received a gift (the costs for these jobs excludes the value of the gift); and

- Negotiated connection services

For augmentation metrics, the ‘km added’ reported refers to the net addition of circuit line length resulting from augmentation work of complex connections. The definition for complex connections has been referred to in this regard, and for other metrics as relevant.

Only augmentation for connections relating to customer connection requests (as per the defined term for connection expenditure) has been reported in Template 2.5. That is, no double counting in reporting of augmentation expenditure has occurred between Template 2.5 (Connections) and Template 2.3 (Augex).

MVA added for distribution substations installed for connection services is a view of Smallworld (GIS System) data. It is the MVA associated with the transformers added to the Network for that design.

Data which has been reported for Residential Customer connections relates to connecting customers who purchase energy principally for personal, household or domestic use at their premises. For completeness Ergon Energy has included rural customers within the scope of this definition.

Unless explicitly stated as not being provided fields with no value entered should be considered as having no expenditure or units in the relevant year.

Table 2.5.2 - Cost Metrics By Connection Classification (Volumes And Expenditure)

In completing the template, Ergon Energy has not distinguished expenditure between Standard Control Services or ACS. Similarly, Ergon Energy has not distinguished between capex or opex. Furthermore, costs have been measured as the direct cost, excluding overheads.

Ergon Energy has reported expenditure data as a gross amount, that is to say, customer contributions have not been subtracted from expenditure.

Data has not been reported in relation to gifted assets, or connection services which have been classified as contestable by the AER. Data relates only to non-contestable, regulated connection services, including works performed by third parties on behalf of Ergon Energy.

Ergon Energy does not have negotiated services; therefore no metrics are included in this regard.

The definition for complex connections has been referred to in relation to cost and descriptor metrics as relevant.

Only augmentation for connections relating to customer connection requests (as per the defined term for connection expenditure) has been reported in Template 2.5. That is, no double counting in reporting of augmentation expenditure has occurred between Template 2.5 (Connections) and Template 2.3 (Augex).

Data which has been reported for Residential Customer connections relates to connecting customers who purchase energy principally for personal, household or domestic use at their premises. For completeness Ergon Energy has included rural customers within the scope of this definition.

6.3 Sources

The PEACE Customer Information System (CIS) was used to provide:

- Underground and Overhead Connections
- Mean Days to Connect Customers (Residential)

The Smallworld Geographical Information System (GIS) was used to provide:

- Distribution Substation installed – MVA added
- Distribution substations installed – quantity
- Augmentation HV – net circuit km added
- Augmentation LV – net circuit km added

The Ellipse Enterprise Resource Planning (ERP) system was used to provide:

- Augmentation HV – total spend $0's
- Augmentation LV – total spend $0's
- Distribution substation installed – total spend 0's
- Overhead lots
- Underground lots
- Cost per lot ($)

Cherwell was used to provide:

- GSL Breaches (Residential)
- GSL Payments (Residential)
- Customer Complaints (Residential)

6.4 Methodology

Table 2.5.1 - Descriptor Metrics

In order to obtain the information, Ergon Energy applied the following methodology:

Customer requests for customer projects including subdivision development, connection or modification to existing connections are recorded within the Ellipse and PEACE systems. PEACE holds details related to physical premise connection and/or modification, whilst Ellipse stores both subdivision and customer project details related to provision of a "point of supply".

This initial data set (from both Ellipse and PEACE) assists with identification of a complete set of individual connection events active within the designated period. This provides the basis for extracting the associated attributes from other source systems to categories each connection event as required.

A SQL script was constructed and used to extract the data from PEACE as there were new 'Additions and Alteration' and 'New Connection' classifications added in the 2018-19 FY which were not used in the 2017-18 FY.

Customer complaint data relating to residential connections was sourced directly from Cherwell via the Enterprise Data Warehouse database. A similar query is also used to extract the Guaranteed Service Level data.

System Attributes & Categorisation

PEACE records data in categories with associated classes/subclasses that define the nature of the connection. Costs are either capitalised or expensed depending on the class/subclass type.

The classes/subclasses listed below form the basis of the data extracted/reported as follows

- New Connections (NC & SSWNC) - Capitalised
- Permanent Large NMI (PL)
- Permanent Small NMI (PM)
- Temporary Permanent Large NMI (IL)
- Temporary Permanent Small NMI (IP)
- New Connections (NC) - Expensed
- Temporary Large NMI (TL)
- Temporary Small NMI (TM)

- Adds and Alterations (AA) - Expensed
- Install Controlled Load (CL)
- Install Hot Water (HW)
- Service Upgrade (SU)
- Solar PV (PV)
- AA Dispatch (IM)
- Basic AA Connect (AA)

Unmetered Supplies (UM) are additionally extracted but are excluded from template 2.5 in line with the requirements described in the Regulatory Information RIN.

Each connection event is associated with a National Metering Identifier (NMI) which records categorisation details as follows:

- Commerical or Domestic
- Underground or Overhead
- Phases
- Low or High Voltage connection

Where phase data is missing from the NMI we have sourced this data from the “Form2’ data submitted by the customer/contractor where this is available.

Solar PV connections are logged as “Adds and Alterations” (AA/MSW) with a subclass of “’Solar PV” (PV) as defined above. This subset of events (AA PV) are used to both identify and provide data for the Embedded Generation category.

Generically Ergon Energy connects customers to the distribution network based on a request from a Retailer. This request is stored in a Service Order within PEACE that is associated with the contractor’s/customer’s request for connection or alteration. The Service Order records the logged date of the Retailer’s request and the logged completion date. The Service Order additionally identifies the Work Order (in the Ellipse ERP system) that was used to record the costs with completing the connection.

Connection counts (which exclude unmetered supplies as per the definition of a commercial/industrial customer connection) are determined for those events that were completed within the designated period.

The completion duration of the connection is calculated as the difference between the Obligation Start Date to Completion date

The population of the template item – “mean days to connect residential customer with LV single phase connection” – is achieved by identifying the connection events that satisfy the constraints required; specifically as residential, single phase and LV connection; and calculating the average duration.

Customer projects related to the modification to, or establishment of a point of supply, are recorded within Ellipse with each project assigned a unique Work Request number. Ergon Energy utilises two business models for customer projects which involve making offers to customers and agreeing commercial terms prior to undertaking the works required.

- Smaller low risk projects are managed by the Southern and Northern Connections Teams within Connection Solutions.
- Large complex projects are managed by the Major Customers Team within Connections Solutions.

Projects are selected for inclusion in the template on the basis that they satisfy one or more of the following:

- Have incurred cost during 2018-19
- Are associated with a physical premise connection request (PEACE EVENT)
- Are associated with Smallworld data that has been added to the network during the designated period
- The supply available date for Subdivision projects falls within the designated period

For Southern and Northern Connections projects referential information is associated with each work request which allows determination of:

- The project category as either residential, commercial/industrial, subdivision or embedded generation
- The number of lots (overhead or underground) for subdivision projects
- The date the customer accepted the offer
- The date the supply was made available.

Counts of subdivision lots were determined by identifying the subdivision projects and counting lots when supply was made available during the designated period. The average cost per lot was determined by dividing Ergon Energy's total costs incurred in the delivery of gifted and non-gifted subdivisions (upstream, reticulation development and test and commissioning) by the lots identified as having supply made available during the designated period.

As clarified by the AER (email dated 05/09/2017) we have excluded gifted asset costs but included gifted asset volumes as part of this calculation.. As such this methodology commenced from 2016/17 yet not for prior years.

Projects managed by the Major Customers Team do not store referential data within Ellipse. The following data has been manually loaded to the template after review of each project's data and other information held in the PC based system 'Salesforce' by the Major Customers Team:

- Project category – commercial/industrial, embedded generation etc
- Template 2.5.2 project categorization
- Date offer accepted
- Supply available date

Kilometres of cable, transformer counts and MVA added are sourced from the Smallworld GIS computer system using the project's work request to associate data. Smallworld data is included when the energisation date or completed date falls within the designated period.

Financial data related to HV, LV and Transformers is directly sourced from the General Ledger module of the Ellipse computer system by extracting transactions whose posting date falls within the designated period. Costs are associated by using either the work request or work order associated with the particular connection event under consideration.

Transactional costs are converted to the RIN requirements by using the methodology used within Ergon Energy to capitalise projects. Each project is assigned a number of Property Unit codes and percentages. These codes have been mapped to the RIN categories of HV, LV or Transformer allowing calculation of the respective values.

Embedded Generation Connections

Since the implementation of Power of Choice the volume of regulated service orders for Solar PV (PV) has reduced significantly, as this work is now contestable if a meter needs to be replaced. To ensure we provide accurate volumes of solar connections to the Ergon Energy Network a change in methodology was implemented.

When a customer connects solar, both a Connection Agreement and an Electrical Work request are received by Ergon Energy. Once these are received our source system PEACE is updated with the details of when the system was connected and the size of the system. This allows a query to be run to extract all solar connections that occurred within the 18/19 Financial Year along with their supply type. This figure was used to populate the Embedded Generation Underground and Overhead connection volumes.

Non-Financial Metrics – Residential GSL Breaches, Customer Complaints

The number of residential complaints relating to the connection or alteration of a connection service has been sourced from Cherwell via the Enterprise Data Warehouse. Complaints in Cherwell are categorised into their root cause issue, this has then been used to provide the volume of complaints. Complaints used were categorised as either "Supply - New Service/Extension" or "Major Customer Connection".

GSL Payments

Volume of GSL breaches is a count of approved "Connection of Supply" GSL claims recorded in the GSL Report application.

Collation of quarterly reports for financial year

2. Cross checked with a yearly report

3. Exclusions of GSLs not categorised as the following:

- New Connection
- Total volumes of GSL breaches are established by summing the total volume of the New Connection GSLs paid for each financial year, with a NMI Tariff Classification of Residential
- GSL payments are established by summing the total financial amount of New Connection GSLs paid for each financial year, with a NMI Tariff Classification of Residential

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

Each connection event identified to provide the financial and non-financial data for Table 2.5.1 has been assigned a categorisation attribute consistent with the sub categories specified for Table 2.5.2.

The assignment of this category is based on the application of the following rules:

For Peace and Connections Team records

Residential

- If the event has any capital HV costs and/or Transformer costs or Smallworld HV cable additions and/or Smallworld Transfomer additions related to a point of supply it is assigned to "Complex Connection HV"

- If the event only has capital LV costs or Smallworld LV cable for related to a point of supply it is assigned to "Complex Connection LV"
- If the event only relates to a final premise connection it is assigned to "Simple Connection LV"

Embedded Generation

- If the event has a Connections Team capital cost (LV, HV or Transformer) or Smallworld (LV, HV or Transformer) additions related to a point of supply it is assigned to - "Complex Connection HV (Small Capacity)"
- If the event only relates to a final premise connection it is assigned to - "Simple Connection LV"

Note: we have determined that anything more complicated won't exist as a Connections Team project but will be identified as Major Customers.

Commercial/Industrial

- If the event has Smallworld Transmission additions it is assigned to - "Complex Connection Sub-transmission"
- If the NMI associated with the event is identified as a HV connection the event is assigned to - "Complex Connection HV (customer connected at HV)"
- If the event has HV and transformer (capital costs and/or Smallworld additions) and number of transformers added is > 1 related to the point of supply it is assigned to - "Complex connection HV (customer connected at LV, upstream asset works)"
- If the event has s a capital HV cost or Smallworld HV cable addition related to the point of supply it is assigned to - "Complex connection HV (customer connected at LV, minor HV works)"
- If the event does not have a capital HV cost or Smallworld HV cable addition related to the point of supply or only relates to a final premise connection it is assigned to - "Simple Connection LV"
- Plus for Connections Team projects only

Subdivision

- If the project is being delivered under Ergon Energy's Developer Design and Construct (DDAC) model and there are capital HV or transformer costs and/or Smallworld HV cable additions or Transformer additions they must relate to the provisioning the point of supply and relate to upstream works. It is assigned to - "Complex connection HV (with upstream asset works)"

- If the project is not being delivered under Ergon Energy's Developer Design and Construct (DDAC) model and there are capital HV or transformer costs and/or Smallworld HV cable additions or Transformer additions consequently we cannot determine if these relate to upstream works or the subdivision itself. In this case the event is identified for manual "Review"
- If the event has no capital HV or transformer costs and/or Smallworld HV cable additions or Transformer additions it is assigned to – "Complex Connection LV"

Where the outcome of the assignment is "Review" the identified records have been manually reviewed by stakeholders and the 2.5.2 category manually assigned and loaded to the template.

Major Customer projects

Projects managed by the Major Customer Team do not store referential data within Ellipse. The template 2.5.2 project categorisation has been assigned and manually loaded to the template after review of each project's data and other information by the MCG.

Volume Data

Volume data is determined by counting the connection events within each category as defined by the above methodology. It should be noted that the volumes reported will not reconcile to the connection counts reported in template 2.5.1 owing to

- The 2.5.1 connection counts reflecting premise connection events that have completed within the designated period being reported whereas
- The volumes reported include all events regardless of the completion status of connections and additionally includes the counts of projects related to point of supply provisions, modifications and other connection events that contribute financially to the both the 2.5.1 and 2.5.2 templates.

6.5 Assumptions

Refer to section 6.4 Methodology for assumptions applied.

6.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, by extracting information directly from Ergon Energy's information systems, in accordance with the AER's definition, to develop the following required variables in Table 2.5.1 for 2018-19, for both financial and non-financial information:

- Underground and Overhead Connections
- Distribution Substation installed – MVA added
- Distribution substations installed – quantity

- Augmentation HV – net circuit km added
- Augmentation HV – total spend $0’s
- Augmentation LV – net circuit km added
- Augmentation LV – total spend $0’s
- Distribution substation installed – total spend 0’s
- Mean Days to Connect Customers (Residential)
- Overhead lots
- Underground lots
- Cost per lot ($)
- GSL Breaches (Residential)
- Customer Complaints (Residential)
- GSL Payments (Residential)

Ergon Energy has provided Actual Information, by extracting information directly from Ergon Energy’s computer systems, in accordance with the AER’s definition, for all variables in Table 2.5.2 for both financial and non-financial:

- Residential Simple connection LV ($0 & 0's)
- Residential Complex connection LV ($0 & 0’s)
- Residential Complex connection HV ($0 & 0’s)
- Commercial/Industrial Simple connection LV ($0 & 0's)
- Commercial/Industrial Complex connection HV (customer connected at LV, minor HV works) ($0 & 0's)
- Commercial/Industrial complex connection HV (customer connected at LV, upstream asset works) ($0 & 0's)
- Commercial/Industrial Complex connection HV (customer Connected at HV) ($0 & 0’s)
- Commercial/Industrial Complex connection sub-transmission ($0 & 0’s)
- Subdivision Complex connection LV ($0 & 0’s)
- Subdivision Complex connection HV (no upstream asset works) ($0 & 0's)
- Subdivision Complex connection HV (with upstream asset works) ($0 & 0's)
- Embedded generation Simple connection LV ($0 & 0’s)
- Embedded generation Complex connection HV (Small Capacity) ($0 & 0’s)
- Embedded generation Complex connection HV (Large Capacity) ($0 & 0’s)

6.7 Explanatory Notes

Not applicable.

7 BOP - 2.6 Non Network

7.1 Scope of BOP

7.1.1 Table 2.6.1 - Non-Network Expenditure

7.1.2 Table 2.6.2 - Annual Descriptor Metrics - IT & Communications Expenditure

7.1.3 Table 2.6.3 - Annual Descriptor Metrics - Motor Vehicles

7.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.6, Table 2.6.1, Table 2.6.2 and Table 2.6.3, in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Table 2.6.1 - Non-Network Expenditure

In completing Table 2.6.1 – Non-Network Expenditure, Ergon Energy notes that:

- Ergon Energy has reported Non Network expenditure in relation to standard control services (SCS) only.
- Ergon Energy has inserted additional *"asset categories"* under the *"service subcategory"* to represent office furniture and equipment, plant and equipment, crane borer plant HCV, Refurbishment/Rebuilt EWP(HCV) and other fleet assets. These *"asset categories"* were added as they have incurred $1 million or more (nominal) in capital expenditure (capex) in the regulatory year;
- Ergon Energy has included the replacement, installation, operation and maintenance of non-network buildings, fittings and fixtures in non-network buildings and property expenditure. This includes expenditure related to real chattels;
- Ergon Energy has included expenditure related personal chattels (e.g. furniture) under Non-network Office Furniture & Equipment.
- Ergon Energy has included in non-network IT and communication expenditure, costs associated with:
    - SCADA and Network Control that exist at the Corporate office side of gateway devices;

    - IT & Communications related to management, dispatching and coordination, etc. of network work crews;
    - Common costs shared between the SCADA and Network Control Expenditure and IT & Communications Expenditure categories with no dominant driver related to either of these expenditure categories; and
    - Network metering recording and storage at non network sites.

- Ergon Energy has reported all expenditure directly attributable to Motor Vehicles including: purchase, replacement, operation and maintenance of motor vehicles assets registered for use on public roads, excluding plant and equipment. Depreciation has been excluded as it does not meet the definition of Operating Expenditure (opex).

- During 2018/19 Ergon Energy reported a negative non-recurrent expenditure amount due to a Network Initiated Capitals Works project in relation to Communications not proceeding.

- Ergon Energy has included all expenditure directly attributable to the replacement, installation, maintenance and operation of Non-network assets in non-network other expenditure. This includes:
    - non road registered motor vehicles; non road motor vehicles;
    - mobile plant and equipment; tools; trailers (road registered or not);
    - elevating work platforms not permanently mounted on motor vehicles; and
    - Small Trailer Mounted Mobile Generators (Excludes Trailer Mounted Network Generators and Mobile Substations)

Table 2.6.2 - Annual Descriptor Metrics- IT & Communications Expenditure

In completing Table 2.6.2 – Non-Network Expenditure, Ergon Energy notes that it has:

- applied a simple average to determine the result where there were different values over the year;
- calculated user numbers based on active user accounts;
- calculated total client devices including hand held devices;
- scaled employee numbers, user numbers and number of devices in order to represent SCS metrics only.

Table 2.6.3 - Annual Descriptor Metrics - Motor Vehicles

In completing Table 2.6.3 – Non-Network Expenditure, Ergon Energy notes that:

- Data has been scaled to ensure reporting relative to SCS only; KMs is an average across the fleet so the application of the SCS does not impact the outcomes in this respect.
- Ergon Energy has applied a simple average to determine the result where there were different values over the year.

7.3 Sources

Table 2.6.1 - Non-Network Expenditure

Actual Information for the variables was sourced from Ergon Energy's ERP – Ellipse.

Table 2.6.2 - Annual Descriptor Metrics- IT & Communications Expenditure

Actual Information was sourced from:

- Annual stakeholder reports of Ergon Energy for Employee numbers.
- Software compliance reports For User numbers;
- Microsoft Active Directory report for User numbers; and
- System Centre Configuration Manager (SCCM) (Auto discover) and Active Directory for Number of devices.

An SCS percentage was applied to underling data extracted. This was sourced from SCS% sourced from Template 2.11 Labour workings (refer Basis of Preparation for Template 2.11).

TABLE 2.6.3 - ANNUAL DESCRIPTOR METRICS - MOTOR VEHICLES

Actual Information for the variables was sourced:

- KM travelled is sourced from a third party provider, which takes the odometer readings when fuel is purchased and provides the Annual KM's at Fleet Held at YE
- Number of assets (by category) commissioned into service and, number in fleet (by category) is recorded in the Ellipse Equipment Register and reported in the Fleet Asset Management Annual Review Document.
- Number in fleet includes assets with status of In Service, Out of Service, spares, Under repair and Temporary.

7.4 Methodology

Table 2.6.1 - Non-Network Expenditure

Data was sourced from Ergon Energy's ERP – Ellipse via an Expenditure Report which requests several inputs: Responsibility Centre/s (RC), Activity Code/s, and Period of inquiry. The RC and Activity is based on Ergon Energy's Chart of Accounts from which actual expenditure is reported against.

The output is itemised lines of expenditure data listed against an account code and where administered as such, the work order number and respective details are given (equipment ID, work category, workgroup etc.).

The Capex and Opex figures have been determined as follows.

<u>Building and Property</u>

Capex:

The BPU transaction report is used to report Non-Network Property capex in the regulatory accounts. This report is sourced from the Ellipse Project Ledger and is provided by the External Reporting team.

The SCS % is applied to each of the AER categories for Property Capex. Buildings, Land & Easements, and Land Improvements (Non-System) are summed and reported together.

Office Equipment & Furniture is reported separately under the 'Service Subcategory' section.

The Buildings and Property Capex numbers in Table 2.6.1 of the RIN are the cumulative sum of the twelve months for the regulatory (financial) year.

Opex:

It was assumed that all Buildings and Property Opex is recorded against the Property Services current responsibility centres and Activities 63900, 63910, 63920, 63930 and 62500 as detailed in the Chart of Accounts through running the OMD Expenditure Report.

- RC1250 is named Planning, Strategy and Performance and is a support function for the RC's 1260 (Property Services – Facilities) and RC1300 (Property Asset Management). Activities 63900-63930 are described as Property Services (Maintenance & Non-maintenance), while 62500 is Business Support Services and relates to the support related functions for the delivery of direct services.
- Data is filtered to exclude Expense Elements 5000 – Capitalisation, and Expense Element 8100 – Business Overheads.

There are some (minimal) expenditure line items which are listed with the above RC and activities and are reported against a network or fleet related asset. These items were identified by the Equip Reference field. These assets are not non-network property assets, but Opex has been spent against them in the context of Property based expenditure (or on-charged). These items remain in the data and are reported as part of this expenditure. In the context of the overall expenditure, they account for less than 0.5%.

There remains expenditure reported that is considered not directly attributable to an asset (i.e. building). This includes costs which support the people who deliver the services to the assets and general administration costs. These costs are predominately listed under activity 62500.

Finally, an SCS percentage was applied to the costs to meet requirements of the RIN. The relevant percentage is that calculated for the reporting of overheads, leaving the cost applicable to Standard Control.

The Buildings and Property Opex data reported in Table 2.6.1 represents a cumulative sum of the twelve months for the regulatory (financial) year.

IT and Communications

Data was sourced from Ergon Energy's ERP – Ellipse.

Client devices capex was extracted from the direct purchase Work in Progress codes which were analysed to identify client device expenditure. No operating costs were recorded against client devices.

Client Devices Expenditure is expenditure related to a hardware device that accesses services made available by a server and includes hardware involved in providing desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones, tablets and laptops.

Recurrent opex is extracted from a specific code (Responsibility Centre 0385) established within the Ellipse general ledger. This represents a total cost to Ergon Energy, including Ergon Energy Queensland (Retail) and Ergon Energy Telecommunications (EET) and is subsequently reduced by the relevant percentage to represent the ICT cost applicable to Ergon Energy Standard Control Services.

Recurrent capex is unable to be extracted directly from a report. Rather it is a balancing item which is calculated by subtracting the total non-recurrent and client device expenditure from the total reported IT & Communications costs.

Non-recurrent capex was calculated by reviewing projects, and identifying CAPEX for the following non-recurrent projects:

- Field Force automation
- Long Range digital Radio
- Operations Network security
- Mobile Radio Enhancement (P25).

Motor Vehicles

The Opex cost of motor vehicles was based on an extraction of transport transactions from the relevant transport costing elements. The non-related opex transport costs were then removed. The remaining relevant transactions contain an equipment number. Each equipment number has been aligned to its relevant RIN classification. The RIN classification is now stored and maintained in Ellipse as part of the equipment nameplate. In instances where an equipment number was not assigned to a transaction, the unassigned costs were apportioned across the RIN categories based on the already assigned proportions.

Hire vehicles (Hire Car, Hire Light Commercial Vehicle, Hire Heavy Commercial Vehicle and Other) have been identified separately due to their different total cost structure compared to Ergon Energy owned motor vehicles. Ergon Energy regards hire vehicle OPEX as a valid expenditure to benchmark its business performance, but not to directly benchmark against owned motor vehicle OPEX. Hire vehicles were identified in the abovementioned process by a unique set of equipment group identification numbers.

The actual registration and Insurance costs are not directly costed to the fleet item in the Ellipse system. Registration and Insurance costs are costed to each fleet item as part of a Fleet Management Fee. The Fleet management fee also includes depreciation. To remove depreciation from the opex exercise, the fleet management fee was removed in total and the registration costs were added back.

The Capex cost of motor vehicles was based on an extraction of transactions from the relevant fleet Work In Progress Activity accounts (C-Accounts) in the general ledger, with reference to the transport costing elements related to fleet equipment numbers in the general ledger. All transactions from all fleet related Work In Progress Activity accounts were extracted. All the transactions linked to fleet equipment numbers were identified from this extract from the general ledger and

isolated as the total CAPEX cost related to Fleet vehicles for the specific financial years in question.

The equipment number is assigned a RIN classification which is stored and maintained in Ellipse.

The transport transactions were then filtered to those relating to the specific identifier numbers associated to the above mentioned fleet assets.

The CAPEX costs relating to the equipment number and its relevant RIN classification were summed by regulatory year to provide the numbers for each group of equipment.

Finally, an SCS percentage was applied to the costs to meet the requirements of the RIN. The relevant percentage is that calculated for the reporting overheads leaving the cost applicable to Standard Control.

Other Expenditure

There is no capex or opex for other expenditure as Ergon Energy's total non-network capex is reported against specific categories.

Other NSP Nominated Categories

Office Furniture & Equipment

The capex on these items was sourced directly from the Annual Reporting RINs. As the capex is all by way of direct purchases and in accordance with the approved CAM these do not incur overheads.

As these items are individually of low value Ergon Energy does not incur expenditure on their repair and maintenance, hence opex is shown as zero.

Plant & Equipment

This category includes all non-vehicle items of plant and equipment including ladders, portable generators and a wide variety of other items.

The categorisation between the Annual Reporting RIN and the Category Analysis RIN is different where we have vehicle mounted equipment. However, analysis is performed to consolidate vehicle and vehicle mounted equipment (e.g. cranes) into the Vehicle category in accordance with the definition in the CA RIN. The remaining Vehicle and Plant and Equipment costs from the CA RIN are reported in the Plant & Equipment category in the CA RIN.

Crane Borer Plant HCV

The Opex cost of Crane Borer Plant HCV was based on an extraction of transport transactions from the relevant transport costing elements. The non-related opex transport costs were then removed. The remaining relevant transactions contain an equipment number. Crane Borer Plant HCV is one unit which is made up of two assets (Truck + Plant). Crane Borer Plant HCV is represented by an equipment group identification numbers [G-FVPLCB and G-FVHRT and G-

FVMRT]. The Opex costs relating to these equipment numbers and RIN classification of Crane Borer (HCV) were summed by regulatory year to provide the numbers for the template.

The Capex cost of Crane Borer Plant HCV was based on an extraction of transactions by equipment number and RIN classification of Crane Borer (HCV). SCS % has been applied for crane borer and other fleet assets as required.

The CAPEX costs relating to this equipment number and RIN classification of Crane Borer (HCV) were summed by regulatory year to provide the numbers for the specific equipment group.

Other Fleet Assets

Opex costs relating to EGI numbers for Trailers, Forklifts, Trenchers, Winches, Cranes, Small generators (not Network Generators), Self-propelled EWP (not mounted to trucks), compressors, All Terrain Vehicles and Quad Bikes have been included in “other fleet assets”. These fleet assets have been aligned to a RIN classification type of Other which is stored and maintained in Ellipse. An extraction of transport transactions from the relevant transport costing elements was sourced. The non-related opex transport costs were then removed. The remaining relevant transactions contain an equipment number. The equipment number is assigned a RIN classification which is stored and maintained in Ellipse. The transport transactions were then filtered to those relating to the specific EGI numbers associated to the above mentioned fleet assets. The Opex costs were then summed by regulatory year to provide the numbers for the template. SCS % has been applied for crane borer and other fleet assets as required.

Capex costs relating to EGI numbers for Trailers, Forklifts, Trenchers, Winches, Cranes, Small generators (not Network Generators), Self-propelled EWP (not mounted to trucks), compressors, All Terrain Vehicles and Quad Bikes have been included in “other fleet assets”. The assets have specific equipment numbers which are assets have been aligned to a RIN classification type of Other which is stored and maintained in Ellipse

Refurbishment/Rebuilt EWP(HCV)

Refurbished/Rebuild EWP CAPEX costs relates Elevated work platforms that have been refurbished instead of replaced under Ergons new strategy where EWP’s are replaced via a mix of replacement or refurbishment. Including this data separately provides increased transparency on how our fleet is financed.

The Capex cost of Refurbished/ Rebuilt EWP (HCV) was based on an extraction of transactions by equipment number and RIN classification from the transactions from the relevant fleet Work In Progress Activity accounts (C-Accounts) in the general ledger. SCS % has been applied for as required.

The rebuilt EWP's are identified by Equipment Number from the MEWP 10 year Major Inspection program report. The CAPEX costs relating to the identified Equipment Number is re-classified as a Refurbished/ Rebuilt EWP (HCV) and is summed by regulatory year to provide the numbers for the specific equipment group and disclosed separately.

Table 2.6.2 - Annual Descriptor Metrics- IT & Communications Expenditure

In order to obtain the information, it was necessary for Ergon Energy to request information from SPARQ Solutions who is the ICT provider for Ergon Energy.

Employee numbers were sourced from the monthly management report.

On the 1 July 2018, employees of the distribution network service providers Ergon Energy and Energex where transferred to Energy Queensland Limited (EQL) as the parent entity of the Energy Queensland Limited corporate group. EQL has entered into the Service agreement with Ergon Energy and Energex which effectively provides Energex and Ergon Energy's with a labour resource and this is subject to the direction and management of the DNSPs, although paid from EQL. Therefore, labour provided under the EQL service agreement is reported as in-house/internal labour, and not reported as outsourced labour.

The employee numbers reported in this RIN are reflecting employees whose payroll was processed in Ergon Energy's ERP system plus 50% of the EQL and Sparq employees. An SCS percentage was then applied.

User numbers were sourced from the Microsoft Active Directory report.

Number of Devices

The information was sourced using Microsoft applications - SCCM (Auto discover) and Active Directory.

Microsoft Active Directory report - Active Directory is a Directory Service product produced by Microsoft and used by SPARQ, Ergon Energy, and Energex to manage network user accounts and computer objects .All employees are given a user account within active directory.

Underpinning the directory service is a database which contains unique identifiers for each object as well as various attributes associate with those objects. Reports are run against this database to determine the number of employees, active computers etc.

SCCM (System Centre Configuration Manager) is a Microsoft product used for systems management. SCCM has the ability to auto discover devices on the network and determine what software etc. is running on them.

Software compliance reports are produced using a variety of sources. SCCM is a primary source for the majority of software however other discovery tools (e.g. Quest Discovery for databases) are used along with manual audits of applications based on vendor licensing models.

An SCS percentage was applied to all source data to meet requirements of the RIN. This was sourced from SCS% sourced from Template 2.11 Labour workings (refer Basis of Preparation for Template 2.11).

Table 2.6.3 - Annual Descriptor Metrics - Motor Vehicles

Data for the Annual Review is sourced from “Ellipse Full Listing Report”

Number in Fleet for each RIN category is actual information. Ergon Energy has applied a simple average to determine the result where there were different values over the year.

Average kilometres travelled is sourced from annual third part data regarding quarterly annualised use reports by fleet category and as per RIN grouping detailed below. The report is then filtered to be for contracts still running.

The CA RIN defined term for

- CAR equates to Ergon Energy Passenger Vehicle definition.
- LIGHT COMMERCIAL VEHICLE incorporates Ergon Energy’s Light Service Truck (LST) and 4WD and 2WD Light Commercial Vehicles definitions.
- ELEVATED WORK PLATFORM (HCV) equates to Ergon Energy MEWP Insulated definition + the HRT and MRT.
- HEAVY COMMERCIAL VEHICLE incorporates Ergon Energy HR/ MR and LR Trucks which do not have Crane Borer or Elevated work platforms attached.

7.5 Assumptions

Not applicable.

7.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER’s definition, for Table 2.6.1 for:

Buildings and Property;

- IT and Communications;
- Motor vehicles;

- Office furniture and equipment;
- Plant and Equipment;
- Crane Borer Plant HCV;
- Other fleet assets; and
- Other expenditure.
- Refurbishment/Rebuild EWP (HCV)

Actual Information, in accordance with the AER's definition for Table 2.6.2, has been provided for the following variables.

Employee numbers;

- User number; and
- Number of devices.

Ergon Energy has used Actual Information, in accordance with the AER's definition, for:

- Average Kilometres Travelled;
- Number purchased (Commissioned into service);
- Number Leased; and
- Number in Fleet.

7.7 Explanatory Notes

Not applicable.

8 BOP - 2.7 Vegetation Management

8.1 Scope of BOP

8.1.1 Table 2.7.1 - Descriptor Metrics by Zone

8.1.2 Table 2.7.2 - Expenditure Metrics by Zone

8.1.3 Table 2.7.3 - Descriptor Metrics across All Zones - Unplanned Vegetation Events

8.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Templates 2.7.1, 2 & 3.

8.3 Sources

Table 2.7.1 - Descriptor Metrics by Zone And Table 2.7.2 - Expenditure Metrics By Zone

All information is sourced from Ergon Energy corporate systems Ellipse and Smallworld and Queensland Government supported and managed zonal classifications.

The foundation for all costing lies within Ellipse providing and easily reconcilable planning, management and reporting view of this.

Table 2.7.3 - Descriptor Metrics across All Zones - Unplanned Vegetation Events

Information is sourced from FeederStat.

8.4 Methodology

Table 2.7.1 - Descriptor Metrics by Zone

Ergon Energy has established a methodology employed during previous reporting cycles of disaggregating the required CA RIN template categories from that derived directly from corporate systems. No additional derivation of significance (>5%) has been applied to this information and any variances from previous reporting are resultant from the continual updating of actual system data.

The number of zones reported changed in 2018-19 to one zone, compared to three zones reported in previous years. This aligns the approach used by both EQL DNSPs (Ergon Energy and Energex) as we continue to refine reporting for efficiencies.

Route Line Length

Total route line length is sourced from Smallworld. In FY previous to 18/19 total length was used as LIDAR was used as inspection tool. Ergon Energy now identifies VZ that are inspected in a FY and the total route line length only for the VZ inspected is entered into 2.7.1.

Number of Maintenance Spans

These numbers are determined by the information reported from the contractors' databases.

Urban

These numbers are determined by the information reported from the contractors' databases for urban Vegetation Zones.

Rural

These numbers are determined by the information reported from the contractor’s database for Rural Vegetation Zones.

Total Length of Maintenance Spans

Outputs of Route Line Length and Maintenance Span data are combined to report the length of Maintenance Spans. Please refer to above methodologies in determining these.

Maintenance spans are now captured from the data exported from the vegetation Contractors database.

Tree Trimming and Vegetation Corridor Clearance costs have been reduced as Audit and Inspection costs are deducted to be included in their own cell.

Lidar data is no longer used in any of the financial or physical information provided.

Length of Vegetation Corridors

Total length of Vegetation Corridors is equal to the total length of Rural maintenance spans.

Average Number of Trees per Maintenance Span

These numbers are determined by the information reported from the contractors' databases.

Average Frequency of Cutting Cycle

Average maintenance span cycle was calculated based on data sourced from the June monthly report for the Annual Vegetation Management Program (June 2019) taken from the Ellipse database (i.e. 2018-19 data was found in the June 2019 report).

A methodology was employed whereby:

- Average urban vegetation maintenance span cycle = (Sum of treated Urban vegetation zones cycle duration [Maintenance Schedule Task]/total number of Urban Vegetation Zones treated during regulatory (financial)year;
- Average rural vegetation maintenance span cycle = (Sum or treated Rural vegetation zones cycle duration [Maintenance Schedule Task]/total number of Rural Vegetation Zones treated during regulatory (financial) year.

Table 2.7.2 - Expenditure Metrics by Zone

All information is sourced from Ergon Energy corporate systems namely Ellipse. The foundation for all costing lies within Ellipse providing and easily reconcilable planning, management and reporting view of this.

Tree Trimming, Corridor Clearance, Audit and Inspection costs are captured as one amount. Vegetation Contractors record what percentage proportion of total costs they have for inspections and audit. These percentages are applied to total costs and the resulting figures are added. The remaining amount for Urban Vegetation Zones is added to Tree Trimming (excluding hazard trees). The remaining amount for Rural Vegetation Zones is added to Vegetation Corridor Clearance.

Hazard Tree Cutting Costs are recorded separately as they are variations to normal contract work.

In 2018-19 the costs and quantifies for ROAMES were included in Table 2.8 Routine 1a. POLE TOPS AND OVERHEAD LINES aligning treatment for EQL DNSPs (Energex and Ergon Energy). In previous years ROAMES costs and quantities were reported in Table 2.7 Vegetation Management. The maturity of the ROAMES program has now expanded its use from vegetation to now also incorporate an inspection of the poles, pole tops, services, overhead lines, a virtual line patrol and vegetation.

Table 2.7.3 - Descriptor Metrics across All Zones - Unplanned Vegetation Events

All recorded incidents which involve fire come from Feederstat. Customer Call data is analysed for jobs where fire was initiated by vegetation.

8.5 Assumptions

Not applicable.

8.6 Estimated or Actual Information

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in this Template.

8.7 Explanatory Notes

Not applicable.

9 BOP - 2.8 Maintenance (Actual)

9.1 Scope of BOP

9.1.1 Table 2.8.1 - Descriptor Metrics For Routine And Non-Routine Maintenance

9.1.2 Table 2.8.2 - Cost Metrics For Routine And Non-Routine Maintenance

9.2 Compliance with CA RIN Requirements

Ergon Energy has prepared the information provided in Template 2.8 - Maintenance, Table 2.8.1 and Table 2.8.2, in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

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

Ergon Energy has limited reporting in Template 2.8 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. In completing Table 2.8.1 - Descriptor metrics for routine and non-routine maintenance, Ergon Energy notes that:

- Where tasks were carried out for simultaneous inspection of assets and vegetation or for access track maintenance, this expenditure is reported under maintenance (not vegetation management)

- Ergon Energy has inserted additional Maintenance Asset Categories

- Communications, Meters and Ancillary Costs under the Various Assets, to represent costs incurred for routine and non-routine maintenance of communications and metering equipment and for the costs associated with rates, leases , rents and electricity charges for asset sites - Zone Substations and Communications sites. No units of measure were provided as this category captures a multitude of information not included in existing CA RIN categories. This is required for completeness of reflection of all routine and non-routine maintenance costs

- Access Tracks under Ground Clearance to represent tasks completed for routine and non-routine maintenance for access tracks along and adjacent to rural lines

These maintenance expenditure subcategories were added as it is material and not yet included in any other maintenance expenditure subcategory.

- Ergon Energy does not have any Dual Function assets, therefore records no Sub-transmission asset maintenance – for DNSPs with Dual Function Assets. Accordingly, all metrics are reported as Zeroes.

- All metrics are reported as zeroes in relation to Zone Substation Equipment Maintenance, for asset sub category Transformers - HV because all Zone Substation Transformers are reported within variable Transformers – Zone Substation

- Ergon Energy does not have any CBD feeders in its network, therefore all metrics in relation to Network Underground Cable Maintenance: By Location on asset subcategory CBD feeders is reported as zeroes.

- Furthermore Ergon Energy does not carry out any routine maintenance on underground cables as such and reporting of quantities is limited to the internal inspection of pillars related to low voltage cable reticulation.

- Ergon Energy ceased performing Line Patrols in 2015/16, hence the reduction in the Line Patrolled (Route KM). This program was an aerial or ground based fast patrol to identify major faults only on overhead network identified as high risk. The identification of major faults on all overhead network is now delivered as part of the ROAMES annual inspection of vegetation.

- Thermo-scanning and insulator cleaning have been included in the Assets Inspected/Maintained quantities for Pole Top and Overhead Lines.

- To determine the inspection and maintenance cycles, it is noted that the RIN requirements are to "use the highest-value (i.e. highest replacement cost) asset type in the asset group as the basis". Ergon Energy has interpreted this as the replacement cost of the total asset base for an asset type, not the replacement cost of a single asset. The 2014 Category Analysis RIN Explanatory Statement demonstrated expectations in this regard, by way of an example (page 114): in the case of poles, this is the pole and not the pole top structures such as the cross arms, insulators, and switches, as these structures/components could be younger. Ergon Energy also notes this also best reflects the basis for reporting of inspection and maintenance cycles.

- For all other variables the reporting of zero indicates that there was not maintenance performed in relation to that variable for that particular year. This is due to asset strategy change within the reporting period to start a new maintenance program or suspend or cease an existing one.

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

Ergon Energy has limited reporting in Template 2.8 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. Furthermore, the total amount for this Table has been reconciled with the total maintenance expenditure for Standard Control Services as classified in the year reported.

In completing Table *2.8.2 - Cost metrics for routine and non-routine maintenance*, Ergon Energy notes that:

- Where expenditure was incurred for simultaneous inspection of assets and vegetation or for access track maintenance, this expenditure is reported under maintenance (not vegetation management)
- Ergon Energy has inserted additional Maintenance Asset Categories
- Communications, Meters and Ancillary Costs under the Various Assets':, to represent costs incurred for routine and non-routine maintenance of communications and metering equipment and for the costs associated with rates, leases , rents and electricity charges for asset sites - Zone Substations and Communications sites.
- Access Tracks under Ground Clearance to represent costs incurred for routine and non-routine maintenance for access tracks along and adjacent to rural lines
- These maintenance expenditure subcategories were added as it is material and not yet included in any other maintenance expenditure subcategory.
- Ergon Energy does not have any Dual Function assets, therefore records no Sub-transmission asset maintenance – for DNSPs with Dual Function Assets. Accordingly, all metrics are reported as Zeroes.
- All metrics are reported as zeroes in relation to Zone Substation Equipment Maintenance, for asset sub category Transformers - HV because all Zone Substation Transformers are reported within variable Transformers – Zone Substation
- Ergon Energy does not have any CBD feeders in its network, therefore all metrics in relation to Network Underground Cable Maintenance: By Location on asset subcategory CBD feeders is reported as zeroes.
- In 2018-19 the costs and quantifies for ROAMES were included in Table 2.8 Routine 1a. POLE TOPS AND OVERHEAD LINES aligning treatment for EQL DNSPs (Energex and Ergon

Energy). In previous years ROAMES costs and quantities were reported in Table 2.7 Vegetation Management.

9.3 Sources

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

- Smallworld GIS
- Ellipse ERP

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

- All information for Routine Maintenance is sourced from Ergon Energy corporate systems namely Ellipse.

9.4 Methodology

Table 2.7.1 - Descriptor Metrics by Zone and Table 2.7.2 - Expenditure Metrics By Zone

Asset Quantity for the Period (excluding pole tops, service lines, lines patrolled and earth mats and SCADA)

Asset quantities come directly from our core systems (Smallworld GIS and Ellipse ERP) and are limited to regulated assets.

Smallworld supplies location and network hierarchy information as well as complete information on conductors (underground and overhead). The ERP provides physical information on assets.

Using the information in these systems we can align with best endeavours to CA RIN categories.

We take a snapshot of all the relevant data on 1st July for RIN reporting each year and data is produced using SQL scripts.

- Poles

This comes from our ERP and is a count of all regulated poles.

- Underground Cables

This comes from our GIS. Voltages are based on the feeder that the wire is attached to and aggregated. This is the route length and does not include vertical components (to align with other RIN templates).

- Distribution Substations

Transformer counts come from our ERP. It is a count of all (transformers) not in a zone substation (location comes from the GIS).

Switchgear counts come from our ERP and are a count of RMUs and ABS / reclosers.

Distribution substation properties are a count of the distinct properties that transformers are on (that are not inside a zone substation). This comes from a combination of GIS (property information) and ERP (transformer information).

- Zone Substation Equipment

All zone substation calculations form from our ERP and GIS. This GIS is used to work out if a piece of equipment is within a zone substation and the ERP is used for grouping assets based on class.

Property counts come from our ERP and report regulated zone sub sites that are Ergon Energy owned.

Zone substation transformer counts are a count of non-distribution transformers (house / local supply transformers) within a zone substation.

Distribution transformers is a count of all house transformers that are distribution transformers (house / local supply transformers) within a zone substation.

Other zone substation equipment is reported as non-transformer (distribution or power) of the following types within a zone substation: current transformers, circuit breakers, voltage transformers, earth switches, earth mates, battery banks, switch units, reclosers, isolators, cap banks and static var compensators.

- Protection Systems

This comes from our ERP and is a count of all protection relays.

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

In relation to Routine Maintenance Expenditure:

Ergon Energy has established a methodology employed during previous reporting cycles of disaggregating the required CA RIN template categories from that derived directly from corporate systems. No additional derivation of significance (>5%) has been applied to this information and any variances from previous reporting are resultant from the continual updating of actual system data.

The methodology Ergon Energy has applied lies in the collation of the building blocks of the Ellipse costing system – work orders are costed to at detailed task level with costs aggregated up to general ledger activity codes – in the case of Routine maintenance these codes are:

- Routine - 52100, 52120, 52135, 52140, 52150, 52160

The detail below this – task or standard job level for work orders is able to be disaggregated reliably and by definition into the variables for this template.

9.5 Assumptions

Refer to Section 9.4 Methodology for assumptions applied.

9.6 Estimated or Actual Information

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

Asset Quantity for the Period (excluding pole tops, service lines, lines patrolled and earth mats and SCADA) have been reported as actual information.

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

All information for Routine Maintenance is reported as Actual Information on the basis that:

- Data is derived directly from Ergon Energy corporate systems; and

No derivation has occurred that is materially significant – i.e. >5% of values.

9.7 Explanatory Notes

Not applicable.

10 BOP 2.8 Maintenance (Estimate)

10.1 Scope of BOP

10.1.1 Table 2.8.1 - Descriptor Metrics For Routine And Non-Routine Maintenance

10.1.2 Table 2.8.2 - Cost Metrics For Routine And Non-Routine Maintenance

10.2 Compliance with CA RIN Requirements

Ergon Energy has prepared the information provided in Template 2.8 - Maintenance, Table 2.8.1 - Descriptor metrics for routine and non-routine maintenance in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

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

Ergon Energy has limited reporting in Template 2.8 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. In completing Table 2.8.1 - Descriptor metrics for routine and non-routine maintenance, Ergon Energy notes that:

- Where tasks were carried out for simultaneous inspection of assets and vegetation or for access track maintenance, this expenditure is reported under maintenance (not vegetation management)
- Ergon Energy has inserted additional Maintenance Asset Categories
- Communications, Meters and Ancillary Costs under the Various Assets, to represent costs incurred for routine and non-routine maintenance of communications and metering equipment and for the costs associated with rates, leases , rents and electricity charges for asset sites - Zone Substations and Communications sites. No units of measure were provided as this category captures a multitude of information not included in existing CA RIN categories. This is required for completeness of reflection of all routine and non-routine maintenance costs
- Access Tracks under Ground Clearance to represent tasks completed for routine and non-routine maintenance for access tracks along and adjacent to rural lines

These maintenance expenditure subcategories were added as it is material and not yet included in any other maintenance expenditure subcategory.

- Ergon Energy does not have any Dual Function assets, therefore records no Sub-transmission asset maintenance – for DNSPs with Dual Function Assets. Accordingly, all metrics are reported as Zeroes.
- All metrics are reported as zeroes in relation to Zone Substation Equipment Maintenance, for asset sub category Transformers - HV because all Zone Substation Transformers are reported within variable Transformers – Zone Substation
- Ergon Energy does not have any CBD feeders in its network, therefore all metrics in relation to Network Underground Cable Maintenance: By Location on asset subcategory CBD feeders is reported as zeroes.
- Furthermore Ergon Energy does not carry out any routine maintenance on underground cables as such and reporting of quantities is limited to the internal inspection of pillars related to low voltage cable reticulation.
- Ergon Energy ceased performing Line Patrols in 2015/16, hence the reduction in the Line Patrolled (Route KM). This program was an aerial or ground based fast patrol to identify major faults only on overhead network identified as high risk. The identification of major faults on all overhead network is now delivered as part of the ROAMES annual inspection of vegetation.
- Thermo-scanning and insulator cleaning have been included in the Assets Inspected/Maintained quantities for Pole Top and Overhead Lines.
- To determine the inspection and maintenance cycles, it is noted that the RIN requirements are to "use the highest-value (i.e. highest replacement cost) asset type in the asset group as the basis". Ergon Energy has interpreted this as the replacement cost of the total asset base for an asset type, not the replacement cost of a single asset. The 2014 Category Analysis RIN Explanatory Statement demonstrated expectations in this regard, by way of an example (page 114): in the case of poles, this is the pole and not the pole top structures such as the cross arms, insulators, and switches, as these structures/components could be younger. Ergon Energy also notes this also best reflects the basis for reporting of inspection and maintenance cycles.
- For all other variables the reporting of zero indicates that there was not maintenance performed in relation to that variable for that particular year. This is due to asset strategy change within the reporting period to start a new maintenance program or suspend or cease an existing one.

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

Ergon Energy has limited reporting in Template 2.8 to Standard Control Services as clarified by the AER in its issue register for the Category Analysis RIN. Furthermore, the total amount for this Table has been reconciled with the total maintenance expenditure for Standard Control Services as classified in the year reported.

In completing Table 2.8.2 - Cost metrics for routine and non-routine maintenance, Ergon Energy notes that:

- Where expenditure was incurred for simultaneous inspection of assets and vegetation or for access track maintenance, this expenditure is reported under maintenance (not vegetation management)
- Ergon Energy has inserted additional Maintenance Asset Categories
- Communications, Meters and Ancillary Costs under the Various Assets':, to represent costs incurred for routine and non-routine maintenance of communications and metering equipment and for the costs associated with rates, leases , rents and electricity charges for asset sites - Zone Substations and Communications sites.
- Access Tracks under Ground Clearance to represent costs incurred for routine and non-routine maintenance for access tracks along and adjacent to rural lines

These maintenance expenditure subcategories were added as it is material and not yet included in any other maintenance expenditure subcategory.

- Ergon Energy does not have any Dual Function assets, therefore records no Sub-transmission asset maintenance – for DNSPs with Dual Function Assets. Accordingly, all metrics are reported as Zeroes.
- All metrics are reported as zeroes in relation to Zone Substation Equipment Maintenance, for asset sub category Transformers - HV because all Zone Substation Transformers are reported within variable Transformers – Zone Substation
- Ergon Energy does not have any CBD feeders in its network, therefore all metrics in relation to Network Underground Cable Maintenance: By Location on asset subcategory CBD feeders is reported as zeroes.

10.3 Sources

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

Estimated Information for variables was sourced from Ergon Energy's core systems on the basis of:

- Asset Quantity for the Period - Smallworld GIS - pole tops, service lines, lines patrolled and earth mats
- Asset Quantity Maintained – Ellipse
- SCADA – last years quantity estimate ± changes
- Asset Av Age – Smallworld GIS and Ellipse
- Inspection and Maintenance Cycle – Standard for Preventive Maintenance

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

Estimated information for Non-Routine Maintenance was sourced from Ergon Energy's core systems: Ellipse.

10.4 Methodology

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

Asset Quantity At Year End - pole tops, service lines, lines patrolled and earth mats

In relation to Asset Quantity Ergon Energy has developed an estimate on the following basis:

- An assumption has been used to determine the 'number of poles' for 'pole tops and overhead lines'. Ergon Energy's assumption is that for every 'pole top' there must be an associated pole, and thus the asset quantity at year end should be the same value for these two variables.
- An assumption has been used to determine the quantities for 'earth mats' against the asset category 'distribution substation - other equipment'. For every "installed transformer" for "distribution substation transformers", there must be an "earth mat" therefore these quantities should be the same.
- Ergon Energy has recorded the "SCADA & network control maintenance" asset population of Master Station and RTU from the "FIELD DEVICES" source data for Table 5.2.1.

Asset Quantity Maintained

In relation to Asset Quantity Maintained (Routine), Ergon Energy has developed an estimate on the following basis:

- Direct output from Ellipse disaggregated to align with best endeavours to CA RIN categories
- On this basis Ergon Energy considers that the best estimate has been provided.

In relation to Asset Quantity Maintained (Non-Routine), Ergon Energy has developed an estimate on the following basis:

- Direct output of costs at GL Activity from Ellipse disaggregated to align with best endeavours to CA RIN categories
- Ellipse captures information at a higher level (GL Activity) than for routine maintenance (Work Task Type). This means that Ergon Energy assessed proportionate numbers of work orders across the CA RIN categories from that higher level Ellipse collected data.
- The proportions disaggregated to CA RIN category are based on assessment of non-routine costs and number of work orders applied across known costs for that year. The proportions used to disaggregate costs were based on those derived through manual scrutiny of individual work orders created against the GL Activities for the previous years. The percentage proportions were confirmed as being applicable.

Ergon Energy considers that the best estimate has been provided.

Asset Average Age

In relation to Asset Average Age Ergon Energy has developed a process to estimate the ages of each asset as per methodology prescribed in the basis of preparation for template 5.2 (Asset Age Profile).

For SCADA assets were the average ages calculated by using the 2017-18 asset age profiles and progress them by the average age taking into account replacements and additions.

For Pole Tops and Overhead lines, same method as 2017-18, that until an improved data model is implemented the Pole age is the best estimate for Pole Top and Overhead line age.

For Earth Mat, same method as 2017-18, that until an improved data model is implemented the average age of Distribution Substation Transformers is the best estimate for Earth Mat age.

On this basis Ergon Energy considers that the best estimate has been provided.

Inspection and Maintenance Cycle

In relation to Inspection and Maintenance Cycle, Ergon Energy has developed an estimate on the following basis:

- Direct interpretation of the Standard for Preventive Maintenance disaggregated to align with best endeavors to CA RIN categories
- As per instruction, selection of the highest cost inspection/maintenance cycle where multiple cycles apply to the same CA RIN category

On this basis Ergon Energy considers that the best estimate has been provided.

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

In relation to Non-Routine Maintenance:

Ergon Energy has established a methodology employed during previous reporting cycles of disaggregating the required CA RIN template categories from that derived directly from corporate systems. No additional derivation of significance (>5%) has been applied to this information and any variances from previous reporting are resultant from the continual updating of actual system data.

The methodology Ergon Energy has applied lies in the collation of the building blocks of the Ellipse costing system – work orders are costed to at detailed task level with costs aggregated up to general ledger activity codes – in the case of Non-Routine maintenance these codes are:

- Non-Routine - 53100, 53120, 53135, 53140, 53150.

The detail below this – task or standard job level for work orders is able to be disaggregated reliably and by definition into the variables for this template.

Also in relation to Non-Routine Maintenance, Ergon Energy has developed estimates on the following basis:

- Direct output of costs at GL Activity from Ellipse disaggregated to align with best endeavours to CA RIN categories
- Ellipse captures information at a higher level (GL Activity) than for routine maintenance (Work Task Type). This means that Ergon Energy assessed proportionate levels of expenditure across the CA RIN categories from that higher level Ellipse collected data. The proportions disaggregated to CA RIN category are based on assessment of non-routine costs for applied across known costs for that year. The proportions used to disaggregate costs were based on

those derived through manual scrutiny of individual work orders created against the GL Activities for the previous years. The percentage proportions were confirmed as being applicable.

- Ergon Energy considers that the best estimate has been provided.

10.5 Assumptions

Refer to Section 10.4 Methodology for assumptions applied.

10.6 Estimated or Actual Information

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

For variable Asset Quantity Maintained, Financial asset management, physical asset management (and to an extent logistics) are separate processes and are not fully integrated under Ergon Energy's Enterprise Resource Planning (ERP) system. In particular, Maintenance tasks are initiated against an asset, however tasks are carried out under a bundled, high level costing work order. Thus the ability to directly access the individual maintenance costs for each task for each asset does not exist. So Ergon Energy has used suitable collation of actual figures from Ellipse to produce best endeavours estimates.

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

Financial asset management, physical asset management (and to an extent logistics) are separate processes and are not fully integrated under Ergon Energy's Enterprise Resource Planning (ERP) system. As a result, for variable Non-Routine Maintenance Ergon Energy does not maintain records at the required level of disaggregation and so used suitable collation of actual figures from Ellipse to produce best endeavours estimates.

Ergon Energy will continue to reduce the need for assumptions, and in accordance with the AER's CA RIN Definitions and Instructions are in the process of identifying opportunities for data quality improvement in support of the transition of data from Estimates to Actuals for future reporting periods.

10.7 Explanatory Notes

Not applicable.

11 BOP - 2.9 Emergency Response

11.1 Scope of BOP

11.1.1 Table 2.9.1 - Emergency Response Expenditure (Opex)

11.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.9, Table 2.9.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Regard has also been given to the AER's confirmation that where the instructions for template 2.9 ask for:

- Total emergency response opex
- Opex for major event (defined) and for major storms (defined)
- Opex for Major Event Days (MEDs) (defined).

The AER noted that:

- (B) is intended to capture costs where they can be attributable to particular events whereas (C) is to reflect all emergency response opex on days that were MEDs.
- The RIN instructions ultimately result in a double reporting of costs in (B) and (C) where an event for example, triggers an MED however AER expect to have visibility of opex on a daily basis under item (C) where the MED event is identified.
- AER also wouldn't necessarily expect daily opex for events identified in (C) to sum up to amounts reported for the same event in (B) given other activity on those days.

11.3 Sources

Actual Information for the variables was sourced from Ergon Energy's ERP – Ellipse.

11.4 Methodology

In respect of (B) MAJOR EVENTS O&M EXPENDITURE ($000'S), Ergon Energy notes:

- In order to obtain the information, it was necessary for Ergon Energy to select work orders from Enterprise Resource Planning (ERP) (Ellipse);

- Ergon Energy's Ellipse Code for Forced Maintenance (54100) has been used as it aligns to the AER's definition of Emergency Response.
- Data represents the total emergency response expenditure attributed to major events (clarified by the AER to mean an event triggering a 'major event day' - a term that is defined in the Service Target Performance Incentive Scheme (STPIS), including costs extending prior and past associated declared MED days as well as costs associated with Major Storms of Category 1 or above (but not necessarily result in an MED).
- These costs are calculated by accessing ERP (Ellipse) data contained in work orders created specifically for capture of costs for the specifically listed events. These work orders capture and collate all transactions applicable to the listed events
- Note that costs for major events occurring in a previous year that have flowed into the current year have been included.

In respect of (C) MAJOR EVENT DAYS O&M EXPENDITURE ($000'S), Ergon Energy notes:

- In order to obtain the information, it was necessary for Ergon Energy to select transactions from ERP (Ellipse) for each day identified as an MED.
- Emergency response expenditure incurred on the specific MED was reported by identifying daily opex incurred on each date.
- A sum of the emergency response expenditure incurred across the MED days related to a specific event was also calculated.
- Although consistent with the AER's guidance in this regard, Ergon Energy notes that under this approach, data reported:
    - captures total emergency response on these dates not only for abnormal events but also for normal daily events;
    - does not capture the total emergency response associated with the abnormal event which caused the MED but incurred in prior, or subsequent non-MED days.

11.5 Assumptions

Refer to Section 11.4 Methodology for assumptions applied.

11.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER’s definition, for all variables in Table 2.9.1.

11.7 Explanatory Notes

Not applicable.

12 BOP - 2.10 Overheads

12.1 Scope of BOP

12.1.1 Table 2.10.1 - Network Overheads Expenditure

12.1.2 Table 2.10.2 - Corporate Overheads Expenditure

12.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.10, Table 2.10.1 and Table 2.10.2, in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Overhead expenditure has been reported before it is allocated to services (Alternative Control Services (ACS) or Standard Control Services (SCS)) or direct expenditure, and before any part of it is capitalised.

Furthermore, regard has been given to the guidance provided from the AER in its Issues register, noting that Network Overheads has six compulsory categories and allowance for other (new) nominated categories (i.e. a new basis, break from previous Annual Performance RINs).

12.3 Sources

Table 2.10.1 - Network Overheads Expenditure

1. Base data sourced from Ellipse using SAP Hana to return net support costs (or “overhead”) for the 2018-19 financial year. Net support costs form the basis of the overhead pool. Report parameters are set as follows:

- District: EECL (Ergon Energy Corporation Limited) – the distribution entity;
- Responsibility Centre (RC): All (Business Unit groups responsible for expenses for a function/location);
- Activity: 62000 to 65040 (Type of work being undertaken, this range captures all “overhead” activities);
- Product: All (Product or service being provided);
- Element: 3300 to 8370 (excluding 8115, 8120CL, 8350, 8355) (Nature of the expense, this range captures all “overhead” elements).

In accordance with the 2015-16 to 2019-20 CAM adjustments to net support costs have been made to exclude all Training, Employee in Transition costs and costs associated with the Merger with Energex. The resulting data represents the total “overhead pool” by RC by year.

2. The Regulated Contribution report is then used to include the direct costs of other items the AER classifies as Network Overhead (but which Ergon Energy classifies as direct). Items include Meter Reading, Network operating costs, Demand Management, Customer Care activities, Training, ESO levies, and council rates for Network Assets.

Table 2.10.2 - Corporate Overheads Expenditure

1. Base data sourced from Ellipse using SAP Hana to return net support costs (or “overhead”) for the 2018-19 financial year. Net support costs form the basis of the overhead pool. Report parameters are set as follows:

- District: EECL (Ergon Energy Corporation Limited) – the distribution entity;
- Responsibility Centre (RC): All (Business Unit groups responsible for expenses for a function/location);
- Activity: 62000 to 65040 (Type of work being undertaken, this range captures all “overhead” activities);
- Product: All (Product or service being provided);
- Element: 3300 to 8370 (excluding 8115, 8120CL, 8350, 8355) (Nature of the expense, this range captures all “overhead” elements).

In accordance with the CAM, adjustments to net support costs have been made to include Fleet depreciation charges and exclude Training, Employee In Transition costs and costs associated with the Merger with Energex. The resulting data represents the total “overhead pool” by RC by year.

2. The Regulated Contribution report is then used to include the direct costs of other items the AER classifies as Overhead (but which Ergon Energy does not). Items include Self Insurance and Corporate Restructuring. Note in the 2015-16 to 2019-20 CAM, any under or over recovery of Overheads is not considered standard control.

12.4 Methodology

Table 2.10.1 - Network Overheads Expenditure

Network Overheads have been calculated by applying the underlying methodology of the CAM and Ergon Energy's associated overhead processes to actual support costs to derive actual overheads across the Network Overheads categories.

Allocation to Overhead Category

Each RC has been allocated to an overhead category within either Network Overheads or Corporate Overheads (AER defined terms), based on professional judgement as to the most appropriate category for each RC.

As required, data currently reported as 'Network Operating Costs' in Ergon Energy's Annual Reporting RIN has been collated / mapped to Network Overheads in the Category Analysis RIN, and disaggregated into the six mandatory subcategories:

- Network Management (support costs in those "Network RCs" which offer high level management support i.e. Executives and General Managers);
- Network Planning;
- Network Control and Operational Switching;
- Quality and Standard functions (including standards and manuals, compliance, quality of supply, reliability, network records (GIS), and asset strategy (other than Network Planning);
- Project Governance and related functions (including supervision, procurement, works management, logistics and stores);
- Other expenditure categories reflect annual reporting, with each category reported appropriately under Network Overhead. Specific categories that have been reported in the Overheads template which are normally treated as direct costs by Ergon Energy are:
    - Meter Reading;
    - Non-network Alternatives; and
    - Other Costs (including Network operating costs, Customer Service activities,
    - Distribution call centre, Market Transaction centre, NECF payments.
    - Training and other support costs in Network related RCs but which don't relate to network management, planning, control, quality and governance etc. as listed above).

Disaggregation by SCS, ACS, Unregulated Service Classifications

Network Overheads have been disaggregated across SCS, ACS and Unregulated Services classifications (Ergon Energy has no Negotiated distribution services) based on the CAM and CoS to determine the percentage allocation of each RC across the service types.

Under the CAM, the majority of Unregulated overheads, once derived, are charged as a fixed fee and should be disaggregated as such. Note the Isolated responsibility centres are allocated at 100% of actuals (not budget).

In the previous regulatory period, all Unregulated overheads were recorded as Corporate overheads. From 2015-16 however, with the RC mapping methodology applied, it has resulted in a split between Network and Corporate. This change is not material to years prior to 2015-16.

The ACS Operating expenditure (Opex) proportion is derived as the combination of:

(1) ACS maintenance activities as a proportion of Regulated maintenance activities that attract overhead; and

(2) ACS Customer care activities as a proportion of Regulated customer care activities.

Capitalised Overheads

Capitalised overheads have been calculated in accordance with Ergon Energy's current CAM, and previous CAMP, and are consistent with the capitalisation policy which has not changed from the previous regulatory period.

Ergon Energy considers it prudent to allocate overheads to Capital expenditures (capex) due to the size and nature of the capex. Capex is a key driver for the incurring of overheads and to not allocate overheads would undervalue the true cost of the Capital program.

Reconciliation

Due to adjustments to overhead rates throughout the year the above allocation does not result in an exact apportionment across service types and therefore a pro-rata adjustment has been applied to reconcile to actual overhead applied by service type. This has been achieved by pro-rating disaggregated values by year.

Table 2.10.2 - Corporate Overheads Expenditure

Corporate Overheads have been calculated by applying the underlying methodology of the CAM and Ergon Energy's associated overhead processes to actual support costs to derive actual overheads across the Corporate Overheads categories.

Allocation to Overhead Category

Each RC has been allocated to an overhead category within either Network Overheads or Corporate Overheads (AER defined terms), based on professional judgement as to the most appropriate category for each RC. For Corporate Overheads there has been a change in categories following corporate restructuring at the end of the previous year. Whilst some categories remain unchanged, a number of categories have been either added or deleted therefore impacting prior year comparisons.

Disaggregation by SCS, ACS, Unregulated Service Classifications

Corporate Overheads have been disaggregated across SCS, ACS and Unregulated Services classifications (Ergon Energy has no Negotiated distribution services) based on the CAM and CoS to determine the percentage allocation of each RC across the service types.

Under the CAM, the majority of Unregulated overheads, once derived, are charged as a fixed fee and should be disaggregated as such. Note the Isolated responsibility centres are allocated at 100% of actuals (not budget).

The ACS Opex proportion is derived as the combination of;

(1) ACS maintenance activities as a proportion of Regulated maintenance activities that attract overhead, and

(2) ACS Customer care activities as a proportion of Regulated customer care activities.

Capitalised Overheads

Capitalised overheads have been calculated in accordance with Ergon Energy's current CAM, and previous CAMP, and are consistent with the capitalisation policy which has not changed from the previous regulatory period.

Ergon Energy considers it prudent to allocate overheads to Capex due to the size and nature of the capex. Capex is a key driver for the incurring of overheads and to not allocate overheads would undervalue the true cost of the Capital program.

Reconciliation

Due to adjustments to overhead rates throughout the year the above allocation does not result in an exact apportionment across service types and therefore a pro-rata adjustment has been applied to reconcile to actual overhead applied by service type. This has been achieved by pro-rating disaggregated values by year.

12.5 Assumptions

Refer to Section 12.4 Methodology for assumptions applied.

12.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER's definition.

12.7 Explanatory Notes

Not applicable.

13 BOP - 2.11 Labour

13.1 Scope of BOP

13.1.1 Table 2.11.1 - Cost Metrics per Annum

13.1.2 Table 2.11.2 - Extra Descriptor Metrics For Current Year

13.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables as required by the RIN.

Ergon Energy has labour costs which are not catered for by the lines provided in Template 2.11 Labour, tables 2.11.1 and 2.11.2. These have been included in the template by merging them with other Labour Classifications as follows:

- Network workers labour costs that should be classified as either Corporate or Network Overheads labour costs (given the Ergon Energy practice for all blue collar employees to cost to overhead activities such as training, meetings, lost time, etc.) have been included in the Intern, Junior Staff, Non Field Work Apprentice classification;

- Non Electrical workers labour costs that should be classified as Direct Network labour costs (given the Ergon Energy practice for all employees who engage in Direct Network Activity to cost to the activity regardless of Labour classification) have been included in the Skilled Non Electrical Worker classification.

Ergon Energy has prepared the information provided in Template 2.11, Table 2.11.1 Cost Metrics per Annum and Table 2.11.2 Extra Descriptor Metrics for Current Year in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Only labour costs relating to the provision of Standard Control Services (SCS) are reported in the Template.

Ergon Energy confirms quantities of labour, expenditure or stand down periods are not reported multiple times across the tables.

13.3 Sources

All data has been sourced from Ergon Energy's Ellipse ERP system. This includes the following modules:

- Payroll
- Labour Costing / Timesheeting
- General Ledger

13.4 Methodology

A. Overheads

Corporate Overhead includes those activities that are not attributable to Maintenance, Capital or Network Overhead. E.g. Business Support – Finance, Safety, Human Resources, etc. - , Meetings, Lost Time (field staff), Technical Support, Property Services, Management Services, Training,

Network Overhead is defined as per AER guidance. Refer to section 8 below.

1. Allocate Ergon Energy Employees to RIN Labour Classifications

Ergon Energy has allocated employees to the RIN Labour Categories based on reporting level and occupation type.

2. Determine RIN Labour Classification Allocation Split for Labour payroll costs and hours by Responsibility Centre

Ergon Energy combines employee Ellipse payroll transactions with employee RIN Labour Classification allocations (point 1 above) to calculate Payroll labour costs & hours by RIN Classification per employee.

This data is aggregated to show total Payroll costs and hours per RIN Labour Classification.

The SCS component of these costs is determined by applying SCS % allocation.

3. Determine Overhead Work Order Labour Costing $ & Hours by RIN Classification and Responsibility Centre

Ellipse employee labour costing transactions for overhead activities were combined with the Employee RIN Labour Classification data (point 1 above). This was aggregated to determine the responsibility centre results.

These costs will have the RIN Overhead SCS % allocation applied to them to ensure they reflect only the employees SCS work component.

4. Determine Labour Costing Recoveries $ & Hours by RIN Classification and Responsibility Centre

Ellipse employee labour costing recovery transactions were combined with the Employee RIN Labour Classification data (point 1 above). This was aggregated to determine the responsibility centre results.

These costs will have the RIN Overhead SCS % allocation applied to them to ensure they reflect only the employees SCS work component.

5. Allocate Relevant Non Labour costs to Cost Centre and RIN Labour categories

Actual Ellipse GL annual balances were used as source data for the non Labour type costs – Training, Staff Awards, Personal Protective Equipment, Employee Subsidies, etc.

Ellipse payroll ordinary hours worked per cost centre per RIN Labour Classification (see above) were used to allocate these costs. It was assumed that Ordinary hours worked represented the consumption driver as this reflected the physical employee numbers that would consume these costs in the normal day to day running of the business.

These costs will have the RIN Overhead SCS % allocation applied to them to ensure they reflect only the employees SCS work component.

6. Redundancy Costs

Employee Redundancy payments & accruals are included as part of the Labour cost.

7. Labour Hire

Labour Hire $ annual expenditure was used as the source transactions.

An average $ per hour rate was determined using Supplier Panel information.

8. Determine SCS component of cost centre and RIN Labour classification costs and hours

SCS Opex % and SCS Capex % were determined as part of the RIN Overhead workings (refer Basis of Preparation for Template 2.10) and combined to determine a Total SCS % applied to each cost centre.

This Total SCS% was applied to the aggregate Payroll, Overhead activity Labour Costing, Labour Recovery, Labour Hire, Other costs and hours per cost centre and per RIN labour classification to calculate the SCS component for populating the RIN Labour template variables.

9. SCS Direct Network Activity defined as Overheads by RIN

Ellipse employee labour costing transactions for SCS Direct Network activities in Ergon Energy accounting defined as Network Overhead by the RIN guidelines was the source data. This was combined with Employee RIN Labour Classification data (point 1 above) and aggregated to produce results by RIN Labour Classification. Activities included in this data are activities such as Demand Management, Customer Service, Network Operating and Metering activities.

This is defined as Network Overhead for the purpose of the Labour template as per RIN guidelines.

This data does not need further breakdown as it is 100% SCS related activity.

B. Direct Network Activity

1. Direct Network activity Costs and Hours

Ellipse employee labour costing transactions for the SCS Direct Network activities were combined with the Employee RIN Labour Classification data (point 1 above).

This data does not need further breakdown as it is 100% SCS related activity.

C. Stand down Occurrences

Actual Employee stand down payroll transactions for 2018-19 were used as the base data of this section of the template

The RIN Labour Classification was added to the data as per Part A.1 above.

RIN Overhead Categories and SCS Activity % were added based on the RIN Overhead workings data.

The data was aggregated to derive an estimate of SCS Stand downs by Overhead category and Direct Network activity.

All Skilled Electrical Worker, Apprentice and Non Skilled Electrical Worker Stand Downs were assumed to be Direct Network related.

D. Calculation based on assumption of 1885 hours per FTE ASL

Ergon Energy's normal business reporting uses the FTE assumption of 1885 hours or 9 day fortnight engagement. This reflects the Full Time Employment definition in Ergon Energy current Enterprise Bargaining Agreement.

It is assumed that the total time (Ordinary + Overtime) equals 1885 as per above.

Calculation of the number of ASL as follows:

(SCS Ordinary Hours + SCS Overtime Hours)
1885 hours

E. Calculate Per ASL Values

- **Average Productive Hours** per ASL assumed as 1885 as per above
- **Stand-Down Occurrences per ASL =** number of stand down occurrences, per annum per labour category / ASL count.
- **Stand-Down Occurrences** were sourced from Ellipse payroll data.
- **Average Productive Hours per ASL-Ordinary Time** = 1,885 Hours * *(Ordinary ASL / Total ASL*)
- **Average Productive Hours per ASL-Overtime** = 1,885 Hours * *(Overtime ASL / Total ASL*)
- **Hourly Rate per ASL-Ordinary Time** = Ordinary Time Cost excluding Redundancy costs / Ordinary Time Hours

Redundancy costs have are included in Total Labour Expenditure costs

Redundancy costs excluded from hourly rate as these costs do not form part of "on the job" costs.

- **Hourly Rate per ASL-Overtime** = *Overtime Cost / Overtime Hours.*
- **Total Labour Cost =** the aggregate of all defined Labour costs.

These calculations represent the most appropriate alignment of Ergon Energy source data with the disclosures prescribed within the RIN requirements.

F. Allocation of costs

This occurs in two instances.

1. Costs are not identifiable by employee

This occurs where the cost source data is not employee specific.

Costs of this type will be pro rata allocated using the Labour Category Ordinary Hours per responsibility centre as a basis of consumption.

2. Variance between model results and general Ledger Balances

This occurs where the building blocks of the model differ to the total of all transactions in the general ledger due to transactions not able to be determined at employee level as per steps outlined above

Costs of this type will be pro rata allocated using the Labour Category Ordinary Hours per responsibility centre as a basis of consumption.

13.5 Assumptions

Refer to Section 13.4 Methodology for assumptions applied.

13.6 Estimated or Actual Information

The data in the template is based on Actuals. No estimates have been used.

13.7 Explanatory Notes

As discussed with the AER, on 1 July 2018, employees of the distribution network service providers Ergon Energy and Energex where transferred to Energy Queensland Limited (EQL) as the parent entity of the Energy Queensland Limited corporate group. EQL has entered into the Service agreement with Ergon Energy and Energex which effectively provides Energex and Ergon with a labour resource and this is subject to the direction and management of the DNSPs. As clarified by the AER, EQL employee costs under the Service agreement have been treated as in-house labour (not related party labour).

14 BOP - 2.12 Input Tables

14.1 Scope of BOP

14.1.1 Table 2.12 Input Tables

14.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 2.12 Table 2.12.1 Input Tables in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

It is noted that Table 2.12.1 Input Tables does not represent an exhaustive list of expenditure. The summation of input costs for each category do not reconcile to total expenditures amounts reported in all respective templates given limitations of the template. It is also noted there are no requirements in the RIN regarding reconciliation that involve Template 2.12.

- On 30 June 2016, the Energy Queensland Group was formed with the parent being Energy Queensland Limited (EQL) and 100% owned subsidiaries of Ergon Energy Corporation Limited (EECL) and Energex Limited (Energex). At that time EECL had 100% owned subsidiaries Ergon Energy Queensland Pty Limited (EEQ) and Ergon Energy Telecommunications Pty Limited (EET), and a 50% interest in a jointly controlled entity SPARQ Solutions Pty Ltd (SPARQ). EEQ is a non-competing electricity retailer; EET is a wholesale telecommunication service provider; and SPARQ is an information, communications and technology service provider.
- A corporate restructure occurred effective 1 December 2017 whereby EQL took up 100% ownership of these subsidiaries.
- EECL provides management services to EEQ and EET as these entities do not have their own management structures. EECL pays SPARQ a charge in accordance with service level agreements which is captured as a corporate overhead.
- EQL is subject to common control as a Queensland Government Owned Corporation (GOC), with all shares held by shareholding Ministers on behalf of the State of Queensland and transacts with other State of Queensland controlled entities. However, the Queensland Government and State of Queensland controlled entities are not considered related parties for the purposes of the CA RIN due to the specific exclusion of government departments in the definition.

- EECL's corporate overheads and non-network IT and communications costs include related party costs incurred from SPARQ. As SPARQ operates on a cost pass through model, there are no Related Party Margins to report. The total value of related party transaction with SPARQ were identified using General Ledger codes established for that purpose

- The total value of related party transactions with Energex was also identified using General Ledger codes established for that purpose. There are no margins charged on these intercompany transactions.

- Related Party disclosures represent transactions between entities of the EQL Group. Where applicable, costs are allocated to DNSPs on a 50/50 basis.

14.3 Sources

Ergon Energy has provided Estimated Information, in accordance with the AER's definition for all variables in Table 2.12 Input Tables for all regulatory years.

14.4 Methodology

Base data sourced from Ellipse was used to establish a total and the initial split between direct material cost, direct labour cost, contract cost and other costs. Cost elements within the chart of accounts were used to allocate costs between direct material cost, direct labour cost, contract cost and other costs. The cost elements were not sufficiently detailed to provide the correct costs to meet the Category Analysis RIN's definition for direct labour cost, contract costs and other costs, because direct labour is recorded at average standard labour cost rates (not actual incurred payroll costs) and reconciled in aggregate.

The labour data compiled for Template 2.11 was used to adjust labour costs in Template 2.12 for corporate and network overheads and direct labour costs in order for them to balance to the labour costs shown in Template 2.11.

Other costs were then calculated as a balancing item after deducting direct materials, adjusted direct labour and contractor costs. This ensured that the row totals remained unchanged.

No apportionment was required to be made for direct material cost. It was identified within the base data sourced from Ellipse using specific cost elements.

Total emergency response expenditure [contained in Template 2.9 Emergency Response] was not included in the protected Template 2.12 required for submission. Accordingly, these costs were not included because additional line items could not be inserted into Template 2.12 and no other line item was appropriate.

However Ground clearance - access tracks and various assets contained in Template 2.8 were mapped to the respective Routine or Non Routine maintenance “Other” categories in the Input tables template.

Furthermore, the following items in Template 2.6 Non-Network that are without a dedicated line available in the Input tables template, were mapped to the Other Non-network expenditure line item:

- Office Furniture and Equipment
- Plant and Equipment

14.5 Assumptions

Refer to Section 14.4 Methodology and Section 14.6 Estimated or Actual Information for assumptions applied.

14.6 Estimated or Actual Information

It was not possible to use Actual Information, and an estimate is required because the corporate Enterprise Resource Planning (ERP) and associated processes were not envisioned or configured with the level of detail requested by the AER in mind.

Ergon Energy considers that it has used its best endeavours to provide its best estimate of direct material cost, direct labour cost, contract cost and other costs based on the available data in the Ellipse General Ledger and the AER Category Analysis RIN’s definitions.

14.7 Explanatory Notes

Not applicable.

15 BOP - 4.1 Public Lighting

15.1 Scope of BOP

15.1.1 Table 4.1.1 - Descriptor Metrics over Year

15.1.2 Table 4.1.2 - Descriptor Metrics Annually

15.1.3 Table 4.1.3 – Cost Metrics

15.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 4.1 - Public Lighting, Table 4.1.1 Table 4.1.2 and Table 4.1.3 for current year (2018-19) in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Table 4.1.1 - Descriptor Metrics for Current Year

As advised by the AER, Ergon Energy in not required to comply with paragraph 17.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN.

Data has not been reported in relation to gifted assets, or public lighting services which have been classified as contestable. However, non-contestable, regulated public lighting services reported includes work performed by third parties on behalf of Ergon Energy.

Finally, Ergon Energy does not have negotiated services in relation to public lighting therefore no metrics are included in this regard.

Table 4.1.2 - Descriptor Metrics Annually (Volumes and Expenditure)

Ergon Energy has left blank, the cells for *Volume of GSL Breaches* and *GSL Payments*. Ergon Energy does not have a GSL scheme for Public Lighting, and is therefore not required to report data in respect of GSLs. However the cell is not shaded orange for blacking out as per instructions. Given a 'zero' is a valid and logical answer, but no scheme exists for Ergon Energy, it is not appropriate to enter 'zero'.

Ergon Energy has not distinguished between expenditure for public lighting services between Standard and Alternative Control Services when completing Template 4.1 Table 4.1.2. Furthermore, expenditure has not been distinguished between capital expenditure (capex) and operating expenditure (opex).

This was further clarified by the AER in its issues register, where it noted that all items of capex and opex that were necessary to provide the services listed in templates 4.1 to 4.4 were to be included. In this regard, costs have been measured as the direct cost, excluding overheads.

Expenditure has been reported as a gross amount, by not subtracting customer contributions. Furthermore, data has not been reported in relation to gifted assets, or public lighting services which have been classified as contestable.

However, non-contestable, regulated public lighting services reported includes work performed by third parties on behalf of Ergon Energy.

Finally, Ergon Energy does not have negotiated services in relation to public lighting therefore no metrics are included in this regard.

15.3 Sources

Table 4.1.1 - Descriptor Metrics for Current Year

Actual Information for the variables was sourced from Public Lighting Management database (PLUMS). PLUMS is an internal system utilising several other Ergon Energy information systems to collate information in relation to public lighting assets and asset information.

Table 4.1.2 - Descriptor Metrics Annually (Volumes and Expenditure)

Actual Information for Light Installation, Replacement and Maintenance Expenditure was sourced from Ellipse General Ledger extracts.

Actual information for Light Installation, Replacement and Maintenance volumes was sourced from Ellipse Requisition data report extracts and Road Patrol reports.

Actual Information for ‘mean days to rectify / replace public lighting assets’ and ’volume of customer complaints’ was sourced from Cherwell.

TABLE 4.1.3 – COST METRICS

Information is sourced from Ellipse through running of several reports to assist in arriving at a best estimate.

15.4 Methodology

Table 4.1.1 - Descriptor Metrics for Current Year

Data was extracted from PLUMS database. Pivot tables were then developed from this extract to identify Public Lighting assets that were established in the database at the end of each regulatory year (financial year) for Ergon Energy Owned and Operated (former Rate 1) lights.

Commencing in 2018-19 we changed the presentation of DNSP nominated 'light types', compared to the prior year. Volumes are now grouped into light types, as opposed to light type by size. This aggregation presents more useful information to the user when assessing the public lighting asset base.

These pivot tables also included a breakdown by the light type classification.

It is assumed that the PLUMS data is an accurate record of actual assets.

Table 4.1.2 - Descriptor Metrics Annually (Volumes and Expenditure)

Total Public Light installation, replacement and maintenance expenditure was calculated by assigning relevant Activity Codes against the corresponding RIN sub-category as below and extracting the general ledger direct costs from Ellipse Financial reporting.

Table 15-1 Activity Code Mapping

RIN Sub Category	Activity Codes
Light Installation	C2040 Augmentation C2060 Domestic & Rural Cust Requested Works C2070 Commercial & Industrial Cust Req Works C2120 Street Lighting Constructed C2260 Real Estate Development Constructed
Light Replacement	C2000 Network Refurbishment C2130 Street Lighting Refurbishment
Light Maintenance	52180 Preventive Reg Streetlights 53180 Corrective Reg Streetlights 54180 Forced Reg Street Light Maint 56200 Alternative – Other Costs Customer Service - Removal/rearrange public light assets

In relation to Light Installation Major/ Minor and Poles Volume, Ergon Energy has developed the following approach:

It was necessary for Ergon Energy to apply a stock code to all items to reflect what that item was used for. An Ellipse report was run to identify transactions associated with the key stock items with a street light stock section.

Transactions were filtered to remove activities for external work, internal movements between stores and contractor returns

The following activity codes were identified as related to Ergon Energy's key Streetlight Installation activity:

- C2040 - Augmentation
- C2060 - Domestic & Rural Customer Requested Works
- C2070 - Commercial & Industrial Customer Requested Works
- C2120 - Street Lighting Constructed
- C2260 - Real Estate Development Constructed

A report called "RIN_Reporting_Streetlighting" has been produced to collate the volume of Streetlight components issued from Stores and the material cost associated with the above activity codes.

Major Luminaires, Minor Luminaires, brackets and all poles values were then totaled for Light Installation subcategory totals.

The data collected was only for regulated, non-contestable streetlights as per the RIN definition

In relation to Light Replacement Major/ Minor and Poles Volume, Ergon Energy used a similar approach to Light Installation volumes above.

The following activity codes were identified as related to Ergon Energy's key Streetlight Replacement activity:

- C2000 - Network Refurbishment
- C2130 - Street Lighting Refurbishment

A report called "RIN_Reporting_Streetlighting" has been produced to collate the volume of Streetlight components issued from Stores and the material cost associated with the above activity codes.

Major and Minor luminaires, lamps, brackets as well as all poles values were then totaled for Replacement subcategory totals.

In relation to Light Maintenance Major/ Minor and Poles Volume, Ergon Energy used a similar approach to Light Installation volumes above.

The following activity codes were identified as related to Ergon Energy's key Streetlight Replacement activity:

- 52180 - Preventive Reg Streetlights
- 53180 - Corrective Reg Streetlights
- 54180 - Forced Reg Street Light Maint
- 56200 - Alternative – Other Costs – Customer Service - Removal/rearrange public light assets

A report called "RIN_Reporting_Streetlighting" has been produced to collate the volume of Streetlight components issued from Stores. The total of Road Patrols Major Streetlight inspections was also added to the Major Lights volume.

Poles values for all maintenance types of Preventative, Corrective and Forced utilised the same methodology as Corrective and Forced Maintenance units above.

The data collected was only for regulated, non-contestable streetlights as per the RIN definition.

In relation to repair of faulty street lights, all Work Orders, Work Requests and Field Force Automation (FFA) jobs created in 2018-19 were collated and cross referenced. Work Orders were cleaned where:

- Start dates were before 01/07/18
- End dates still open at time of report run
- Work Order not corrective streetlight maintenance
- Work Order for multiple/ bulk repair / inspection
- Work Order cancelled
- Work Order duplicates

Work Order Start dates were calculated and cleansed by using a preference of: Work Request - Work Order – FFA Device as per the system processes.

Work Order End dates were calculated and cleansed by using a preference of FFA -Work Order – Work Request.

In relation to Mean Days to rectify/replace Public Lighting assets (days) the average days to complete of cleansed corrective streetlight maintenance work orders was calculated.

Table 4.1.3 – Cost Metrics

Ergon Energy has developed an estimate based on the following approach:

Average Unit Cost for Major and Minor Light Installation, Replacement and Maintenance for 2018-19.

Several reports were run from Ellipse to provide primary information on:

- Volume of lamps, luminaires, brackets and poles linked to Installation / Replacement Activity Codes for each period by breakdown into Major/ Minor light type subcategory
- Average cost of lamps, luminaires, brackets and poles linked to Installation / Replacement Activity Codes for each period by breakdown into Major/ Minor light type subcategory
- General Ledger information for the ratio of Material Cost to Direct costs for Installation and Replacement activity codes.

An average weighted volume methodology was used to calculate the number of major components (lamps, luminaires, brackets and poles) used in an average installation or replacement of major and minor streetlights. The data was extracted from Ellipse requisitioning data for respective activity codes used for Installations and Replacements.

The Average unit price for lamps, luminaires, brackets and poles issued is then entered against the average weighted volume of materials for the average Material Price for each item.

The average Material Price is multiplied by the average ratio of Material Costs from the Requisition Reports against Direct Costs sourced from the General Ledger over the 2017-18 period.

Assumptions made for this data includes:

- Streetlight Installation has been based on Luminaire volume as the primary value for calculation of Number of Streetlights and the basis for weighted average volume between the asset categories.
- Streetlight Replacement has been based on Lamp volume as the primary value for calculation of Number of Streetlights and the basis

Minimum Requirements Ergon Energy Response for weighted average volume between the asset categories.

- Streetlight Maintenance has been based on Lamp volume as the primary value for calculation of Number of Streetlights and the basis for weighted average volume between the asset categories.
- Only Lamps, Luminaires, poles and brackets have been included in the material cost. Other materials have been excluded due to the difficulty in extracting base information to be

included in the estimate. These four categories are the main components in Streetlight installation.

Ergon Energy considers that the best estimate has been provided for the above values as the reporting systems are unable to expand to further granular levels without a decline in integrity of estimates methodology used.

15.5 Assumptions

Refer to Section 15.4 Methodology for assumptions applied.

15.6 Estimated or Actual Information

Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 4.1.1 and Table 4.1.2 for the period 2018-19

Ergon Energy has used Actual Information, in accordance with the AER's definition, for:

- Total Light Installation Volumes and Expenditure for 2018-19
- Total Light Replacement Volumes and Expenditure for 2018-19
- Total Light Maintenance Volumes and Expenditure for 2018-19
- Mean Days to rectify/replace Public Lighting assets (days) for the period 2018-19
- Volume of Customer Complaints for 2018-19

Table 4.1.3 is reported as estimates for reasons explained above in Section 15.4 Methodology.

15.7 Explanatory Notes

Not applicable.

16 BOP - 4.2 Metering

16.1 Scope of BOP

16.1.1 Table 4.2.1 - Metering Descriptor Metric

16.1.2 Table 4.2.2 - Cost Metrics

16.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Table 4.2.1 - Metering Descriptor Metric (Volumes)

Ergon Energy notes that it does not have regulated metering services relating to meter categories Type 4 and Type 5. Type 5 metering is not permitted in Queensland as per the National Metrology Procedures Part A. Ergon Energy has identified this in the basis of preparation. Accordingly, metrics have been populated as 'zeroes' in this regard.

As advised by the AER, Ergon Energy has not had regard to paragraph 16.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN.

Ergon Energy has not distinguished Metering services between Standard and Alternative Control Services when completing Template 4.2, Table 4.2.1.

Data has not been reported in relation to metering services which have been classified as contestable. Non-contestable, regulated metering services have been reported by Ergon Energy including work performed by third parties on behalf of Ergon Energy.

Impacts due to introduction of Power of Choice (PoC) on 1st December 2017 are noticeable in some line items where applicable for volumes.

Table 4.2.2 - Cost Metrics (Expenditure and Volumes)

Ergon Energy notes that it does not have regulated metering services relating to meter categories Type 4, Type 5 nor Type 7. Type 5 metering is not permitted in Queensland as per the National Metrology Procedure Part A. Type 7 metering is contestable work and has been excluded. I.e. watchman lights. Ergon Energy has identified this in the basis of preparation. Accordingly, metrics have been populated as 'zeroes' in this regard.

Ergon Energy has prepared the information provided in Template 4.2 - Metering, Table 4.2.2 - Cost Metrics in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Ergon Energy has not distinguished between expenditure for Metering services between Standard and Alternative Control Services when completing Template 4.2, Table 4.2.2. Furthermore, expenditure has not been distinguished between capital expenditure (capex) and operating expenditure (opex).

This was further clarified by the AER in its issues register, where it noted that all items of capex and opex that were necessary to provide the services listed in templates 4.1 to 4.4 were to be included. In this regard, costs have been measured as the direct cost, excluding overheads.

Data has not been reported in relation to metering services which have been classified as contestable. Non-contestable, regulated metering services have been reported by Ergon Energy including work performed by third parties on behalf of Ergon Energy.

Impacts due to introduction of Power of Choice (PoC) on 1st December 2017 are noticeable in some line items where applicable for volumes and expenditure.

Finally, consistent with guidance provided by the AER in its issues register in relation to certain meter services costs, Ergon Energy notes that:

- meter data costs that could be attributable to specific meter reading activities has been reported as part of the cost for the relevant meter reading services category; and
- data processing costs which could not be attributable to a specific activity has been reported in the “other costs (metering)” category.

16.3 Sources

Table 4.2.1 - Metering Descriptor Metric (Volumes)

Ergon Energy has used information primarily sourced from Business Objects Report (B-NE-NC-0696 Metering Counts) which utilises data from the Meter Asset Register System (MARS) and PEACE. For this RIN the report data was refreshed on 01/07/2019. Ellipse Reports and External Billing extracts were also utilised for identifying sites outside of the RIN definitions.

Table 4.2.2 - Cost Metrics (Expenditure and Volumes)

Sources of Information for the following variables are noted below:

- Meter Purchases volumes were sourced from Supplier Performance reports based on Ellipse data.
- Meter Purchases expenditure was sourced from Supplier Performance reports based on Ellipse data.

- Meter Testing volumes were sourced from Ellipse reports based on Activity Codes, Standard Jobs and Work Orders. The volume of single phase tests completed is out of Process Tracking Job data from Peace.
- Meter Testing expenditure was sourced from Ellipse reports based on Activity Codes, Standard Jobs and Product Code mapping.
- Meter Investigation volumes were sourced from mapping of Ellipse Financial Codes and Standard Jobs against Process Tracking Job data from Peace Reporting extracts.
- Meter Investigation expenditure was sourced from Ellipse reports based on Activity Codes, Standard Jobs and Product Code mapping.
- Scheduled Meter Reading expenditure was sourced from Ellipse reports based on Activity Codes, Standard Jobs and Product Code mapping.
- Scheduled Meter Reading volumes were sourced from Operational reports based on data referencing existing and historical annual meter reading reports and excludes self reads and annual reads for scheduled reading purposes.
- Special Meter Reading volumes were sourced from mapping of Ellipse Financial Codes and Standard Jobs against Process Tracking Job data from Peace Reporting extracts.
- Special Meter Reading expenditure was sourced from Ellipse reports based on Activity Codes, Standard Jobs and Product Code mapping.
- New Meter Installations volumes were sourced from mapping of Ellipse Financial Codes and Standard Jobs against Process Tracking Job data from Peace Reporting extracts.
- Meter Replacement volumes were sourced from mapping of Ellipse Financial Codes and Standard Jobs against Process Tracking Job data from Peace Reporting extracts.
- Meter Replacement expenditure was sourced from Ellipse Reports based on Activity Codes mapping.
- Meter Maintenance expenditure was sourced from Ellipse Reports based on based on Activity Codes, Standard Jobs and Product Code mapping.
- Meter Maintenance volumes were sourced from mapping of Ellipse Financial Codes and Standard Jobs against Process Tracking Job data from Peace Reporting extracts. As well as Activity Codes, Standard Jobs and Work Order Description data.

16.4 Methodology

Table 4.2.1 - Metering Descriptor Metric (Volumes)

In relation to Single Phase Meter population and Multiphase Meter population, report B-NE-NC-0696 Metering Counts accesses MARS & Peace data from SAP Hana. The Filters applied:

- Exclude Remote Generation TNI; NMI Class Generator, Wholesale; non-market NMI; meter model Unknown or Virtual meter.
- Include only Meter provider ERGONMP, asset status Installed.
- The subtotal for each retailer is used to exclude Tier 2 large NMIs.
- Meter model type complex are installed with current transformers, simple will connect to the whole of the supply current.
- Card meters are also whole current.

Table 4.2.2 - Cost Metrics (Expenditure and Volumes)

In order to obtain the information, it was necessary for Ergon Energy to take the following approach:

- Meter Purchase volumes and expenditure - was summarised from the Supplier Performance reports. There were no meter purchases for regulated metering. A RITI (Receive Inspect Test Issue) process was not utilised during this period and no testing of equipment costs are involved for testing of meters during the purchasing process. NOTE: Metering Purchase expenditure is not considered capex or opex as the cost is not realised until the installation of the meter and is then costed against the correct activity code (ACS, SCS, unregulated or external).

- Volumes and expenditure for other categories have been mapped against the relevant RIN categories through a CA RIN Index worksheet which provided Lists for the CA RIN Volumes and CA RIN Expenditure worksheets have been collated from PTJ extract from Peace reporting the total expenditure and volume of relevant PTJs.

- Expenditure has been allocated by an Ellipse extract of Activity Codes involving all or parts of regulated metering activities. The Standard Jobs of the transactions were used as the primary factor of categorisation into RIN subcategories. Activity Code and Product Code were used as secondary factors for categorisation.

- Meter Testing expenditure was extracted from Ellipse Reports by mapping of related expenditure using Activity Code 52130 Preventive Maintenance Regulated Meters with cross referencing to mapped Standard Jobs from the CA RIN index (MMP050 & MMP010). The In-situ testing work order costs were also included from Activity Code 53130.

- Meter Testing volume data was developed on the assumption that each work order raised from the above cross reference was equivalent to one Meter Test. The in Situ meter testing program single phase volume is taken from count of the relevant PTJ class.
- Meter Investigation expenditure is summarised from the CA RIN Index for relevant Standard Jobs and Product Codes for Meter Queries / Investigation and Revenue Protection related activities.
- Meter Investigation volumes is summarised from the CA RIN Index for relevant Standard Jobs and PTJ's for Meter Queries / Investigation and Revenue Protection related activities.
- Scheduled Meter Reading expenditure is summarised from Ellipse Reports for Activity Code 56020 Mass Market Meter Reading and Standard Jobs QNOMRB, QCEMRB and QSOMRB which represents the collection of data cost. It includes work orders for depot read in regions north and south (none for central).
- Scheduled Meter Reading volumes are summarised from monthly MVRS reports with 12 months rolling data. This is data sourced from MVRS and consolidated into the end of month operational reports. Because depot reads are entered into MVRS they are include in the statistics. Self reads, annual reads for scheduled reading purposes have been excluded.
- Special Meter Reading expenditure is summarised from Ellipse Reports for Activity Code 56000 Special Meter Reads under product code 8080
- Special Meter Reading volumes are summarised from the CA RIN Index for relevant Standard Jobs and PTJ's for the Special Read expenditure above. The methodology introduced last year has been applied to encompass all Special Read PTJs and not exclude re-energisation reads. This is consistent with the definitions in Appendix F and aligns to reporting in T4.4 Quoted Services.
- New Meter Installations volume is the number of FB SSW NC (B2B – New Connection) PTJ's on POC Exempt NMIs matched with a MARS meter install event, Isolated Feeders and Cancelled / Incomplete Market Status have been excluded.
- Meter Replacement expenditure was provided from Ellipse Reports using Activity Code C2245 (Metering Replacement (NICW).
- Meter Replacement volumes were CA RIN Index for relevant Standard Jobs and PTJ's for the Meter Replacement expenditure above.

- Meter Maintenance expenditure is summarised from the CA RIN Index for relevant Standard Jobs and Product Codes for corrective meter maintenance activities.
- Meter Maintenance volumes summarised from the CA RIN Index for relevant Standard Jobs and PTJ's for corrective meter maintenance activities. Work Orders from Activity Code 53130 were checked for compliance to RIN definition.

16.5 Assumptions

Refer to Section 16.4 Methodology for assumptions applied.

16.6 Estimated or Actual Information

Refer to Section 17 BOP – 4.2 Metering (Estimate) for estimated information.

Ergon Energy has provided Actual Information in relation to variables in Table 4.2.1 for all categories associated with Meter Type 6 for the period 2018-19.

Ergon Energy has used Actual Information, in accordance with the AER's definition, for the following variables in Table 4.2.2 - Cost Metrics (volumes):

- Meter Purchases
- Meter Testing
- Meter Investigation
- Scheduled Meter Reading
- Special Meter Reading
- New Meter Installation
- Meter Replacements
- Meter Maintenance

Ergon Energy has used Actual Information, in accordance with the AER's definition, for the following variables in Table 4.2.2 - Cost Metrics (expenditure):

- Meter Purchases
- Meter Testing
- Meter Investigation
- Scheduled Meter Reading

- Special Meter Reading
- Meter Replacements
- Meter Maintenance

16.7 Explanatory Notes

Not applicable.

17 BOP – 4.2 Metering (Estimate)

17.1 Scope of BOP

17.1.1 Table 4.2.2 - Cost Metrics

17.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy notes that it does not have regulated metering services relating to meter categories Type 4, Type 5 nor Type 7. Type 5 metering is not permitted in Queensland as per the National Metrology Procedure Part A. Type 7 metering is contestable work and has been excluded. i.e. watchman lights. Ergon Energy has identified this in the basis of preparation. Accordingly, metrics have been populated as 'zeroes' in this regard.

Ergon Energy has prepared the information provided in Template 4.2 - Metering, Table 4.2.2 - Cost Metrics in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Ergon Energy has not distinguished between expenditure for Metering services between Standard and Alternative Control Services when completing Template 4.2, Table 4.2.1. Furthermore, expenditure has not been distinguished between capital expenditure (capex) and operating expenditure (opex).

This was further clarified by the AER in its issues register, where it noted that all items of capex and opex that were necessary to provide the services listed in templates 4.1 to 4.4 were to be included. In this regard, costs have been measured as the direct cost, excluding overheads.

Data has not been reported in relation to metering services which have been classified as contestable. Non-contestable, regulated metering services have been reported by Ergon Energy including work performed by third parties on behalf of Ergon Energy.

Impacts due to introduction of Power of Choice (PoC) on 1st December 2017 are noticeable in some line items where applicable for volumes and expenditure.

Finally, consistent with guidance provided by the AER in its issues register in relation to certain meter services costs, Ergon Energy notes that:

- meter data costs that could be attributable to specific meter reading activities has been reported as part of the cost for the relevant meter reading services category; and
- data processing costs which could not be attributable to a specific activity has been reported in the "other costs (metering)" category.

17.3 Sources

Ergon Energy has used Estimated Information in relation to the following variables the following variables in Table 4.2.2 - Cost Metrics (expenditure):

- New Meter Installation
- Other Metering Expenditure

17.3.1 Methodology

In relation to New Meter Installation expenditure, Ergon Energy has developed an estimate based on the following approach:

All capital costs for Installed Regulated Meters (except Meter Replacement) are recorded against Activity Code C2230. Transactions for this activity are itemised in B-FN-FP-0614 report which is used to select expenditure for new meter installations in POC exempt areas.

Meter Changes / Installations have been evaluated for the Financial Year by comparing MARS meter installation volumes against PEACE PTJ types which provides a total of New Meters Installed for the financial year for the different Installation Activities.

Ergon Energy considers the best estimate has been provided for New Meter Installation expenditure on the basis that:

- No exact figure is available;
- Cost estimates are based on Ellipse and MARS data;
- Average expenditure is expected to provide a good approximation of actual costs;
- Best endeavours have been used to extract values from existing data.

In relation to Other Metering Type 6 Expenditure, Ergon Energy has developed an estimate based on the following approach:

Other Metering expenditure was sourced from Ellipse Reports based on based on Activity Codes, Standard Jobs and Product Code mapping.

- Other Metering Type 6 expenditure consists of the totaling of the remaining opex and capex expenditure.
- Other Metering Type 6 capex subtotal was calculated by subtracting the total of capex expenditure (New Meter Installation and Meter Replacement) from the General Ledger capex total.

- Other Metering Type 6 opex subtotal is summarised from the CA RIN Index for relevant Standard Jobs and Product Codes related to all Other Metering Activities.
- The Other Metering Type 6 Capex and Other Metering Type 6 Opex subtotals were added to provide a total Other Metering Type 6 expenditure.

17.4 Assumptions

Refer to Section 17.5 Estimated Information for assumptions applied.

17.5 Estimated or Actual Information

Reasons as to why it was not possible to provide Actual Information, and why an estimate is required in relation to each of the variables is noted below:

- New Meter Installation expenditure is included in the New Meter activity which includes the costs of New Metering Installations and meters installed as part of Additions and Alterations.
- Other Metering expenditure is based on all other expenditure not categorised. With New Meter Installations expenditure being an estimate, this has resulted in the Other Metering value for expenditure also being an estimate.

17.6 Explanatory Notes

Not applicable.

18 BOP - 4.3 Fee-Based Services

18.1 Scope of BOP

18.1.1 Table 4.3.1 - Cost Metrics for Fee-Based Services

18.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 4.3, Table 4.3.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

As advised by the AER, Ergon Energy has not had regard to paragraph 15.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN.

For the purposes of completing Template 4.3, Ergon Energy has reported categories for fee-based services that were listed in its Annual Pricing Proposal encompassing each relevant year taking note of Appendix E, Principles and Requirements, paragraph 15.2 of the AER's RIN. Please note: Fee Based Services with Nil transactions for the year (amount, volume) have been excluded.

However, there are instances where the Pricing Proposal category headings differ slightly to the mandatory categories in the template therefore the following mapping has been applied:

Table 18-1 Fee Based Services Mapping Table

CA RIN Mandatory Category	EECL Pricing Proposal
De-energisation	De-energisation during business hours
De-energisation	De-energisation after business hours
De-energisation	Call out fee for de-energisation during business hours
De-energisation	Call out fee for de-energisations after business hours
Re-energisation	Re-energisation during business hours
Re-energisation	Re-energisation after business hours

Re-energisation	Re-energisation during business hours - after de-energisation for debt
Re-energisation	Call out fee for re-energisation during business hours
Re-energisation	Call out fee for re-energisation after business hours
Re-energisation	Call out fee for re-energisation during business hours - after de-energisation for debt

Relative to requirement 15.2 only fee-based services have been populated in this template. The mandatory category, 'energisation' is a Connection Service classified as a Standard Control Service (not a fee-based or quoted service), therefore has been excluded. Only operating costs have been reported, no capital expenditure (capex) is captured for fee based services.

Furthermore, in meeting requirements of Appendix E, Principles and Requirements paragraph 15.3 of the AER's RIN; the Table below provides a description of each fee based service listed in regulatory template 4.3 including the purpose of each service and the activities which comprise each service.

Costs have been measured as the direct cost, excluding overheads.

18.3 Sources

Actual Information for the variables was sourced from a combination of Ellipse and PEACE Financial and Quantitative Reporting.

18.4 Methodology

The data used to populate the template was extracted from the Ellipse General Ledger and then using the segment of the chart of account established for this purpose the revenue and costs relating to Alternative Control Services (ACS) was identified. The amount of overheads was identified by using the relevant account code and then excluding this amount from direct costs.

PEACE market system closed service orders or Ellipse work orders are then counted to calculate the related volumes depending on the service.

There are limitations in matching expenditure to volumes for services performed, as in some cases, the costs for minor ACS work performed on the same day by the same team has been ultimately captured against one service, not multiple services.

Note: in accordance with Schedule 8 s225, Ergon Energy is unable to charge for disconnection of supply of electricity to premises.

18.5 Assumptions

No assumptions have been applied.

18.6 Estimated or Actual Information

Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 4.3.1.

18.7 Explanatory Notes

The Fee Based Services in the below Table are reflective of all of the categories of Fee Based Services that were listed in Ergon Energy's Annual Pricing Proposal for the 2018-19 year in accordance with Appendix E, Principles and Requirements, paragraph 15.2 of the AER's RIN.

Table 18-2 Fee Based Services

Common and Miscellaneous Services	Purpose / Activities of each service
Application fee - Basic or standard connection	Services associated with assessing an application requesting a connection to be made (or altered) between Ergon Energy's network and the customer's installation, and the preparation of a compliant basic or standard connection offer. Applies to small customers classified as a Standard Asset Customer (SAC), as per Ergon Energy's pricing proposal.
Application fee - Basic or standard connection - Micro-embedded generators	Services associated with assessing a micro-embedded generator application requesting a connection to be made (or altered) between Ergon Energy's network and the customer's installation, and the preparation of a compliant basic or standard connection offer. Applies to micro-embedded generators only (a subset of Standard Asset Customers, as per Ergon Energy's pricing proposal). No technical

	assessment required.
Application fee - Real estate development connection	Services associated with assessing an application requesting a connection to be made between Ergon Energy's network and a real estate developer's installation, and the preparation of a compliant connection offer. Includes works carried out by contractors and/or Ergon Energy.
Protection and Power Quality assessment prior to connection	Evaluation of application protection design for completeness against engineering connection standard. Study of Power Quality issues including Flicker, Harmonics and DC voltage injection.
Temporary connection, not in permanent position - single phase metered	Connection of a single phase supply to a meter location that is not permanent (i.e. short term supply). Excludes work on metering equipment.
Temporary connection, not in permanent position - multi phase metered	Connection of a multi-phase supply to a meter location that is not permanent (i.e. short term supply). Excludes work on metering equipment.
Work on metering equipment for temporary connection, not in permanent position - single phase or multi phase metered	Work on metering equipment undertaken by Ergon Energy to accommodate a temporary connection. Note: this service is only available for non-grid connected areas of our network (isolated feeders and the Mount Isa-Cloncurry supply network).
Supply abolishment during business hours	Retailer requests Ergon Energy to abolish supply at a connection point and decommission a NMI. May be used where a property is to be demolished; supply is no longer required; an alternative connection point is to be used; or a redundant supply is to be removed. Excludes

	decommissioning of metering undertaken by Ergon Energy or an alternative provider.
Decommissioning of metering equipment for supply abolishment	Decommissioning of metering associated with a retailer request to abolish supply at a connection point. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
De-energisation during business hours	Retailer requests de-energisation of the customer's premises during business hours: • where the de-energisation can be performed (e.g. pole, pillar or meter) • Main switch sticker
Re-energisation during business hours	Retailer requests re-energisation of customer's premises during business hours: • after a physical disconnection and premises requires a visual examination • following a main switch sticker
Re-energisation during business hours - after de-energisation for debt	Retailer requests re-energisation of customer's premises during business hours where the customer was previously de-energised for non-payment of their electricity account.
Visual examination during business hours for remote re-energisation - long rural/isolated feeders	Retailer or Metering Co-ordinator requests visual examination during business hours, prior to performing a remote re-energisation.
Visual examination during business hours for remote re-energisation - after de-energisation for debt - urban/short rural feeders	Retailer or Metering Co-ordinator requests visual examination during business hours, prior to performing a remote re-energisation. Applies where the customer was previously de-energised

	for non-payment of their electricity account.
Accreditation of alternative service providers - real estate developments	Accreditation of service providers that meet competency criteria. Applies to real estate developments.
Install replacement meter (Type 5 and 6) – Single phase	Installation and provision during business hours of a single phase replacement meter, where allowed by regulation. Note: this service is only available in non-grid connected areas of our network (isolated feeders and feeders in Mount Isa-Cloncurry supply network).
Install replacement meter (Type 5 and 6) – Dual element	Installation and provision during business hours of a dual element replacement meter, where allowed by regulation. Note: this service is only available in non-grid connected areas of our network (isolated feeders and feeders in Mount Isa-Cloncurry supply network).
Install replacement meter (Type 5 and 6) – Polyphase	Installation and provision during business hours of a polyphase replacement meter, where allowed by regulation. Note: this service is only available in non-grid connected areas of our network (isolated feeders and feeders in Mount Isa-Cloncurry supply network).
Install replacement meter (CT)	Installation and provision during business hours of a CT replacement meter, where allowed by regulation. Note: this service is only available in non-grid connected areas of our network (isolated feeders and feeders in Mount Isa-Cloncurry supply

	network).

19 BOP - 4.4 Quoted Services

19.1 Scope of BOP

19.1.1 Table 4.4.1 - Cost Metrics for Quoted Services

19.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 4.4, Table 4.4.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

As advised by the AER, Ergon Energy has not had regard to paragraph 15.1 of the AER's Principles and Requirements in Appendix E, which is noted as not being relevant to preparation of a response to a non-Reset RIN.

For the purposes of completing Template 4.4, Ergon Energy has reported categories of Quoted Services that were listed in its Annual Pricing Proposal taking note of Appendix E, Principles and Requirements, paragraph 15.2 of the AER's RIN.

It should be noted that the categories applying to the 2018-19 data have changed in accordance with Ergon Energy's final determination for the 2015-20 regulatory control period. As a result, care should be taken when comparing any time series data in relation Quoted Services expenditure and volumes.

In meeting requirements of Appendix E, Principles and Requirements paragraph 15.3 of the AER's RIN, The Table below provides a description of each Quoted Service listed in regulatory template 4.4 including the purpose of each service and the activities which comprise each service. Quoted Services with Nil transactions for the year (amount, volume) have been excluded.

Costs have been measured as the direct cost, excluding overheads.

Furthermore, the AER noted at Issue 58 in the Issues Register that recoverable work projects (including all costs associated with customer requested capital works for which the prime purpose is to satisfy a customer requirement other than new or increased supply) was to be included as quoted services and hence captured in template 4.4. These projects have also been included in connections works under template 2.5.

19.3 Sources

Actual Information for the variables was sourced from Ergon Energy's Ellipse and PEACE Financial and Quantitative Reporting.

19.4 Methodology

In order to obtain the information, it was necessary for Ergon Energy to combine the total count of services from the two source systems being Ellipse and PEACE for the product codes applicable to quoted based services for the required years.

The data used to populate the template was extracted from the Ellipse General Ledger and then using the segment of the chart of account established for this purpose the revenue and costs relating to Alternative Control Services (ACS) was identified. For Large Customer Connections (LCC), the large customer contribution and gifted asset activities are identified and summarised by works requests. The amount of overheads was identified by using the relevant account code and then excluding this amount from direct costs.

PEACE market system closed service orders or Ellipse work orders and Ellipse works requests are then counted to calculate the related volumes depending on the service.

There are limitations in matching expenditure to volumes for services performed, as in some cases, the costs for minor ACS work performed on the same day by the same team has been ultimately captured against one service, not multiple services.

19.5 Assumptions

No assumptions have been applied.

19.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER's definition, for all variables in Table all variables in Table 4.4.1

19.7 Explanatory Notes

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

Table 19-1 Quoted Services description

Quoted Services	Purpose and Activities of Service
Accreditation of alternative service providers - major customer connections	Accreditation of service providers that meet competency criteria. Applies to major customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or Embedded Generator (EG) as per Ergon Energy's pricing proposal.
Aerial markers	Installation of aerial markers (or Powerlink Hazard Identifiers) on service lines
Application fee - Negotiated - Major customer connection	Services associated with assessing a major customer connection application requesting a connection to be made (or altered) between Ergon Energy's network and the customer's installation, and the costs associated with negotiating and preparing a compliant negotiated connection offer. Applies to major customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or Embedded Generator (EG), as per Ergon Energy's pricing proposal.
Application fee - Negotiated connection	Services associated with assessing an application requesting a connection to be made (or altered) between Ergon Energy's network and the customer's installation, and the costs associated with negotiating and preparing a negotiated connection offer. Applies to small customers classified as a Standard Asset Customer (SAC), as per Ergon Energy's pricing proposal, with the exception of micro-embedded generators.
Application fee - Negotiated connection - Micro-embedded generators	Services associated with assessing a micro-embedded generator application requesting a connection to be made (or altered) between Ergon Energy's network and the customer's installation, and the costs associated with negotiating and preparing a negotiated connection offer. Applies to micro-embedded generators only (a subset of SAC, as per Ergon Energy's pricing proposal).

Approval of third party design - major customer connections	Review, inspection and auditing of design carried out by an alternative service provider prior to energisation. Applies to major customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or Embedded Generator (EG) as per Ergon Energy's pricing proposal.
Approval of third party design - real estate developments	Review, inspection and auditing of design carried out by an alternative service provider prior to energisation. Applies to real estate developments.
Approval of third party materials	Certification of non-approved materials (i.e. approval of non-approved materials to be used on Ergon Energy's network).
Assessment for Non-Exporting embedded generator applications	Services associated with assessing a generator on a customer's installation which will not be exporting into the distribution system. Includes costs associated with preparing a Consent Agreement.
Call out fee for de-energisations after business hours	Travel time to perform a de-energisation after business hours requested by a retailer, and the service is unable to be performed due to customer/retailer fault.
Call out fee for meter test	Travel time to perform a meter test requested by a retailer, and the service is unable to be completed due to customer/retailer fault.
Call out fee for re-energisations after business hours	Travel time to perform a re-energisation or visual examination after business hours requested by a retailer, and the service is unable to be performed due to customer/retailer fault.
Call out fee for special meter read	Travel time to perform a special meter read requested by a retailer, and the service is unable to be completed due to customer/retailer fault. Does not include final meter reads.
Carrying out planning studies and analysis relating to connection applications	Services associated with carrying out additional planning studies and analysis on the distribution system which are reasonably required to assess a small customer or real estate development connection application. Excludes planning studies and analysis that would otherwise be required for distributor purposes or for the efficient management of the

	shared network. Applies to small customers classified as a Standard Asset Customer, as per Ergon Energy's pricing proposal (including micro-embedded generators), and real estate developers.
Change load control relay channel	Change load control relay channel at retailer, customer or other third party request that is not part of initial load control installation, nor part of standard asset maintenance or replacement.
Change tariff	Request to reprogram meter due to change in tariff (including adding or removing a tariff) and/or time of use setting (except for controlled load timing changes. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises. Where a new or replacement meter is required to support a change in tariff, Ergon Energy is only able to undertake this work in non-grid connected areas of our network (Isolated feeders and feeders in Mount Isa-Cloncurry supply network).
Change time switch	Change to time switch setting
Commissioning and energisation of major customer connections	Includes: • inspection and testing of connection assets prior to physical connection to the network • physical connection and energisation of electricity equipment to allow conveyance of electricity • administration services involved in reconciling the financials of a connection project, and processing and finalising network information and contracts in relation to a connection • generation required (if any) to supply existing customers while equipment is de-energised to allow testing and commissioning Applies to major customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or Embedded

	Generator (EG) as per Ergon Energy's pricing proposal.
Commissioning and energisation of real estate development connections	Includes: • inspection and testing prior to physical connection to the network • physical connection and energisation of electricity equipment to allow conveyance of electricity • administration services involved in reconciling the financials of a connection project, and processing and finalising network information and contracts in relation to a connection • generation required (if any) to supply existing customers while equipment is de-energised to allow testing and commissioning
Construction audit - major customer connections	Review, inspection and auditing of construction works carried out by an alternative service provider prior to energisation. Applies to major customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or Embedded Generator (EG) as per Ergon Energy's pricing proposal.
Construction audit - real estate developments	Review, inspection and auditing of construction works carried out by an alternative service provider prior to energisation. Applies to real estate developments.
Customer ,retailer or third party requested appointments	Works initiated by a customer, retailer or third party which are not covered by another service and are not required for the efficient management of the network, or to satisfy distributor purposes or obligations. Includes, but is not limited to: • restoration of supply due to customer action • re-test at customer's installation (i.e. customer has submitted Form A and the Retailer has issued a Service Order Request, but installation fails test and cannot be connected, requiring a re-test of the installation) • safety observer

	• tree trimming • switching • cable bundling • checking pump size for tariff eligibility.
Customer build, own and operate consultation services	Provision of advice, design and specification on request to an applicant considering a build-own-operate asset ownership option for connection assets.
De-energisation after business hours	Retailer requests de-energisation of the customer's premises after business hours: • where the de-energisation can be performed (e.g. pole, pillar or meter). • Main switch sticker
Design and construction for real estate developments	Detailed design work and construction for a real estate development connection after a connection offer has been made. Includes work associated with augmentation to the shared network which is directly attributable to the establishment or alteration of the real estate development connection
Design and construction of connection assets for major customers	Detailed design work and construction of connection assets after a connection offer has been made. Applies to major customers classified as an Individually Calculated Customer (ICC), Connection Asset Customer (CAC) or Embedded Generator (EG) as per Ergon Energy's pricing proposal.
Detailed enquiry response fee - embedded generation	Costs associated with preparing a detailed enquiry response pursuant to Chapter 5 of the NER. Applies to any embedded generation connection applicant that submits an enquiry under the connection process set out in Chapter 5 of the NER and seeks a detailed enquiry response.

Exchange meter	Like for like meter exchange on request, unless not allowed by regulation Note: this service is only available for non-grid connected areas of our network (isolated feeders and the Mount Isa-Cloncurry supply network)
Feasibility and concept scoping, including planning and design, for major customer connections	Detailed design and advice for major customer connections for the selected (preferred) connection option. This includes shared network planning and design works incurred during the feasibility and concept scoping phases (i.e. before the connection offer has been accepted) (where applicable).
HV Service line drop and replace	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - Isolate and earth
Install metering related load control	Installation of customer load control initiated and managed via the meter Note: where a new or replacement meter is deemed to be required, Ergon Energy is only able to undertake this work in non-grid connected areas of our network (Isolated feeders and Mount Isa-Cloncurry supply network)
Install new or replacement meter - after hours	Installation and provision after hours of a Type 5 and 6 or CT meter on or after 1 July 2015. All feeder types. Note: this service is only available in non-grid connected areas of our network (isolated feeders and feeders in Mount Isa-Cloncurry supply network).
LV Service line drop and replace - physical dismantling	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (e.g. overhead service dropped).
Meter inspection and investigation on request	A request to conduct a site review of the state of the customer's metering installation without physically testing the metering equipment. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Meter re-seal	Where the customer has caused the meter to need re-sealing (e.g. by having electrical work done on site)

	Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Meter test	Customer requested meter accuracy testing of Ergon Energy whole current Type 5 and 6 meter. Also includes meter tests by Ergon Energy for Ergon Energy meters attached to a CT. Only available where meter installed and operational. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Metering alteration	Meter is being relocated or meter wiring altered and requires Ergon Energy to visit site to verify the integrity of the metering equipment. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Metering Co-ordinator requested appointments	Works initiated by a Metering Co-ordinator, which are not covered by another service and are not required for the efficient management of the network, or to satisfy distributor purposes or obligations. Includes but is not limited to: • temporary isolation of power to allow an alternative provider to work on their metering installation • restoration of supply due to fault with another provider's metering installation
Move point of attachment - single/multi phase	De-energisation, followed by physical dismantling then reattachment of service and re-energisation. Excludes work on metering equipment (if required).
Non-standard network data requests	Customer requests provision of electricity network data requiring customised investigation, analysis or technical input (e.g. requests for pole assess information and zone substation data)
Pre-connection site inspection	Site inspection in order to determine nature of connection being sought

Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates	Initial specification and design outline for major customer connections. Includes general evaluation and advice on asset ownership options, indicative estimates of viable connection options, and recommendation on the most suitable option.
Protection and Power Quality assessment after connection	Investigation into Power Quality issues including Flicker, Harmonics and DC voltage injection.
Provision of connection services above minimum requirements	Customer requests increase in reliability or quality of supply beyond the standard, and/or above minimum regulatory requirements (e.g. reserve feeder). Excludes work on metering equipment (if required)
Provision of services for approved unmetered supplies	Provision of services, other than standard connection, for approved unmetered equipment, public telephones, traffic lights and public BBQs. Includes attendance on site to verify a load change, following a customer request to increase or decrease the load of a network connected unmetered supply device.
Provision of site-specific connection information and advice	Provision of site-specific connection advice, data and/or information on request (during the connection enquiry and/or connection application stage only). For example: • advice on project feasibility • advice on whether augmentation would likely be required • capacity information, including specific network capacity • load profiles for load flow studies • requests to review reports and designs prepared by external consultants, prior to lodgement of connection application

	• additional or more detailed specification and design options. Excludes information provided in planning reports/studies and project scopes.
Re-arrange connection assets at customer's request	Removal, relocation or rearrangement of connection assets at customer request. Excludes work on metering equipment (if required).
Rectification of illegal connections or damage to overhead or underground service cables	Repair works to re-establish a safe and legal connection due to customer or third party action. Excludes work on metering equipment (if required)
Re-energisation after business hours	Retailer requests re-energisation of a customer's premises after business hours: • after a physical disconnection and premises requires a visual examination • following a main switch sticker • where the customer was previously de-energised for non-payment of their electricity account
Removal of a meter (Type 5 & 6)	Removal of a meter on request when an existing Type 5 or 6 meter remains installed at the premises. Includes – remove meter and re-commission installation; no re-wiring required. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Removal of load control device	Remove load control relay or time clock on request
Removal of network constraint for embedded	Augmenting the network to remove a constraint faced by an embedded generator

generator	
Removal/rearrangement of network assets	Removal, relocation or rearrangement of network assets (other than connection assets) at customer request, that would not otherwise have been required for the efficient management of the network.
Removal/rearrangement of public lighting assets	Relocation, rearrangement and removal of existing public light assets and energy efficient retrofit
Reprogram card meters	Attend and reprogram card meters to reflect retail tariffs, outside scheduled visit Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Services provided in relation to a Retailer of Last Resort (ROLR) event	Services Ergon Energy provides when a ROLR event occurs
Special meter read	Off-cycle meter read, during business hours. Does not include final meter reads which are included in Default Metering Services. Note: this service is only available where Ergon Energy is the default Metering Co-ordinator or Responsible Person for the premises.
Supply enhancement	For example, an upgrade from single phase to multi phase and/or increase capacity. Applies to underground and overhead service upgrades. Excludes work on metering equipment (if required)
Temporary de-energisation - no dismantling	Temporary de-energisation and re-energisation of supply at the service fuse to allow customer or contractor to work close - no dismantling of service required (i.e. no service line drop).
Tender process	Applies where Ergon Energy conducts a tender process on behalf of a connection applicant to procure connection services that can be provided by a third party, or where the connection applicant conducts a tender process and requires assistance from Ergon Energy

Tiger tails	Installation of covers on service lines
Type 5 to 7 non-standard metering services	Provision of Type 5 to 7 metering services above minimum requirements, unless not allowed by regulation. For example: • provision, installation and maintenance of meters above minimum requirements (i.e. installation of a non-standard meter above minimum regulatory requirements on request) • provision of metering data above minimum requirements (such as urgent delivery, summarisation of metering data, historical metering data prior to the previous 2 years etc.) • provision of time of use metering data (provision of half hourly data on request if available. Collection and processing of probe read data from accumulation read interval capable meters on a one off basis.) • provision of energy pulsing output for a customer • interface to building management system Note: where a new or replacement meter is deemed to be required, Ergon Energy is only able to undertake this work in non-grid connected areas of our network (Isolated feeders and Mount Isa-Cloncurry supply network)
Upgrade from overhead to underground service	Requests to convert an existing overhead service to an underground service. Excludes work on metering equipment (if required)
Visual examination after business hours for remote re-energisation	Retailer or Metering Co-ordinator requests visual examination during business hours, prior to performing a remote re-energisation. Applies all instances, including where the customer was previously de-energised for non-payment of their electricity account.
Witness testing	Witnessing of testing carried out at the customer's installation by the connection applicant where reasonably required or requested (e.g. as the result of the introduction of a parallel generator on a customer's installation)
Work on metering equipment for a post	Work on metering equipment undertaken by Ergon Energy in conjunction with a post connection quoted service. Only applies where this work is not

connection service, not covered by another metering service.	covered by another metering service. Note: this service is only available where Ergon Energy is the Default Metering Co-ordinator or Responsible Person for the premises.

20 BOP - 5.2 Asset Age Profile

20.1 Scope of BOP

20.1.1 Table 5.2.1 - Asset Age Profile

20.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Ergon Energy has considered and complied with clarifications provided by the AER on 2 July 2015 on issues related to template 5.2.

20.3 Sources

Ergon Energy has prepared the information provided in Template 5.2, Table 5.2.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Ergon Energy has considered and compiled with clarifications provided by the AER on 2 July 2016 on issues related to template 5.2.

20.4 Mean Life and Standard Deviation

Ergon Energy has developed the estimated mean life for the assets based on general industry life expectations, manufacturer's specification and operational experience with the assets.

Economic Life (standard deviation) was approximated by the square root of the mean in accordance with the AER guidance.

20.5 Age Profiles

The data for the 5.2.1 age profiles comes from numerous systems.

- Ergon Energy Ellipse database. This system is the Ergon Energy corporate ERP and holds the main Ergon Energy asset register, work order information, project information, financial information, etc

Ergon Energy Smallworld replicated spatial database. This database is replicated from the Smallworld geographic information (GIS) electrical data store. This database holds the electrical spatial and connectivity information and is the only place that linear assets (conductors) are modelled.

20.6 Methodology

Mean Life and Standard Deviation

Ergon Energy has developed the estimated mean life for the assets based on general industry life expectations, manufacturer's specification and operational experience with the assets.

Economic Life (standard deviation) was approximated by the square root of the mean in accordance with the AER guidance

Age Profile

Poles

In relation to Age Profile, Ergon Energy has developed an estimate based on the following approach:

- In the absence of specific records, Ergon Energy has attempted to infer Year of installation from related or nearby asset data records. In continued absence of reasonable results, Ergon Energy has attempted to infer near-YOM from records about the manufacturing and available records from Manufacturers. In continued absence of reasonable results, Ergon Energy has used more tenuous relationships to determine an age profile as it is understood that an important end purpose of the RIN Template 5.2.1 data is to use it to populate the AER's REPEX model. Similar age inference processes were used during the development of Ergon Energy's internal condition based refurbishment maintenance (CBRM) modelling.
- In relation to Age Profile, Ergon Energy has developed an estimate for age by using the following in order of priority:
    - obtain previous calculated age from Ellipse
    - obtain the treatment year from Ellipse
    - obtain the replacement work order year from Ellipse work orders
    - find date installed from ellipse
    - use the CBRM year, Ergon Energy has attempted to infer near-YOM from records about the manufacturing and available records from manufacturers
    - If the pole is a natural distribute the poles from 1950-1964. These poles do not have a nameplate or any age information, but we only used these poles in these years

- Find 5 closest connected poles. Obtain the treatment year or pole install year (in order of priority) of each of those poles and then use the minimum age across the close connected poles.

If none of the above return an age, then we use a series of fall back's depending on pole construction based on when we used the different types of poles.

- Wood - 1963 to current year
- Steel – 1990 to current year
- Concrete – 1980 to current

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

- That similar nearby assets will have been installed at approximately the same time
- For poles that are still unknown that on average the same number of poles are installed (of the same type) each year.

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that:

- A hierarchy of logic has been used so that the best possible value for the Age Profile was chosen, including basing the age on surrounding equipment and finally at the lowest level distributing the years across the period that the poles were known to be used.
- Ergon Energy uses the Field Mobile Computing (FMC) to provide Pole Maintenance data to the cooperate system. There are delay between the installation date and inspection date. This causes distortion in the age profile of the newly installed pole data. This distortion will be cleared after the maintenance inspection.

Pole Staking

In relation to Age Profile, Ergon Energy has developed an estimate based on the following approach:

- Ergon Energy has used Works Order information to obtain age profile back to 2002, beyond this the population was spread between 1985 (date of commencement of pole staking) and 2002. Known duplicates generated during a system conversion in 2004 and 2005 have been manually removed.

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

- There were no staked poles before 1985
- Closed works orders equate to installed pole stakes

- Staked poles are NOT counted as a unique asset, they are counted under the poles category, including these in pole counts will lead to counting duplicates and totals will then not equal the totals in Table 2.8.1

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that:

- For staking of wooden poles. Work Orders were used to estimate the number of poles back to 2002, earlier results have been manually populated to include the total number of poles

Overhead Conductors and Underground Cables

Ergon Energy considers the following the best estimate has been provided for the age profile on the basis that:

- A hierarchy of logic has been used so that the best possible value for the Age Profile was chosen, including basing the age on surrounding equipment, testing ages against known periods that different constructions were made and using nominal ages for when no other information was known. Assets that still had an unknown age were distributed in their category in the existing profile.

Overhead Conductor Age

In relation to overhead conductor age, Ergon Energy has developed an estimate based on the following approach:

- Obtain the latest date the line was installed, upgraded or replaced in a Smallworld design.
- Obtain the earliest pole treatment year of poles the line is mounted on. If this date is within the date range specified for the construction in the CBRM QESI inferred date table, use this date.
- If the conductor is mounted on “Natural Round” poles and 1955 is within the date range specified for the construction in the CBRM QESI inferred date table, use 1955.
- If the conductor is in NQ and its construction is one of ('200','203','204','205','207','208','211','212','213','214') use 1985.
- If the construction has a numeric value use the nominal year from CBRM QESI inferred date Table for the construction.
- If the construction is non-numeric, use the alternative nominal year from CBRM QESI inferred date Table for the construction.
- Date is unknown.

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

- The energisation processes all installed new conductor.
- Conductors for which no age was able to be determined, were added to the amounts for aged conductors, in the same proportion as the aged conductor to the total age for each year.
- Ergon Energy inferred the natural round pole by assigning flat line age profile year between 1949/50 – 1961/62 for the following voltage categories.
- < = 1 kV; Wood
- > 1 kV & < = 11 kV; Wood
- < 11 kV & < = 22 kV; Wood
- Therefore, a conductor may be mounted on natural round pole with assigned age between 1949 and 1962. The conductor inferring rule would assign same age of the oldest pole on the feeder. This gave a high volume of asset in the older range and less volume in the younger range. Due to this reason, Ergon Energy change the overhead conductor age profile between 1949/50 and 1961/62 by averaging the total length of conductor voltages in following categories and flat lined the age profile similar to natural round pole age profile.
- < = 1 kV
- > 1 kV & < = 11 kV
- < 11 kV & < = 22 kV ; Single-Phase
- < 11 kV & < = 22 kV ; Multiple-Phase

Underground Conductor Age

In relation to underground conductor age, Ergon Energy has developed an estimate based on the following approach:

- Obtain the installation recorded against the cable in GIS.
- Obtain the latest date the cable was installed, upgraded or replaced in a Smallworld design.
- Traverse the network downstream from the cable and determine the date as follows

Installation date of downstream cable.

Age of downstream switches.

Age of downstream transformers.

Age of supporting poles.

Age of ground-mounted substation or pillar.

- Nominal year assigned to the QESI code associated with the cable's construction.
- Date is unknown

RIN Template 5.2.1 is populated from Ergon Energy's GIS system for Subtransmission, Distribution and LV underground cable. The age profile has been inferred from connected assets, downstream transformers and switchgear and installation age ranges for cable types.

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

- Cables for which no age was able to be determined were added to the amounts for aged cables, in the same proportion as the aged cable to the total age for each year.

Service Lines

In relation to service lines age, Ergon Energy has developed an estimate based on the following approach:

For each service point a service line is assumed:

- If a service point is directly related through an overhead wire of less than 50m.to a pole, a service line is assigned the inferred age of the pole.
- For non-directly related service points the nearest structure (pole, pit, pillar or gms site) to the service point is found. If the nearest structure is a pole and within 50m, a service line is assigned the inferred age for that pole.

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that:

- LV lines are not separately represented in the data systems and a service line will not generally be longer than 50m.
- A best effort has been made to identify premise's that would be connected by overhead service lines whose data has not been captured in our systems.
- The age was determined by the most reliable related nearby asset (poles).

Transformers by Mounting Type and Operating Voltage, Voltage Transformers and Current Transformers

In relation to Age Profile Ergon Energy has developed an estimate based on the following approach:

The year of installation is determined by following this hierarchy until an answer is found:

- COMM-DATE (Commissioning Date) nameplate against the asset in Ellipse.
- YOM (Year of Manufacture) nameplate against the asset in Ellipse.
- date_installed attribute of the asset in Smallworld.
- date_installed attribute of the associated substation in Smallworld.
- treatment year nameplate against the pole the asset is mounted on
- latest YOM or COMM-DATE nameplates against equipment at the GMS site the asset is mounted on.
- earliest premise status date for customers associated with the asset substation.

Where the above logic results in blank or a non-sensible value those assets are distributed to the same shape distribution as the assets with a real or inferred age. Note, Age Profile For substation transformers >22kV (row 96 on) is predominantly actual data as only small gaps in age data exist.

In developing this estimate, Ergon Energy has made the assumption that customers are associated to the asset.

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that:

- A hierarchy of rules is used so that the best sources are interrogated first working down to the more tenuous connections

Voltage transformers and current transformers are specific types of transformers that are removed from the transformers by mounting type and separated into their own categories.

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that:

- A hierarchy of logic has been used so that the best possible value for the Age Profile was chosen, including basing the age on surrounding equipment and finally at the lowest level distributing the years across the period that the poles were known to be used.

Switchgear by Voltage and Function - Fuses

The age profile has been estimated using the assumption that each distribution transformer has one set of HV and one set of LV fuses up until 2013/14. From 2017-18 onwards, only LV fuses have been reported against the "< = 11 kV FUSE" category as per AER response of 02/07/2016; "the omission of a category for 'fuses >11kV' is intentional. AER staff note the definition of 'switch' includes fuses at higher voltages. Because of the high number of fuses at the <=11 kV category, these are asked for separately. All other categories have been rationalised for each Asset Group with a single 'other' available for those categories not listed."

Switchgear by Voltage and Function - Circuit Breakers and Switches

Switch age is determined in the following order

- The COMM-DATE (Commissioning Date) nameplate against the switch physical in Ellipse.
- The YOM (Year of Manufacture) nameplate against the switch physical in Ellipse.
- The year the latest design, containing an Install, Upgrade or Replace action against the switch, was energised.
- The age of the site on which the switch is mounted, determined as follows:
  - For poles, obtain the inferred age for the pole using the logic described in the pole age profile above.
  - For GMS sites, obtain the latest Year of Manufacture or Commissioning Date nameplate values for equipment mounted on the site.
  - For zone substation sites, obtain the default CBRM date for equipment located at the zone substation.
- Where the above logic results in blank or a non-sensible value those assets are distributed to the same shape distribution as the assets with a real or inferred age.
- The HV fuses age profile has been estimated using the assumption that each distribution transformer has one set of HV and one set of LV fuses. From 2017-18 onwards, the HV fuses have been reported in the group "<= 11 SWITCH" category as per AER response of 02/07/2016; "the omission of a category for 'fuses >11kV' is intentional. AER staff note the definition of 'switch' includes fuses at higher voltages. Because of the high number of fuses at the <=11 kV category, these are asked for separately. All other categories have been rationalised for each Asset Group with a single 'other' available for those categories not listed."

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that: a hierarchy of logic has been used so that the best possible value for the Age Profile was chosen, including basing the age on surrounding equipment and finally at the lowest level distributing the years across the period that the poles were known to be used.

SCADA Network Control Master Stations

Ergon Energy asset information in this category is based on actual replacement data and any projects that installed assets within this time period.

SCADA Field Devices

Ergon Energy SCADA field devices include asset information in the following categories:

- Substation & other Remote Terminal Units
- Local Master Station (Human Machine Interface, local control interface)

Asset Information in these categories are obtained from the following sources:

- Manual record keeping files
- RTU and HMI Configuration Files
- Project data where RTU or HMI units were cross referenced as ordered and fulfilled from the warehouse, and an RTU/HMI configuration was built for the project.

AFLC Devices

Ergon Energy AFLC device information is gathered from completed projects, cross-referenced by commissioning into the Ergon Energy Network Control Master Station.

Protection Systems, Field Devices and Local Wiring Assets

Ergon Energy has obtained estimated asset information for the 2018-19 financial year utilising the following methodology:

Protection Relays

Obtained an actual asset population count:

- Ergon Energy has performed a comprehensive site audit and is continuously correcting the protection relay asset data in Ellipse. The asset age profile is sourced primarily from the corrected Ellipse data with supplemental information taken from PDS records, the IPS protection database and substation construction records.

- Year of Manufacture has been determined using name plate data where available. The relay commissioning date, first setting date and purchasing history has also been used as a proxy where nameplate data was unavailable.
- Where the relay age could not be determined, the average relay age at each substation location has been imputed.
- Where no other substation age data was available, the mean age for each relay type (Electro Mechanical, Analog or Digital) was used.
- The protection relay age profile includes Auxiliary (AUX) relays e.g. Timers, Multi trips, Flags etc.
- All information sources are cross-referenced and filtered to ensure individual asset counts, identification of Ergon Energy asset ownership/maintenance, and determination of assets that are operational/in-service.

Communications and local wiring assets

As we have not completed the updating of our base data in the corporate systems, based on expenditure for financial year 2018-19 we have reported installations calculated by Telecommunications Project Managers & Return To Service (RTS Project) installations. Replacements for financial year 2018-19 have been aligned manually with assets from previous financial years and removed accordingly.

In relation to Age Profile (2018-19), Ergon Energy developed the following estimation methodology:

- Report volumes against the RTS project through the Business Objects report assuming one asset replacement per capitalisation line.
- Split the lines between the AER Categories to generate the RTS replacement figure.
- Consult with Telecommunications Project Managers to allocate estimated asset replacements per line for the Telecommunications Capital Program of Works. Allocate these assets across the AER Categories.
- Combine both the RTS and Capital Program of Works figures and apply this to financial year 2018-19 for installed assets.
- Make an assumption based on the technology of the assets replaced and SME advice in financial year 2018-19 of where to reduce the asset volume in previous years.

Capacitor Banks and Static Var Compensators

The year of manufacture or installation is determined by following this hierarchy until an answer is found:

- YOM (Year of Manufacture) nameplate against the asset in Ellipse.
- COMM-DATE (Commissioning Date) nameplate against the asset in Ellipse.

Ergon Energy considers that the best estimate has been provided for Age Profile on the basis that:

- A hierarchy of rules is used so that the best sources are interrogated first working down to the more tenuous connections.

20.7 Assumptions

Refer to Section 20.8 Estimated or Actual Information for assumptions applied.

20.8 Estimated or Actual Information

Age Profile

Ergon Energy has provided Estimated Information in relation to the following variables, for all asset categories in the asset groups.

It was not possible to provide Actual Information in relation to age profiles for all asset categories within the poles asset group thus all data is declared as estimated. As many other categories use pole age those groups are all estimated.

- Natural poles manufactured pre mid 1960s were not fitted with an identification discand furthermore a large data gap exists for around 20% of poles which have lost their disc or have no disc.
- Wood poles (both not reinforced and reinforced) were installed from 1964 to the present.
- Concrete/Steel Poles were installed from 1980 to the present in substantial quantities.
- Steel streetlight poles, were installed from 1990 to the present. This is the period of time for which installation of underground cable increased and therefore so too did the installation of streetlights on dedicated poles.

Protection Relay Assets

It was not possible to provide actual age/year of manufacture information for some protection relay assets due to incomplete data. Approximately 20% of protection relay age data has been imputed using the available dataset.

20.9 Explanatory Notes

Not applicable.

21 BOP - 5.3 MD Network Level

21.1 Scope of BOP

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

21.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Ergon Energy has also provided data in relation to Embedded Generation, Weather Corrected Network Coincident Maximum Demand (for both 10% POE and 50% POE). These cells were shaded orange allowing for 'blacking out' had such information was not collected. The raw maximum demand used for weather correction is adjusted demand.

Embedded generation taken into account at the system level includes scheduled and semi-scheduled generation, and non-scheduled generation where it is equipped with dedicated 30 minute interval metering.

Ergon Energy has prepared the information provided in Template 5.3, Table 5.3.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

21.3 Sources

Actual Information for the variables was sourced from Network Operational Data Warehouse (NODW) previously the variables were stored in the Statistical Metering Database (SMDB). The Network Element Time Series Metering Tool (NETS) accesses the aggregates and stores load information on network assets.

Ergon Energy maintains a series of secure, managed databases known as the NODW that contains historic demand and weather (sourced from the Bureau of Meteorology data). A full version control of the metered data is maintained within NODW and the database is regularly backed-up. Access to the environment is secure and provided only to those persons who require access in order to conduct and manage the load forecasting process, and planning studies, with any changes to the datasets tracked and recorded.

The database is constantly being fed new demand data from a variety of sources including Australian Energy Market Operator (*AEMO*) accredited Meter Data Agents (MDA) for all *NEM* meter data file formatted (MDFF) data for Transmission *Connection* Points (and hence Ergon Energy System Total Demand).

21.4 Methodology

Relative to the information provided for variables in the Table 5.3.1, it was necessary for Ergon Energy to apply the following methodologies and assumptions:

- ***RAW NETWORK COINCIDENT*** **(Native)** Maximum demand obtained from NETS/NODW.
- ***DATE MD OCCURRED*** as extracted from the NETS/NODW aligned with native maximum peak.
- ***HALF HOUR TIME PERIOD MD OCCURRED*** was read from the NETS/NODW, as being the same as the National Electricity Rules (NER) defined “trading interval”. The value reported for this variable is the 30 minute period ending on the hour or on the half hour over which the native maximum demand was recorded. The interval is identified by the *time* at which it ends.
- ***WINTER/SUMMER PEAKING*** data reported aligns with Ergon Energy’s own network demand forecasting cycles, under which Summer Peak is considered to occur in the period 1 October to 31 March inclusive while Winter Peak is considered to occur in the period 1 April to 30 September inclusive. This does not correspond with the form of the definition of a regulatory year due the seasonal nature of customer demand for energy on the network assets. For clarity, Ergon Energy forecasts with the latest available recorded annual maximum demands which are derived from measurements over the 12 month period ending summer. That is to say, for example, for the purpose of forecasting zone substation maximum demand, 201819- is the 12 month period ending 01/04/2019 00:00, of which winter MDs are recorded during period 01/04/2018 00:30 - 01/10/2018 00:00 and summer MDs are recorded during period 01/10/2018 00:30 - 01/04/2019 00:00.
- ***EMBEDDED GENERATION*** data was obtained from the NETS/NODW as the aggregation of all measurable embedded generation at the time of system coincidence, on the Ergon Energy regulated network. Maximum demands are extracted at time of the Native Annual System Maximum Demand (COINCIDENT). Only those sites where Ergon Energy has 30 minute interval meters installed and recorded are used in this variable. The coincident values cannot be determined for sites without 30 minute interval metering. Estimates that up to 100 MW of micro-embedded generation is therefore not included in the metric ‘Embedded Generation’. Scheduled, semi-scheduled and non-scheduled embedded generation is used but not non-scheduled behind the meter is not considered. Ergon Energy is of the opinion that this would not introduce a material impact on the use of the information. A negative sign is used to indicate directional flow of energy
- ***Weather* Corrected *(10% Poe) Network Coincident MD*, And *Weather Corrected (50% Poe) Network Coincident MD.***

In order to obtain weather adjusted peak demand, Ergon Energy has employed a methodology involving:

- Daily temperature maximum and minimum observations are obtained from the Bureau of Meteorology for weather stations within the Ergon Energy franchise area.
- In reference to temperature correction, actual summed coincident demand at the Network Terminal Connection Point and embedded generation as read from NETS/NODW is weather corrected using the following: Constructing a set of multivariate maximum demand equation for both summer and winter season separately and for each of six separate regions comprising regional Queensland network over at least 10 years, using variables of Temperature (Maximum and minimum), Gross State Product (source Australian Bureau of Statistics-ABS), regional population numbers (source Queensland Government Statistician's Office) are obtained over the data set. These coefficients and equations are used to model demand for each of the six regions. The aggregation of regional temperature corrected demand at coincidence to the network peak provides the total temperature corrected demand
- The regions comprise Far North-FN, North-N, Central-CA, Mackay-MK, South East - SE and Wide Bay-WB. The terminal connection points which constitute each region are defined in the Substation Investment Forecasting Tool (SIFT)
- For each region, daily historical weather parameters (temperature maximums and minimums) are passed through the multivariate equation and maximum annual demand is obtained.
- The listing of annual peak demand is made for all set of consistent temperature to produce an associated histogram
- The annual peak demands were analysed / measured from the histogram to obtain 10 POE and 50 POE values.

Temperature correction using temperature data from historical years is an appropriate and recognised technique to produce temperature corrected peak demand values.

21.5 Assumptions

21.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER’s definition, for all variables in Table 5.3.1 for the regulatory reporting year.

21.7 Explanatory Notes

Not applicable.

22 BOP - 5.4 MD Utilisation Spatial

22.1 Scope of BOP

22.1.1 Table 5.4.1 Non-Coincident & Coincident Maximum Demand

22.2 Compliance with CA RIN Requirements

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN.

Of note, where an asset was not commissioned or de-commissioned for that regulatory year, the rating field is left blank. A ‘zero’ is a possible reading for maximum demand, therefore it would be inappropriate to enter ‘zero’ for demand prior to commissioning or following decommissioning.

Where available and/or relevant, Ergon Energy has also provided data in relation to Substation Rating, Adjustments – Embedded Generation, Weather Corrected Maximum Demand (for both 10% PoE and 50% PoE). Alternatively, these cells (shaded orange allowing for ‘blacking out’ if such information was not collected) have been blacked out or left ‘zero’ in line with the abovementioned comment.

Ergon Energy has prepared the information provided in Table 5.4.1 in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

22.3 Sources

Actual information for the following variables was sourced from the Substation Investment Forecasting Tool (SIFT), a joint Ergon Energy / Energex solution for, among other requirements, the containing of data for the production of network demand forecasts and the process of developing the network demand forecasts. Load measurement data within SIFT is populated from NEM settlements data, SCADA readings, Network Statistical metering (same standard as NEM type 4) and for those substations where no CTs nor VTs exist MD values are simulated from retail billing data, deemed daily demand profiles and premises connection topology.

The raw maximum demand used for weather correction is native demand.

- WEATHER CORRECTED MD 10% PoE
- WEATHER CORRECTED MD 50% PoE
- RAW ADJUSTED MD
- DATE MD OCCURRED

- HALF HOUR TIME PERIOD MD OCCURRED
- ADJUSTMENTS - EMBEDDED GENERATION. (Ergon Energy only has unscheduled Generation in the subtransmission network)
- WINTER/SUMMER PEAKING
- SUBSTATION RATING

22.4 Methodology

Relative to the provision of information in Template 5.4, Table 5.4.1 – Non-Coincident and Coincident Maximum Demand, Ergon Energy makes the following comments (including specific definitions of variables and sub categories applied):

- Those substations in group “SUBTRANSMISSION SUBSTATION” are Bulk Supply Substations which are wholly owned and maintained by Ergon Energy.
- No Transmission Connection Point (TCP) substations that supply Subtransmission voltages (>=66kV) have been listed.
- Transmission Connection Point (TCP) substations that supply distribution voltages (<=33kV) have been listed with the ZONE SUBSTATION grouping.
- Those substations that are privately owned have been listed as” (###) Private Substation” where ‘###’ is a unique code used by Ergon Energy forecasters to explicitly identify the RIN entry for internal audit purposes.
- Those substations that are Ergon Energy owned and supply a single consumer have been listed as” (###) Private Substation” where ‘###’ is a unique code used by Ergon Energy forecasters to explicitly identify the RIN entry for internal audit purposes.
- SUBSTATION RATING is taken to be the Normal Cyclic Capacity (NCC). NCC is the maximum permissible peak daily loading for a given load cycle that the substation can supply each day of its life.
- SUBSTATION RATING - Normal Cyclic Capacity (NCC) rating (in MVA) which does not vary between non-coincident and coincident peaks. Where no NCC rating is available, name-plate rating has been used for Ergon Energy assets, and Authorised Maximum Demand for customer-owned assets. Since using the SIFT solution as the source of the data for the CA_RIN the NCC rating is calculated slightly different. SIFT determines the smallest individual substation element NCC rating and multiplies this by the number of units installed at the

substation. The previous CA_RIN simply summated the individual elemental NCC ratings at a substation.

- ***RAW ADJUSTED MD*** – Cleansed (of switching events) Native Demand. This is an aggregate of the "As Delivered" substation raw readings with any downstream embedded generation raw readings. Maximum demands are extracted both at time of Seasonal System Maximum Demand (COINCIDENT) and Substation Seasonal Maximum Demand (NON-COINCIDENT). Effects of "temporary closure of major industrial customers" are not accounted for as Ergon Energy does not measure energy not supplied to a consumer. The MD reported is the highest average demand recorded over a half hour period within a season.

- Reported MVA values are at the time of RAW ADJUSTED MD MW readings. Ergon Energy currently does not store independent seasonal MVA peak readings.

- HALF HOUR TIME PERIOD MD OCCURRED – is the same as the NER definition of a "trading interval". The value reported for this variable is the 30 minute period ending on the hour or on the half hour over which the MD was recorded. The interval is identified by the *time* at which it ends.

- ***DATE MD OCCURRED*** – The date on which the native non-coincident and native coincident maximum demand of a substation was recorded in date format dd/mm/yyyy.

- ***WINTER/SUMMER PEAKING*** data reported aligns with Ergon Energy's own network demand forecasting cycles, under which Summer Peak is considered to occur in the period 1 October to 31 March inclusive while Winter Peak is considered to occur in the period 1 April to 30 September inclusive. This cannot correspond with the form of the definition of a regulatory year due to the seasonal nature of customer demand for energy on the network assets. For clarity, Ergon Energy forecasts with the latest available recorded annual maximum demands which are derived from measurements over the 12 month period ending summer. That is to say, for example, for the purpose of forecasting zone substation maximum demand, 2018-19 is the 12 month period ending 01/04/2019 00:00, of which winter MDs are recorded during period 01/04/2018 00:30 - 01/10/2018 00:00 and summer MDs are recorded during period 01/10/2018 00:30 - 01/04/2019 00:00.

- ***ADJUSTMENTS - EMBEDDED GENERATION*** – is the aggregation of embedded generation downstream of a substation. Maximum demands are extracted both at time of Annual System Maximum Demand (COINCIDENT) and aggregate embedded generation Seasonal Maximum Demand (NON-COINCIDENT). Only those sites where Ergon Energy has interval meters installed are used in this variable. A negative sign is used to indicate directional flow of energy, negative being energy delivered to the Ergon Energy network from the embedded generator (EG).

- ***COINCIDENT*** – variable measure at the time of Ergon Energy System Maximum Demand.
- ***NON-COINCIDENT*** – variable measured at time of substation or embedded generation annual maximum demand over the regulatory period.

Of note, over the required period there have been a number of large customer transfers to Powerlink Transmission Network Service Provider (TNSP) from Ergon Energy Local Network Service Provider (LNSP). As this load has not disappeared from the Queensland economy and for consistency of demand-to-GSP correlation these Transmission Network Connected Premises (TNCP) have been removed from the history provided. These TNCP connections have been at transmission voltages, not involving Subtransmission substations or zone substation assets. The AER requirement is to include these TNCP load history where a segment of a Distribution Network Service Provider's (DNSP's) network is transferred to the TNSP. As there have been no asset transfers from Ergon Energy with these TNCP transfers the AER ruling is deemed to have been adhered to.

Weather Correction of Raw Readings:

Daily temperature maximum and minimum observations are obtained from the Bureau of Meteorology for weather stations within the Ergon Energy franchise area. Each weather station associated with either the metered substation or metered connection point is chosen by its consistency of available weather data from the weather station over an acceptable continuous time period of 30 years to obtain the closest location to that metered point.

Raw aggregate coincident Native (with energy supplied by downstream embedded generation) substation demands are sourced from Ergon Energy's Network Operational Data Warehouse (NODW) previously the variables were stored in the Statistical Metering Database (SMDB). The Network Element Time Series Metering Tool (NETS) accesses NODW and stores network assets load information.

Weather corrected uses the following methods: within SIFT, coefficients for a multivariate equation using variables of Temperature (Maximum and minimum), Saturday, Sunday and holidays are obtained over each year's data set. These coefficients and equation are used to model maximum demands.

Historical weather parameters (temperature maximums and minimums) are passed through the multivariate equation to produce modelled daily peak demand commensurate with the daily temperatures.

The daily demand figures for three years were used to obtain annual peak demand figures over all previous temperature data sets.

Peak demands were analysed to obtain 10 PoE and 50 PoE values for each year.

In doing so, it was assumed that temperature correction using temperature data from all years is an appropriate technique applied to the current consumer base to produce temperature corrected peak demand.

The magnitude of temperature correction to the peak MW demand, expressed as a ratio of that demand is applied to the raw MVA value to provide temperature adjusted peak demand in MVA.

In cases where statistical metering has failed over long periods of time, estimates are derived from linear interpolation of like monthly readings (with a time stamp period the same as the previous year) and annual peaks drawn from these estimated monthly peaks. In these cases the time of peak is estimated to be the same as the previous.

22.5 Assumptions

Refer to Section 22.4 Methodology for assumptions applied.

22.6 Estimated or Actual Information

Ergon Energy has provided Actual Information, in accordance with the AER's definition, for all variables of Table 5.4.1. for a given substation (zone or subtransmission) where metering is available and functional for any given year.

Ergon Energy has used Estimated load readings when neither statistical metering nor SCADA is installed at a substation, or in cases where metering has failed for an extended period of time.

In cases where neither statistical nor SCADA metering is installed at a substation, estimates of demand are derived from consumer billed kWh, deemed energy profiles and network topology. Readings from these substations will continue to be based on energy sales and deemed profiles until such time as plant replacement allows for the inclusion of SCADA. These substations are of a low installed capacity and base cost construction.

In cases where metering has failed over long periods of time, estimates are derived from linear interpolation of like monthly readings and annual peaks drawn from these estimated monthly peaks.

22.7 Explanatory Notes

Not applicable.

23 BOP - 6.3 Sustained Interruptions

23.1 Scope of BOP

23.1.1 Table 6.3.1 - Sustained Interruptions to Supply

23.2 Compliance with CA RIN Requirements

Ergon Energy has prepared the information provided in Template 6.3 Sustained Interruptions, Table 6.3.1 - Sustained Interruptions to Supply in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and definitions in Appendix F to the RIN.

Ergon Energy has populated all variables for cells as required by the RIN.

Table 6.3.1 contains both planned and unplanned, completed interruption events

Table 6.3.1 contains sustained interruptions to supply applying the STPIS Appendix A, "inferred" definition of sustained interruption whereby the duration of interruption is greater than one minute.

Table 6.3.1 contains information that is consistent with Appendix E, 18.4. Interruption events that are excluded under Clause 3.3 (a) of the STPIS are identified in the "Reason for interruption" field of Table 6.3.1. The events that excluded through application of Clause 3.3 (a) present "0" in the "Effect on unplanned SAIDI (by feeder classification)" and the "Effect on unplanned SAIFI (by feeder classification)" fields with Table 6.3.1. [CA RIN Appendix E, 18.4]

An event caused by a customer's electrical installation or failure of that electrical installation which only affects supply to that customer is not deemed an interruption as defined, "A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network" STPIS 2009 and CA RIN Appendix E 18.2]. These events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation and as such are considered to be an event beyond the boundary of the electricity supply network and therefore excluded from Ergon Energy reported reliability performance under the STPIS.

Therefore an event caused by a customer's electrical installation or failure of that electrical installation present "0" " in the "Effect on unplanned SAIDI (by feeder classification)" and the "Effect on unplanned SAIFI (by feeder classification)" fields with Table 6.3.1.

Ergon Energy implemented system changes on 1 July 2015 to provide detailed reason for interruption requirements of Table 6.3.1. Actual data has been sourced directly from the interruption event record.

23.3 Sources

The data used to populate Table 6.3.1 has been sourced from outage event records within Ergon Energy's Outage Management System (FDRSTAT).

23.4 Methodology

Table 6.3.1 contains unplanned interruption events in which the required period of RIN was not provided prior to interrupting customers. These events included interruptions to supply to allow "Forced Corrective Maintenance" activities required to address emerging and identified equipment defects in order to prevent the occurrence of a wider spread interruption event or to prevent the occurrence of an equipment failure that results in a safety risk to personnel and the public. [CA RIN Appendix E, 18.3]

In order to obtain the information for the relevant regulatory year, Ergon Energy applied the following assumptions:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (>1min) interruptions
- A customer is defined as a premise having an assigned Active NMI with an Active Account. Customer numbers are held in the ECORP database.
- Ergon Energy notes that Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.

The methodology applied to provide the information in response to the RIN for the relevant regulatory year:

- ***Date of event*** records the date that the event commenced
- ***Time of interruption*** records the time the first customer was interrupted
- ***Asset ID (Feeder ID)*** records the Feeders asset number affected as identified in the FDRSTAT ECORP system.
- ***Feeder classification*** are Urban (UR), Short Rural (SR) & Long Rural (LR) as per the definitions in Appendix A of the AER's Electricity DNSP's, STPIS (November 2009). Reporting is based on the feeder's classification the end of the regulatory year.

- ***Reason for interruption*** records the detailed reason for interruption grouped by the RIN's grouping classification listed in Columns N of the supplied RIN Template 6.3.
- ***Detailed reason for interruption*** records the cause of why the interruption occurred grouped by the RIN's grouping classification listed in Columns O of the supplied RIN Template 6.3.
- ***Number of customers affected by the interruption*** records the number of customer interrupted on the feeder in the event.
- ***Average duration of sustained customer interruption*** is the calculated as the ratio of aggregate customer minutes interrupted and number of customers interrupted.
- ***Effect on unplanned SAIDI (by feeder classification)*** is the calculation of the sustained unplanned customer minutes experienced on the Feeder divided by average number of customers of the feeder's classification.(Note: planned, and other STPIS excluded events have no effect on unplanned SAIDI or SAIFI and as such will be reported as '0'.)
- ***Effect on unplanned SAIFI (by feeder classification)*** is the calculation of the sustained unplanned customers interrupted on the Feeder divided by average number of customers of the feeder's classification.(Note: planned, and other STPIS excluded events have no effect on unplanned SAIDI or SAIFI and as such will be reported as '0'.)
- ***MED*** identifies interruption events that occurred on a nominated Major Event Day (MED) in accordance with clauses 3.3 (b) of the AER's STPIS scheme. They are identified in the "MED" field of Table 6.3.1 and represented by "YES" in this column. The events that occur on a nominated MED present the contribution of the event to the feeder classification SAIDI and SAIFI in columns J and K of Table 6.3.1. [CA RIN Appendix E, 18.4].

23.5 Assumptions

23.6 Estimated or Actual Information

Ergon Energy has provided actual information that is sourced directly from the internal outage management system for the relevant regulatory year. Where information is provided it is done so in accordance with the AER's definitions and applying the assumptions and methodology that is described within this Basis of Preparation.

23.7 Explanatory Notes

Not applicable.