Category Analysis RIN
Basis of Preparation

2020-21

Part of Energy Queensland

Contents

BoP - 2.1 Expenditure Summary

Table 2.1.1 - Standard Control Services CAPEX

Table 2.1.2 - Standard Control Services OPEX

Table 2.1.3 - Alternative Control Services CAPEX

Table 2.1.4 - Alternative Control Services OPEX

Table 2.1.5 - Dual Function Assets CAPEX

Table 2.1.6 - Dual Function Assets OPEX

Compliance with the RIN Requirements

Capital Expenditure reported against activities in Table 2.1.1 have been extracted from individual templates.

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 2020-21 real dollars (Table 2.3.1) in respect of Augex this Table is not relevant to the Expenditure Summary.

Ergon Energy has no dual function assets.

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.

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. Analysis was undertaken in Ergon Energy's financial systems to identify duplications reported throughout the CA RIN. Duplicated amounts were identified and added to the reconciliation file.

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.

Assumptions

Refer to Estimated or Actual Information which describes assumptions made.

Estimated 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 2020-21, 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.

Explanatory Notes

Not applicable.

BoP - 2.2 Repex

Table 2.2.1 - Replacement Expenditure, Volumes and Asset Failures by Asset Category

Compliance with the 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.

Sources

The key data sources used to produce required information for RIN Template 2.2.1 are detailed in Table 1.1.

Table 1.1 Data Sources

Activity	System	Purpose
Expenditure and Replacement	General Ledger (GL) Transaction	Financial transaction for all replacement projects
	CAM and SAP EIP solution	Asset quantity acquire for each project
Asset Failures	Ellipse - Enterprise Resource Planning (ERP)	Asset information
	FeederSTAT - Outage Management System Application: (does not apply to SCADA)	Outage information
	SAP HANA	Database application

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 Tableau Prep and SAP Hana tool which includes all replacement projects that incurred expenditure and volume in the 2020-21 regulatory year under the replacement financial activity codes detailed in Table 1.2 below:

Table 1.2 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 (<=11kV).	maximum 12 months
Substation program (C2020, C2015 & C2025)	Sub-Transmission replacement projects - overhead lines and Underground Cables (=11kV).	12 months to max of 4-5 years

- Tableau Prep and 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, 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 2020-21.
- 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 2020-21 financial year expenditure.

Table 1.3 Repex Transaction Codes

Transaction No:	Expense Element	Transaction Amount	Repex Asset Category
67241280000	Labour	$25,000	Unknown
71872900000	Material	$3,000	Pole ; < = 11kV
71872900001	Material	$500	Pole top ; <= 22kV
71872900002	Material	$2,000	Fuse

71872900003	Material	$25,000	< = 11 kV ; Switch
71872900004	Material	$10,000	Non AER material (e.g. porcelain insulator)
27874220000	Contract	$10,000	Unknown
67241280000	Other	$31,981	Unknown
	Total	$107,481	

- As shown in Table above, material expenditure with Repex asset category will pass through directly to respective AER asset class. In the example:
  - $3,000 will be allocated to AER asset class 'Pole >1kV & <= 11kV; Wood', and
  - $500 to "Pole Top; >11kV & <= 22kV",
  - $2,000 to "Fuse" and $25,000 in "<= 11kV Switch"
  - in Repex Table 2.2 expenditure template.
- To allocate remaining unknown expenditure ($25,000 + $10,000 + $31,981 = $66,981), 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.

Step 3 (b) - Apportionment Methodology - Lines Program without Stock Code

- Projects with transaction that do **not** have AER stock code will be allocated to the respective Repex asset category based on the J3 codes with the associated percentages towards each category. These percentages are driven by the nature of the projects and the expenditure apportionment of the allocated items in the current year as shown as the table below. Percentages will vary from year to year depending on the projects undertaken during a specific year.

Table 1.4 Repex Apportionment Percentage

J3 Code		Asset Class		Percentage
AA	D-ABS, Link, Fuse - Upgrade/Replace	**A003**	11kV Wood Pole	5%
AA	D-ABS, Link, Fuse - Upgrade/Replace	**B003**	22kV Pole top	5%
AA	D-ABS, Link, Fuse - Upgrade/Replace	**G001**	Fuses LV&11kV	10%
AA	D-ABS, Link, Fuse - Upgrade/Replace	**G004**	Isolators 22kV	80%

Table 1.5 Apportioned Repex Expenditure

Pole; <= 11 kV; Wood	= 5% x $ 90,000	$4,500
Pole top; < = 22 kV	= 5% x $ 90,000	$4,500
Fuse; < = 11 kV	= 10% x $ 90,000	$9,000
Switch; < = 22 kV	= 80% x $ 90,000	$72,000
Total	***100%***	***$90,000***

Step 3 (c) - Apportionment Methodology - Substation Program

- As not all substation project materials have stock codes information allocated to project because these stocks are procured after the project financial approval and also the lifecycle of substation project is typically more than one year. In the initial year, planning and design would happen and based on the scope of the project, procurement and construction happen during the second or third year. Therefore, 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.

Replacement Volume Process

Step 1 and Step 2 are as same as illustrated in Replacement Expenditure process

Step 3 (a) - 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.

Step 3 (b) - Replacement Volume - Substation Program

- The lifecycle of substation program/projects are typically a minimum of one year to maximum of four to five years
- The replacement volume is derived from corporate asset management system –
    - Primavera P6 – commission date and
    - Ellipse – asset attribute
- First step is to manually look for 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
- For the respective REPEX work request numbers, commission financial year obtain from P6
- 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.

From 2019-20, pole staking volume methodology used the count of the pole staking work order quantity with the following conditions:

- Work order complete date within reporting financial year
- Work order with Standard Job code of "AIDR01"
- In 2020-21, Ergon started to stake poles proactively. 936 poles had been staked. As the business process allow these staking happened under a single work order, this proactive staking volume is manually allocated to the template.

Asset Failures

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

- Pole, Pole Top, Overhead Conductors, Underground Cables, Service Lines and Distribution Transformers.

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 refined its approach 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 had included both Assisted and Unassisted Failures, and defect replacement into the submission. Therefore, the asset failure counts were 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:

1. 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 2020-21 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.

Methodology C (SCADA):

The information was compiled utilising the Maintenance Strategy Support System (MSSS Code) codes configured within ERP Ellipse work order fields.

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.

Failure data for SCADA Systems is downloaded from Ellipse and imported into a spreadsheet. Additional Columns for **Asset Class** and **Asset Subclass** are added to the spreadsheet and Categorised accordingly to enable filtering or pivot table to be created.

The pivot table is further filtered by CONSEQUENCE_DESCRIPTION to enable a count of unassisted asset failures by Asset Class.

Filters to identify Asset Failure used are:

- Repair
- Replace
- Restore.

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.

All public lighting asset information has been removed from this template. Refer to Explanatory Notes.

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:

1. 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. Ergon network uses standard pole, poletop and conductor design to infer material voltages. As poles, pole tops and conductors can be used in different voltages other than the standard design, Ergon uses the work order feeder information to increase the accuracy of voltage assign, e.g. the quantity and expenditure of a 66kV designed pole in project – “*PN FD-1298 Northern 002 Std Job P2s”* has been reassigned to 11kV due to feeder FD – 1298 is a 11kV feeder.

Feeder No	Feeder Name		Voltage
FD-1298	201 - Northern [SARI 11kV]	[SARI 11kV]	11kV

Estimated Information

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

- Expenditure by Asset Category (2020-21)
- Asset Replacements (2020-21)
- Asset Failure (2020-21).

Explanatory Notes

Expenditure and Replacement

In regard 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 subcategories reconcile to the higher level asset 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.
- Activity Codes C2000, C2015, C2020 and C2025 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.
- Current J3 Code expenditure allocation for the lines program is a refinement process of the previous years. Previously, the total unallocated expenditure were apportioned across all lines asset as the detail individual actual J3 Code apportionment % was not available due to legacy system restriction. Therefore, the current year methodology is a refinement of the previous year.
- The sum of the asset group replacement expenditures is equal to the total replacement expenditure contained in template 2.1 (Expenditure Summary). Refer to reconciliation below.
- In 2020-21 Ergon Energy commenced reporting all Public Lighting replacement capital expenditure and volumes in Template 4.1 Public Lighting and discontinued recognising this service in Template 2.2 Repex. Historically, where Ergon Energy operationally bundled together Standard Control Services (SCS) and Alternative Control Services (ACS) capex works, Public Lighting was reported in Template 2.2 Repex. This clear separation will reflect the AER service classifications in Attachment 12: Classification of Services in Ergon Energy's 2020-25 Distribution Determination for Template 2.2 Repex (SCS) and Template 4.1 Public Lighting (ACS).
- For comparative purposes, reporting for Public Lighting replacement capital expenditure and volumes is recognised as follows:

  Prior to 1 July 2020:

  - Template 2.2 Repex
  - Table 2.2.1 - Replacement Expenditure, Volumes and Asset Failures by Asset Category
  - Public Lighting By: Asset Type; Lighting Obligation.

  From 1 July 2020:

- Template 4.1 Public Lighting
- Table 4.1.2 - Descriptor Metrics Annually
- Light Replacement.

General issues

In distribution businesses it is very common for projects to span several 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 2020-21 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 2020-21 regulatory year was $9.7 million.

The unallocated expenditure consists of following categories:

- Defect remediation and return to service projects without AER asset class
- Queensland bush fire response without AER asset class
- Asbestos related projects
- Underground pillar covers
- Meters
- LV monitors
- Batteries / Charger
- Surge Diverter
- Miscellaneous substation assets such as electrical equipment cabinets, fence and lighting fixtures.

Reconciliation:

The difference between data from the project ledger and the general ledger is 0.26% ($984,439), mainly due to different methods in filtering out the Non SCS/Non System components. This 0.26% variation is included in the “Other non AER Asset Categories”. 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 does not go down to a level below Project level - so Project 'J Code' proxies are identified to try to approximate the BPU deductions - but they are not the same. The difference is applied to categories within the replacement costs proportionately to align to the general ledger.

Table 2.2.2 - Selected Asset Characteristics

Compliance with the 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.

Sources

Information has been sourced from the below systems:

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

Methodology

Asset Volumes Currently in Commission

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.

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.

Asset Replacements

All asset replacements for the following classifications were proportioned in accordance with the "Asset Volumes Currently in Commission":

- Feeder classification and material type:
    - Total Poles By: Feeder Type
    - Overhead Conductors By: Conductor Length by Feeder Type
    - Overhead Conductors By: Conductor Length Material Type
    - Underground Cables By: Cable Length by Feeder.

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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated Information

Ergon Energy has provided Actual Information.

- Currently in commission
- Feeder classification and material information reconciles with Template 5.2.

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

- Replacements

Explanatory Notes

Asset Volumes Currently in Commission

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.

Asset Replacements

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.

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.

BoP - 2.3 Augex

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

Compliance with the 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 included projects and expenditure related to augmentation of the network, recording data from projects under financial activity codes C2030, C2035, C2040, C2045, C2046, C2047, C2048, C2050, C2055, C2580, C2120 & C3050, 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 nonmaterial 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": 'Normal Conditions - holds true where all network elements are in service allowing the application of Normal Cyclic Capacity (NCC) ratings of equipment. This is in opposition to where network elements are out of service, such as applied network contingency events where Emergency Cyclic Capacity (ECC) rating are employed."

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 2020-21. 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 **Ergon Energy T2.3 AGX (Nominal to Real) 30 Nov 2021.**
- 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.

Note: No 2.3.1 Material Projects were identified this RIN Period.

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.

Sources

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

Methodology

Report was run from the Ellipse operating system which listed all Augex related projects closed within regulatory year under the financial activity codes C2030, C2035, C2040, C2045, C2046, C2047, C2048, C2050, C2055, C2580, C2120 & C3050, - the MASTER_RIN_AUGEX_Raw_Data_Extract 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). 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.

Note: No 2.3.1 Material Projects were identified this RIN Period.

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_RIN_AUGEX_Raw_Data_Extract report:

Non Material Projects - Total Direct Expenditure was sourced from the MASTER_RIN_AUGEX_Raw_Data_Extract report. The total cumulative expenditure (excluding overheads, land and easement costs) over the life of the projects identified as non- material projects as per the MASTER_RIN_AUGEX_Raw_Data_Extract 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_RIN_AUGEX_Raw_Data_Extract 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_RIN_AUGEX_Raw_Data_Extract report. Land and Easement cost are calculated by running an Ellipse report for activities C2030, C2040, C2045, C2046, C2047, C2048, C2050, C2055, C2580, C2120 & C3050 by expense element 6160 (Easement/Land), the MASTER_Txns_with_EE_6160 report. This report provided the total land and easement cost per project. **No Easement/Land costs were identified for 2.3.1 projects**

Note: no 2.3.1 Material Projects were identified this RIN Period

Converting nominal to real values

Ergon Energy has reported all expenditure data for augex in Table 2.3.1 in real 2020-21. Nominal dollars have 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_RIN_AUGEX_Raw_Data_Extract 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:

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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated Information

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

- Non Material Projects - Total Direct Expenditure
- Non Material Projects - Years Incurred.

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.

Explanatory Notes

It should be noted that for the purposes of CA RIN 2.3(b), in classifying expenditure Ergon have applied a general principle to classify projects as to their primary purpose. Within Ellipse, projects are set up with "J-Codes" which identify projects as to this purpose. As such, expenditure is categorised and grouped under a single category per project. An example code is "D-Lines – Subtransmission". Where a project has this J-Code, all expenditure relating to this project is categorised as Subtransmission line expenditure.

Table 2.3.2 - Augex Asset Data - Subtransmission Lines

Compliance with the 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 included projects and expenditure related to augmentation of the network, recording data from projects under financial activity codes C2030, C2035, C2040, C2045, C2046, C2047, C2048, C2050, C2055, C2580, C2120 & C3050 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 2.3.2 - Augex Asset Data - Subtransmission Lines

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 $ 2020-21. 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 **Ergon Energy 2021CA T2.3 AGX A1(Nominal to Real).**

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

- No Subtransmission lines augmentation projects in Table 2.3.2 are related to other projects, including other tables in template 2.3(a).
- 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 2.3.2.
- All augmentation work on Subtransmission lines in Ergon Energy's network was included in Table 2.3.2.

With regards to Land and Easement expenditure:

- 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 2.3.1.
- Furthermore, Ergon Energy input all expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively, including legal, stamp duties and cost of purchase or easement compensation payments.

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": 'Normal Conditions - holds true where all network elements are in service allowing the application of Normal Cyclic Capacity (NCC) ratings of equipment. This is in opposition to where network elements are out of service, such as applied network contingency events where Emergency Cyclic Capacity (ECC) rating are employed."

Sources

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

Methodology

Report was run from the Ellipse operating system which listed all Augex related projects closed within regulatory year under the financial activity codes C2030, C2035, C2040, C2045, C2046, C2047, C2048, C2050, C2055, C2580, C2120 & C3050 - the MASTER_RIN_AUGEX_Raw_Data_Extract 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). 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.

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_RIN_AUGEX_Raw_Data_Extract report. The total cumulative expenditure (excluding overheads, land and easement costs) over the life of the projects identified as non- material projects as per the MASTER_RIN_AUGEX_Raw_Data_Extract 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_RIN_AUGEX_Raw_Data_Extract 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_RIN_AUGEX_Raw_Data_Extract report. Land and Easement cost are calculated by running an Ellipse report for activities C2030, C2040, C2045, C2046, C2047, C2048, C2050, C2055 C2580, C2120 & C3050 by expense element 6160 (Easement/Land), the MASTER_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, 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 was applied to the total Land and Easement expenditure as per MASTER_Txns_with_EE_6160 report for each project and input as Land purchase or Easements in Table 2.3.2.

Converting nominal to real values

Ergon Energy has reported all expenditure data for augex in Table 2.3.2 in real $ 2020-21. Nominal dollars have 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_RIN_AUGEX_Raw_Data_Extract 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:

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.

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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated Information

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 – Easement Purchase

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.

Explanatory Notes

It should be noted that for the purposes of CA RIN 2.3(b), in classifying expenditure Ergon have applied a general principle to classify projects as to their primary purpose. Within Ellipse, projects are set up with “J-Codes” which identify projects as to this purpose. As such, expenditure is categorised and grouped under a single category per project. An example code is “D-Lines – Subtransmission”. Where a project has this J-Code, all expenditure relating to this project is categorised as Subtransmission line expenditure.

BoP - 2.3 Augex B

Table 2.3.3 - Augex Data - Hv/lv Feeders and Distribution Substations

Table 2.3.3.1 Descriptor Metrics

Compliance with the 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 included projects and expenditure related to augmentation of the network, recording data from projects under financial activity codes C2030, C2035, C2040, C2045, C2046, C2047, C2048, C2050, C2055, C2580, C2120 & C3050, 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 Substations 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 and financially finalised in the reported RIN financial year.

Sources

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 Finalised
    - Augex 2.3.3 Metric Class, quantifying the reporting category under which each Stock Item is quantified
- Raw conductor and cable acquisition (by metre) was sourced from CA_Augex_RIN_Requisition _Data report.

Methodology

In order to obtain the information, it was necessary for Ergon Energy to apply additional data qualifiers to MASTER_RIN_AUGEX_Raw_Data_Extract report to allow identification of each parcel of works by Distribution categories in accordance with the requirements of Table 2.3.B

- All Projects with Project Category (J2) Codes of either Subs-Sub-Transmission, Subs-Transmission, Lines-Sub-Transmission & Lines Transmission, applicable to Table 2.3 (A) are outside the requirements of Table 2.3 (B) and were eliminated from the reporting set.
- Distribution Categories were identified from the reporting suite through the use of Project Category (J2) Codes Lines to delineate Distribution data.
- Distribution Categories were identified as either New or Upgraded assets 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 and Works Request identifiers, such as, but not limited to:
    - Equip ID Prefix SP = Substation Pole Mounted

- Equip ID Prefix GT = Ground Mounted Network Slot
- Equip ID Prefix AB = HV Isolating Device Network Slot
- 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, all, if 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_Txns_with_EE_6160 Report. Reported RIN Period Data from the above report was imported into the 2.3.B_Master 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 subtransmission 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 Requisition Transactions 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. This anomaly is avoided through the methodology by which all material

transactions are reported, regardless of financial year, for only those projects that have been financially finalised in the period of return, therefore assuring that all transactions, including material returns, have been accounted.

- 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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated 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.

Overhead and Underground line lengths were deemed to be actuals based on the level of granularity in the Inventory Stock Section 10 (SS10) codes which categorises and quantifies conductor and cable with a linear conversion factor (metres per kilometre of circuit) including SWER Conductor, at the inventory stock level.

Explanatory Notes

RIN Reference 7.2(c)(i) and 7.3(c)(i)

Requirement: Where expenditure has been reported in real 2020-21, provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.

Attachments: EE2021CA T2.3 AGX A1(Nominal to Real).

It should be noted that for the purposes of CA RIN 2.3(b), in classifying expenditure Ergon have applied a general principle to classify projects as to their primary purpose. Within Ellipse, projects are set up with "J-Codes" which identify projects as to this purpose. As such, expenditure is categorised and grouped under a single category per project. An example code is "D-Lines – Subtransmission". Where a project has this J-Code, all expenditure relating to this project is categorised as Subtransmission line expenditure.

Table 2.3.3 - Augex Data - Hv/lv Feeders and Distribution Substations

Table 2.3.3.2 Cost Metrics

Compliance with the RIN Requirements

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.

Sources

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

Methodology

In order to obtain the information, it was necessary for Ergon Energy to apply additional data qualifiers to the MASTER_RIN_AUGEX_Raw_Data_Extract report to allow identification of each parcel of works by Distribution categories in accordance with the requirements of Table 2.3.B:

- 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 (B) and were eliminated from the reporting set.
- Distribution Categories were identified from the reporting suite through the use of Project Category (J2) Codes Lines to delineate Distribution data.
- Distribution Categories were identified as either New or Upgraded assets 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 and Works Request identifiers, such as, but not limited to:
    - Equip ID Prefix SP = Substation Pole Mounted
    - Equip ID Prefix GT = Ground Mounted Network Slot
    - Equip ID Prefix AB = HV Isolating Device Network Slot
    - 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, all, if 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_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 subtransmission 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 Requisition Transactions 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. This anomaly is avoided through the methodology by which all material transactions are reported, regardless of financial year for only those projects that have been financially finalised in the period of return, therefore assuring that all transactions, including material returns, have been accounted.

    - 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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated 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.

Explanatory Notes

RIN Reference 7.2(c)(i) and 7.3(c)(i)

Requirement: Where expenditure has been reported in real $2020-21, provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.

Attachments: EE2021CA T2.3 AGX A1(Nominal to Real).

It should be noted that for the purposes of CA RIN 2.3(b), in classifying expenditure Ergon have applied a general principle to classify projects as to their primary purpose. Within Ellipse, projects are set up with “J-Codes” which identify projects as to this purpose. As such, expenditure is categorised and grouped under a single category per project. An example code is “D-Lines – Subtransmission”. Where a project has this J-Code, all expenditure relating to this project is categorised as Subtransmission line expenditure.

Table 2.3.4 - Augex Data - Total Expenditure

Compliance with the RIN Requirements

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_RIN_AUGEX_Raw_Data_Extract 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 $ 2020-21 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.

Sources

Actual Information for the financial variables was sourced from Ergon Energy's Ellipse operating system, using the MASTER_RIN_AUGEX_Raw_Data_Extract report which includes a validation of Financial Year to Date values against the Augex CAM Recast Data.

Methodology

Data disclosed in Table 2.3.4 was sourced from the MASTER_RIN_AUGEX_Raw_Data_Extract 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 C2030, C2035, C2040, C2045, C2046, C2047, C2048, C2050, C2055 C2580, C2120 & C3050 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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated 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.

Overhead & Underground line lengths were deemed to be actuals based on the level of granularity in the Inventory Stock Section 10 (SS10) codes which categorises and quantifies conductor & cable with a linear conversion factor (metres per kilometre of circuit) including SWER Conductor, at the inventory stock level.

Explanatory Notes

RIN Reference 7.2(c)(i) and 7.3(c)(i)

Requirement: Where expenditure has been reported in real $ 2020-21, provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.

Attachments: EE2021CA T2.3 AGX A1(Nominal to Real).

It should be noted that for the purposes of CA RIN 2.3(b), in classifying expenditure Ergon have applied a general principle to classify projects as to their primary purpose. Within Ellipse, projects are set up with “J-Codes” which identify projects as to this purpose. As such, expenditure is categorised and grouped under a single category per project. An example code is “D-Lines – Subtransmission”. Where a project has this J-Code, all expenditure relating to this project is categorised as Subtransmission line expenditure.

BoP - 2.5 Connections

Table 2.5.1 Descriptor Metrics

Compliance with the RIN Requirements

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

Ergon Network 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 Network 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 Network has not distinguished expenditure between Standard and Alternative Control Services (ACS). Similarly, Ergon Network 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 Network 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 Network. 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).
- 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 Network 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.

Sources

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

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

Cherwell was used to provide:

- GSL Breaches (via DMK530)
- GSL Payments (via DMK530)
- Customer Complaints (via SQL query of the EDW).

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 RATS AFO EIP Model FIC3013 Ellipse (Regulatory) report 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 ($).

Methodology

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 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 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 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, Major Customer Connection, Additions & Alterations, Establish Supply, New Connection or Existing 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
- Cross checked with a yearly report
- 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

- GSL payments are established by summing the total financial amount of New Connection GSLs paid for each financial year.

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 Alterations' and 'New Connection' classifications added in from the 2019-20 FY onwards due to a change made in the 2018-19 financial year to the activity codes used.
- 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.

<u>System Attributes & Categorisation</u>

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:

- Commercial 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 2020-21
- 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 categorisation
- 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.

Assumptions

GSLs are payable to small NMI class customers only therefore data provided has been based on the assumption that a small NMI classification is that of a residential customer.

Estimated 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 2020-21, for both financial and non-financial information:

- 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 $0's
- Distribution substation installed - total spend 0's
- Overhead lots
- Underground lots
- Cost per lot ($).

Explanatory Notes

In September 2019 Energex and Ergon Energy standardised the categories they use across their two instances of Cherwell. This has allowed for more accurate capturing of categories of complaints and permitted a standardised approach to the AER category mapping. This has meant that the volume of complaints has significantly reduced in the 'other' category while increasing in 'administrative process or customer service' and 'connection or augmentation'. This reflects more accurate categorisation including connection related complaints.

Table 2.5.2 Cost Metrics by Connection Classification

Compliance with the 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 2.5.2 - 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.

Sources

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 ($).

Methodology

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 Transformer 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

- Where there is no HV cable and no transformer counts, it will be assigned as "Complex connection LV"
- Where there is no HV cable with greater than or equal to 1 transformer count, it will be assigned as "Complex connection HV (no upstream asset works)"
- Where there is greater than or equal to 1 HV and greater than or equal to 1 transformer count, it will be assigned as "Complex connection HV (with upstream asset works).

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.

Assumptions

Not applicable.

Estimated Information

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).

Explanatory Notes

Not applicable.

BoP - 2.6 Non Network

Table 2.6.1 - Non-network Expenditure

Compliance with the 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.

If expenditure is directly attributable to an expenditure category in this RIN Template 2.6 it is a direct cost for the purposes of this RIN Template 2.6 - irrespective of whether any of these direct costs are also classified as corporate overheads, network overheads or other capex or opex categories.

The CA RIN template 2.6 for Non-Network Fleet has been prepared consistent with Energy Queensland's Cost Allocation Method (CAM).

The CAM sets out the principles and policies for attributing direct costs and allocating indirect costs between different categories of distribution services, that is, between direct control services (standard control services [SCS] and alternative control services [ACS]) and unregulated distribution services.

The CAM is also used to attribute and allocate costs to non-distribution services, ensuring that only those costs associated with Ergon Energy and Energex's distribution services are then attributed to, or allocated between, the categories of distribution services.

Non-Network overheads for Fleet operating costs, property occupancy and facility management are classified as indirect to the extent that they cannot be directly attributed to a service. The costs of these shared 'support' activities are allocated via the Cost Allocation Method (CAM) across different categories of services as appropriate.

Non-Network opex and capex is allocated to the distribution businesses, Yurika and Retail on the basis of their share of labour because there is a causal relationship for the need for and use of non-network activities. The allocation of non-network costs will only occur where there is usage of these assets by the respective line of business. Where practical, Non-Network Capex has been directly attributed. In the case of Fleet, costs incurred are considered shared amongst the two DNSPs and, hence, are not directly attributable.

Table 2.6.1 - Non-Network Expenditure

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

- In RIN Table 2.6.1, in relation to the Non-network Other expenditure category, if Ergon has incurred $1 million or more (nominal) in capital expenditure for a given type or class of assets (e.g. Mobile generators), Ergon has inserted a row in the RIN Template and report that item separately.

- There have been additional Non-network Other expenditure categories introduced where Energex has reported categories that were not included in the Ergon DNSP Other expenditure Category in previous years, even though the incurred costs are less than $1 million. These categories are Other: Mobile Generators and Other: Fleet plant & Equipment.
- 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.
    - Network metering recording and storage at non network sites.
- For Motor Vehicles expenditure, Ergon has:
    - Reported expenditure in accordance with the AER's asset category definitions.
    - 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).
    - 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)

Sources

IT & Communications

Actual Information for the variables was sourced from the FIC3018 SAP Regulatory model (i.e. GL adjusted for regulatory differences).

Motor Vehicles, Buildings and Property, Other

The sources from which Ergon obtained the required information for Non-Network CAPEX, OPEX and metrics for Fleet:

- Ellipse Regulatory Model FIC3013 for Ellipse Financial Reports
- Ellipse Regulatory Model FIC3013 for detailed Transaction Reports for Capex Purchases
- Ellipse Regulatory Model FIC3013 for detailed Transaction reports for Fleet and Tools operating costs and supporting fleet functions.

Fleet listing sources from the Fleet intelligence portal, including disposals to cross reference Ellipse Capex reports into Asset Categories:

- Average kms per vehicle category and Units held at end of year data sources from the EQL Fleet Tableau data base
- SG Fleet transactions relating to Energex and Ergon Fleet Assets to determine the costs by Fleet Category sourced from the EQL Tableau data base in compliance with the RIN Requirements.

Methodology

IT & Communications

The capex and opex figures have been determined as follows:

- Data was sourced from the FIC3018 SAP Regulatory model for the opex and the capex. To assist with lower level classification, additional detail was obtained through Work in Progress and transaction reports.
- Client devices capex was extracted from the direct purchase Work in Progress codes which were analysed to identify client device expenditure. Client devices opex were based on smart phone and tablet expenditure.

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 the Total Non-Network ICT opex expenditure excluding Client Devices Expenditure. A percentage to represent the ICT cost applicable to Ergon Energy Standard Control Services has been applied. The percentage applied was sourced from RIN Table 2.10 Overheads template.

The outcome above has been reconciled to the non-network ICT opex costs captured and reported against S4 Functional Area 900006 - Indirect NN ICT.

These costs are captured as a 'pool' of NN opex against company code 1000 – Energy Queensland Ltd and not against the specific DNSP's (Ergon Energy & Energex).

S4 report 'FIC3018 Regulatory Model (S4 adjusted for regulatory adjustments) is run for the financial year with the parameter of Functional Area 900006.

The total is filtered to exclude GL Code 942013 NN Allocation ICT which is the GL code used to allocate NN ICT opex to services.

The percentages of total Non-Network opex allocated to each of the entities is calculated and these percentages are used to allocate the total Non-Network ICT opex pool to the entities.

The SCS percentage is applied to the allocated Non-Network ICT opex for each DNSP.

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).

Change in Methodology

The above method is a change from prior years/regulatory periods as to how Non Network IT & Communications capex has been calculated for the DNSP's.

Previously, IT & Communications capex was reported as Client device expenditure or Non-recurrent expenditure. No IT & Communications capex was reported as recurrent expenditure.

To better align with AER Definitions, non-recurrent projects have been explicitly identified and reported. Recurrent expenditure is the residual after subtracting the total non-recurrent capex and client device capex from the total reporting IT & Communications capex.

Motor Vehicles - OPEX:

If expenditure is directly assigned to an expenditure category in this RIN Template 2.6 it is a Direct Cost for the purposes of this RIN Template 2.6 including costs incurred to support the management of Fleet portfolio.

Ergon has reported the data in line with the AER definition of Car, Light Commercial Vehicles, Elevated Work Platforms and Heavy Commercial.

In RIN Table 2.6.1, in relation to the Non-Network Other expenditure category, if Ergon has incurred $1 million or more (nominal) in capital expenditure for a given type or class of assets (e.g. mobile generators), Ergon has inserted an additional row in the RIN Template to report that item separately.

There have also been additional categories introduced as a result of the alignment of the Fleet and Tools cost models, where Energex has historically reported categories that was not included in the Ergon DNSP categories, even though the incurred costs are less than $1 million, in order to align the approaches between Energex and Ergon.

Ergon has nominated, and reported separately, expenditure for the following Service Subcategories and Asset Categories.

- Other: Mobile Generator
- Other: Fleet plant & Equipment.

Change to Methodology

The above method is a change from prior years/regulatory periods as to how Non-Network Fleet and Tools related opex and capex has been calculated for the DNSPs.

Previously, the costs for Ergon DNSP were calculated by referring only to the Non-Network Fleet and Tools related opex and Capex spend captured directly against Ergon district responsibility centres and activities along with a 50% share of EQL Fleet and Tools opex and capex spend.

The CAM for 2020-25 regulatory period now treats the Non-Network Fleet and Tools related Opex and Capex of both DNSP's and EQL entity as a shared cost that is pooled together and then allocated to services based on CAM percentages that are calculated through the CAM and reviewed and adjusted annually where required.

Additionally, the implementation of a new ERP and change in cost model in Energy Queensland means that all Non-Network Fleet and Tools related opex and capex is now costed against the Energy Queensland company (code 1000) and differentiation of spend between the DNSP's will not be easily identifiable.

Based on these CAM and ERP system changes it has been determined that Ergon Energy and Energex should align with the CAM in the method used to calculate Non-Network Fleet and Tools related opex and capex for RIN reporting.

Aside from the above change, the Tools opex now includes the Procurement and Supply functions as part of the Non-Network Tools opex costs which used to be excluded in the previous regulatory reporting period. This is due to following the CAM allocation of the Non-Network pools from the 2020-25 regulatory period.

There has been change between what is classified as car vs light commercial category from the 2015-20 regulatory period to the 2020-25 regulatory period. This has resulted in 4x4 light passenger Fleet (Ford Ranger, Nissan Patrol, etc.) now considered as part of the Light commercial category as opposed to the previous classification as a car. This step was taken to ensure the consistent application of Fleet categories between the Energex and Ergon DNSP's from the 2020-25 regulatory period.

Non-Network Fleet Opex

All effort contributed in the Fleet support functions and its associate indirect costs, are closely aligned to the maintenance costs incurred for the maintenance of each fleet category.

OPEX

The below approach was taken to report the Non-Network Fleet and Tools in the categories as outlined in the CA RIN for Ergon.

Obtained Ellipse Regulatory Model FIC3013 and FIR3029 GL Transactions relating to the Functional Areas 900008 (Fleet) and 900009 (Tools) and all Indirect Fleet costs that are captured against the Fleet and Transport categories.

Allocate all Generation cost centres to the generation category as they are responsible for the on-going function of the generators. Allocate Functional Area 900009 to Tools and Equipment as this captures all costs associated within the on-going function of the Tools & Equipment

Reviewed the above reports and transactions with Department Managers for Generator Services, Plant Workshops, to determine their nature, i.e. Heavy Commercial Vehicle, Elevated Work Platform categorisation.

Obtained the annual expenditure report by Asset Category by Expense type e.g. Repairs, Maintenance, Fuel & Registration provided by SG Fleet. This information was used as the basis for the asset category split applied to the data in the Functional Areas 900008.

1. Specific spend that could be reported against individual asset categories is detailed as follows:
   Plant Workshops Department repair, test and maintain plant for EQL e.g. Heavy Commercial Vehicles (HCV) with Elevated Work Platforms, HCV Crane Borers. Work orders were used to determine costs relating to HCV – EWP, HCV Crane Borers and Heavy Commercial.
   Fringe Benefits Tax (FBT) was allocated 100% to Network Expenditure Light Commercial Vehicle, as all other Motor Fleet and Tools are excluded from FBT.
   Employee Contributions were allocated 100% to Non-Network Operating Expenditure of Light Commercial Vehicles. Particular positions within Energex and Ergon Energy require the employee to have a vehicle. The vehicle is also available for the employee's private use. For this privilege, the employee pays a contribution to Energex and Ergon to offset the value of this private use, via salary sacrifice. (Contributions are deducted from operating expenditure)
2. Any additional costs that could not be directly attributed to an individual asset category were allocated across the asset categories using proportion of the spend in each Fleet asset category based on the SG Fleet data.
3. In all instances, depreciation was excluded from the reported opex costs.
4. In all instances, only indirect costs were reported.

The output of the calculation above has been reconciled to the Non-Network Fleet and Tools opex costs captured and reported against S4 Functional Area 900008 - Indirect NN Fleet, Functional Area 900009 - Indirect NN Tools along with Fleet operating costs incurred for the fleet relating to costs centres in the Network and Corporate overhead pools.

These costs are captured as a ‘pool’ of Non-Network opex against company code 1000 – Energy Queensland Ltd and not against the specific DNSP’s (Ergon Energy & Energex).

S4 report ‘FIC3018 Regulatory Model (S4 adjusted for regulatory adjustments) is run for the financial year with the parameter of Functional Areas 900008 and 900009.

The total is filtered to exclude GL Code 942010 NN Allocation Fleet and 942011 NN Allocation Tools which is the GL code used to assign Non-Network Fleet and Tools opex to services respectively.

A ‘Non-Network Capex allocation by expenditure type’ template determined during the budget process for 2020-21 FY which is closely aligned to the proportions of how actual work is carried out, is the shared cost percentage for each of the DNSP (total fleet and tools capex budget).

The SCS percentage is applied to the allocated Non-Network Fleet and Tools opex for each DNSP.

CAPEX

Ergon applied the following approach to obtain the required information for Non-Network Fleet and Tools Capex Expenditure:

1. Obtained the Ellipse Regulatory Model FIC3013 and FIR3029 GL Transactions for Fleet, Tools and Equipment. These reports were used to identify the total of the financial purchases in the 2020-21 year.
2. The Ellipse Regulatory Model FIC3013 and FIR3029 GL Transactions was used to report the capital purchases, using the unique fleet number to identify the applicable asset categories. As a result of a requirement to make progress payments on certain assets due to the length of time that these assets take to build (in order to mitigate some of the suppliers' financial risk), transactions are recorded over several months. The only progress payments are applicable were Elevated Work Platforms category.
3. Per Clause 10.5 of the CA RIN, Ergon has incurred $1 million or more in capital expenditure for one class of assets and this is therefore reported separately. The additional asset classes are Tools and Equipment, Mobile Generator and Crane borer expenditure are also reported separately per requirement. All other Non-Network other capital expenditure is reported as Other Non-Network Expenditure Fleet.
4. The Complete Fleet list was obtained from the Fleet Intelligence Portal, including historical fleet disposals (sales). This report was used to determine the number of fleet in each category as at 30 June 2021.

5. The Annual Performance (AP) RIN report was obtained to balance off the Fleet, Tools and Equipment Capital Expenditure.

The output was then balanced back against the Non-Network Fleet and Tools capex costs which are captured and reported against the relevant S4 Functional Areas for Fleet.

A 'Non-Network Capex allocation by expenditure type' template determined during the budget process for 20-21 FY which is closely aligned to the proportions of how actual work is carried out, is the shared cost percentage for each of the DNSP (total fleet and tools capex budget).

Based on the budgeted Non-Network Capex allocation by expenditure type' template, the Ergon DNSPs CAPEX costs is further broken down to SCS portion of Non-Network Fleet and Tools Capex.

Buildings and Property, Other

Capex:

All non-network property capex costs are captured and reported against S4 Functional Areas:

- 800036 - CAPEX NN Buildings
- 800037 - CAPEX NN Buildings Lease
- 800038 - CAPEX NN Fixt & Fittings
- 800041 - CAPEX NN Land.

A 'Non-Network Capex allocation by expenditure type' template, prepared by Financial Planning, is the basis for calculating the SCS allocation for Non-Network Property Capex.

The purpose of this template is to separate the CAM workpaper budget allocation assumptions into the capital expenditure types to support the FY21 RIN reporting requirements. Noting that these allocation ratios incorporate any direct attribution that has been applied in the budget.

Based on the budgeted CAM calculations, the direct attribution and shared cost percentage for the DNSP is calculated (budget DA + shared / total property capex budget).

This percentage is then applied to the property capex actuals. The total calculated is then allocated to services based on the budgeted CAM percentages to calculate the SCS amount.

Opex:

All non-network property opex costs are captured and reported against S4 Functional Area 900007 - Indirects NN Property.

These costs are captured as a 'pool' of NN opex against company code 1000 – Energy Queensland Ltd and not against the specific DNSP's (Ergon Energy & Energex).

S4 report 'FIC3018 Regulatory Model (S4 adjusted for regulatory adjustments) is run for the financial year with the parameter of Functional Area 900007.

The total is filtered to exclude GL Code 942012 NN Allocation Property which is the GL code used to allocate NN Property opex to services.

The percentages of total Non-Network Opex allocated to each of the entities is calculated and these percentages are used to allocate the total Non-Network Property Opex pool to the entities.

The SCS percentage is applied to the allocated Non-Network Property Opex for each DNSP.

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.

Refer to the methodology used for Motor Vehicles.

Motor Vehicles

If expenditure is directly attributable to an expenditure category in this RIN Template 2.6 it is a Direct Cost for the purposes of this RIN Template 2.6. Report all capex and/or Opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories.

In RIN Table 2.6.1, in relation to the Non-network Other expenditure category, if Ergon has incurred $1 million or more (nominal) in capital expenditure for a given type or class of assets (e.g. Mobile generators), Ergon has inserted a row in the RIN Template and report that item separately.

There have also been additional categories introduced where Energex has reported categories that was not included in the Ergon DNSP Other expenditure category in previous years, even though the incurred costs are less than $1 million.

Ergon has nominated, and reported separately, expenditure for the following Service Subcategories and Asset Categories.

- Other: Mobile Generator
- Other: Fleet plant & Equipment.

Category - Car

The AER defines a Car as Motor Vehicles other than those that comply with the definition of Light commercial vehicle, Heavy commercial vehicle, and Elevated work platform (LCV) or Elevated work platform (HCV).

Category - Light Commercial

The AER defines Light commercial vehicles (LCVs) as Motor Vehicles that are registered for use on public roads excluding elevated work platforms that:

- are rigid trucks or load carrying vans or utilities having a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes.

or have cab-chassis construction, and a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; or are buses with a gross vehicle mass not exceeding 4.5 tonnes.

Category - EWP

The AER defines Elevated work platforms (HCV) as Motor Vehicles that have permanently attached elevating work platforms that would be HCVs but for the exclusion of elevated work platforms from the definition of HCV.

Category - Heavy Commercial Category

The AER defines Heavy commercial vehicles (HCVs) as Motor Vehicles that are registered for use on public roads excluding Elevated Work Platform (HCV s) that:

- have a gross vehicle mass greater than 4.5 tonnes or
- are articulated Vehicles; or are buses with a gross vehicle mass exceeding 4.5 tonnes

Category - Crane Borer Plant HCV

- Energy Queensland defines crane borer (HCVs) as Motor Vehicles that can carry a power pole, bore holes and lift power poles.
- A 5/10-15 Crane Borer is a maximum 23t GVM 6x4 truck that carries a single power pole.
- The crane component is capable of lifting 5t at 10M extension and can lift 1.5t to 15M in height.
- The auger motor can drill holes up to 3.2M in depth.

Category - *Other Fleet Assets*

The AER defines Non-Network Other Expenditure as all expenditure directly attributable to the replacement, installation, maintenance and operation of Non-network assets, excluding Motor Vehicle assets, Building and Property assets and IT and Communications assets and includes:

- non road registered motor vehicles; non road motor vehicles (e.g. forklifts, boats etc.);
- mobile plant and equipment; tools; trailers (road registered or not); and

- elevating work platforms not permanently mounted on motor vehicles, and mobile generators.

Assumptions

Non-Network Fleet - OPEX

All effort contributed in the Fleet support functions and its associate indirect costs, are closely aligned to the maintenance costs incurred for the maintenance of each fleet category.

CAPEX

No assumptions were made in collating this information.

Estimated Information

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

Explanatory Notes

Not applicable.

Table 2.6.2 - Annual Descriptor Metrics - It & Communications Expenditure

Compliance with the 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 2.6.2 - Annual Descriptor Metrics- IT & Communications Expenditure

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

- 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.

Sources

Actual Information was sourced from:

- SAP FIR3024 FTE Report
- Software compliance reports For User numbers
- Microsoft Active Directory report for User numbers
- System Centre Configuration Manager (Auto discover) and Active Directory for Number of devices.

An SCS percentage was applied to underling data extracted. The SCS percentage was sourced from Template 2.10A Overheads template (refer Basis of Preparation for Template 2.10A).

Methodology

Employee numbers were sourced from the FTE report.
On the 1 July 2018, employees of the distribution network service providers Ergon Energy and Energex were 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 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 reflect 50% of EQL’s (excluding unregulated) employees. An SCS percentage was then applied. The SCS percentage was sourced from Template 2.10A Overheads template (refer Basis of Preparation for Template 2.10A).

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.

Field Force Automation (FFA) user accounts have been excluded to avoid them being duplicated.

An SCS percentage was applied to all source data to meet requirements of the RIN. The SCS percentage was sourced from Template 2.10A Overheads template (refer Basis of Preparation for Template 2.10A).

Assumptions

The employee numbers reported in this RIN reflect 50% of EQL’s (excluding unregulated) employees. An SCS percentage was then applied. The SCS percentage was sourced from Template 2.10A Overheads template (refer Basis of Preparation for Template 2.10A)

Estimated Information

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

Explanatory Notes

Not applicable.

Table 2.6.3 - Annual Descriptor Metrics - Motor Vehicles

Compliance with the 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 2.6.3, in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Sources

- EQL Full Fleet Listing at 30 June 2021
- B-FN-FA-0008 Asset Retirements
- B-FN-FA-0007 Asset Additions
- Average kms per vehicle category & Units held at end of year data sources from the EQL Fleet Tableau data base.

Methodology

Vehicle Annual Descriptor

Ergon applied the following approach to obtain the required information for Non-Network Fleet Annual Descriptor Metrics 2020-21:

Annual kilometres:

- Annual kilometres were calculated using the reported kilometres of all vehicles which were active during the financial year sourced from the EQL Fleet Tableau database
- The vehicles were split into the asset categories and the kilometres totalled. The average was obtained from dividing the total kilometres by the number of vehicles
- Total number annual kilometres by fleet category is then consolidated with the total number Annual kilometres in Ergon and Energex to establish an EQL the total Annual kilometres position
- This is then split into the Energex and Ergon DNSPs based on the 'Non-Network Capex allocation by expenditure type' template used for the 2020-21 CAM allocation

Units Purchased:

- The units purchased were based on vehicles delivered in 2020-21 FY. This was sourced from the EQL Fleet list at 30 June 2021 sourced from the Fleet Intelligence portal.
- Additions are confirmed with the Fixed Asset register and anomalies are discussed with the Program Delivery team.
- Units purchased are then consolidated with the units purchased in Energex to establish an EQL purchased fleet position.

- This is then split into the Energex and Ergon DNSPs based on the 'Non-Network Capex allocation by expenditure type' template, used for the 2020-21 CAM allocation.

Number in Fleet:

- Obtained the Fleet Units on a month by month basis and have averaged over the financial year as per appendix F of the CA RIN (Definitions) which defines that the Number in Fleet should be the average of the units across the financial year.
- Total number in fleet units by fleet category is then consolidated with the number in fleet units in Ergon and Energex to establish an EQL number in fleet position.
- Fleet is only considered as a unit once the asset is in service and has a status in the Fleet Asset register as an In-Service asset.
- This is then split into the Energex and Ergon DNSPs based on the 'Non-Network Capex allocation by expenditure type' template, used for the 2020-21 CAM allocation.

Proportion of total fleet expenditure allocated as regulatory expenditure (%)

- The percentage was determined by A 'Non-Network Capex allocation by expenditure type' template, used for the 2020-21 CAM allocation. This is the basis for calculating the SCS component of the metrics.
- The direct link between CAPEX and units purchased has resulted in the selection of the Non-Network Fleet Capex allocation of services to be used for to determine the units against SCS.
- Each vehicle category was assigned the same percentage, as the actual fleet data could not be allocated to the individual service classification.

Assumptions

Each vehicle category was assigned the same percentage, as the actual fleet data could not be allocated to the individual service classification.

Leased units are excluded as they are not owned by the Ergon DNSP.

Estimated Information

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

Explanatory Notes

Not applicable.

BoP - 2.7 Vegetation Management

Table 2.7.1 - Descriptor Metrics by Zone

Compliance with the 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 and 3.

Sources

All information is sourced from 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.

Methodology

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.

Total route line length is sourced from Smallworld. Ergon Energy identifies Vegetation zones that are inspected in a FY and the total route line length only for the Vegetation zones 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.

Length of Vegetation Corridors

Urban areas are considered not to have vegetation corridors and for rural areas, the length of vegetation corridors is equal to length of 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 taken from the Ellipse database.

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.

Assumptions

Not applicable.

Estimated Information

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

Explanatory Notes

Not applicable.

Table 2.7.2 - Expenditure Metrics by Zone

Compliance with the 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 and 3.

Sources

All information is sourced from SAP Model FIC3013: Ellipse GL Transactions (Regulatory) 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.

Methodology

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.

Assumptions

Not applicable.

Estimated Information

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

Explanatory Notes

Not applicable.

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

Compliance with the 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 and 3.

Sources

Information is sourced from FeederStat and Sap Fiori.

Methodology

All recorded incidents which involve fire come from FeederStat and Sap Fiori. Customer Call data from Feederstat is analysed for jobs where fire was initiated by vegetation. Field crew incidents raised in Sap Fiori are analysed for jobs where fire was initiated by vegetation.

Assumptions

Not applicable.

Estimated Information

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

Explanatory Notes

Not applicable.

BoP - 2.8 Maintenance

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

Compliance with the 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.

Sources

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

- Smallworld GIS
- Ellipse ERP.

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
- Asset Av Age - Smallworld GIS and Ellipse
- Inspection and Maintenance Cycle - Standard for Preventive Maintenance.

Asset Quantity for the Period for SCADA

See section Age Profiles (SCADA, Master Station Assets, Field devices and AFLC) and RTU and Local Master Station Assets (part of Field Devices) from BOP CA 5.2.

Methodology

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.

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

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.
- The Asset Quantity Inspected/Maintained for Pole tops and overhead lines was found to have an error in 2018-19. The amount reported was 981,089 but should have been equal to the asset quantity at year end of 968,754.

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 2020-21 asset age profiles and progress them by the average age.

For Pole Tops and Overhead lines, same method as 2020-21, 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 2020-21, 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 endeavours 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.

Assumptions

Refer to Section Methodology for assumptions applied.

Estimated Information

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

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. Ergon Energy has used suitable collation of actual figures from Ellipse to produce best endeavours estimates.

Explanatory Notes

Not applicable.

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

Compliance with the 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 2.8.2 - Cost Metrics for Routine And Non-Routine Maintenance

Routine Maintenance Expenditure

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.
- Since 2018-19, the costs and quantities for ROAMES were included in Table 2.8 Routine 1a. POLE TOPS AND OVERHEAD LINES aligning treatment for EQL DNSPs (Energex and Ergon Energy). The 2017-18 year was the last time ROAMES costs and quantities were reported in Table 2.7 Vegetation Management.

Sources

Routine Maintenance Expenditure

All information for Routine Maintenance is sourced from Ergon Energy corporate systems namely B-FN-AC-0321-Work Order Analysis PROD 20200508.

Methodology

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.

Non-Routine Maintenance Expenditure

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.

Sources

Non-Routine Maintenance Expenditure

Estimated information for Non-Routine Maintenance was sourced from Ergon Energy's core systems: B-FN-AC-0321-Work Order Analysis PROD 20200508.

Methodology

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.

Assumptions

Non-Routine Maintenance Expenditure

Refer to Section Methodology for assumptions applied.

Estimated Information

Non-Routine Maintenance Expenditure

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

Explanatory Notes

In conjunction with Digital Division in Finance & Corporate Services a workbook has been created to automate the RIN categorisation of transactions and perform adjustments as required. This approach presents a concise view of the cost expenditure performed against maintenance activities.

The developed template categorises general ledger transactions into RIN categories based on a set of criteria as outlined in the Assumptions below.

Once the transactions have been sourced with the desired criteria, they are allocated to the appropriate RIN category allowing us to obtain the actual dollar value of expenditure for each category.

A detailed view of the Maintenance Activity and Asset Category combinations can be found on the ‘Configuration Tab’ of the workbook, including corresponding activity codes, Standard Job Codes, Routine/Non-Routine categorisation, and percentage of apportionment.

As the values for 2.8.2 are also utilised in completing table 2.12 in Rosetta, the Expenditure Type associated with the Work Order transaction has been categorised into relevant RIN categories of: Direct Material Expenditure; Direct labour Expenditure; Contract Expenditure and Other Expenditure.

Maintenance Activity transactions are sourced from the General Ledger Coordinates with the following values:

Activity Codes: 54180; 54100; 53180; 53160; 53150; 53140; 53135; 53135; 53130; 53120; 53100; 52190; 51280; 52170; 52160; 52150; 52140; 52135; 52130; 52120; 52100; 53190

Expense Element: !8100; !7000; !7015; !7060; !7055

District Code: EECL

Posting Date: 2020-06-01

Posting End Date: 2021-07-18

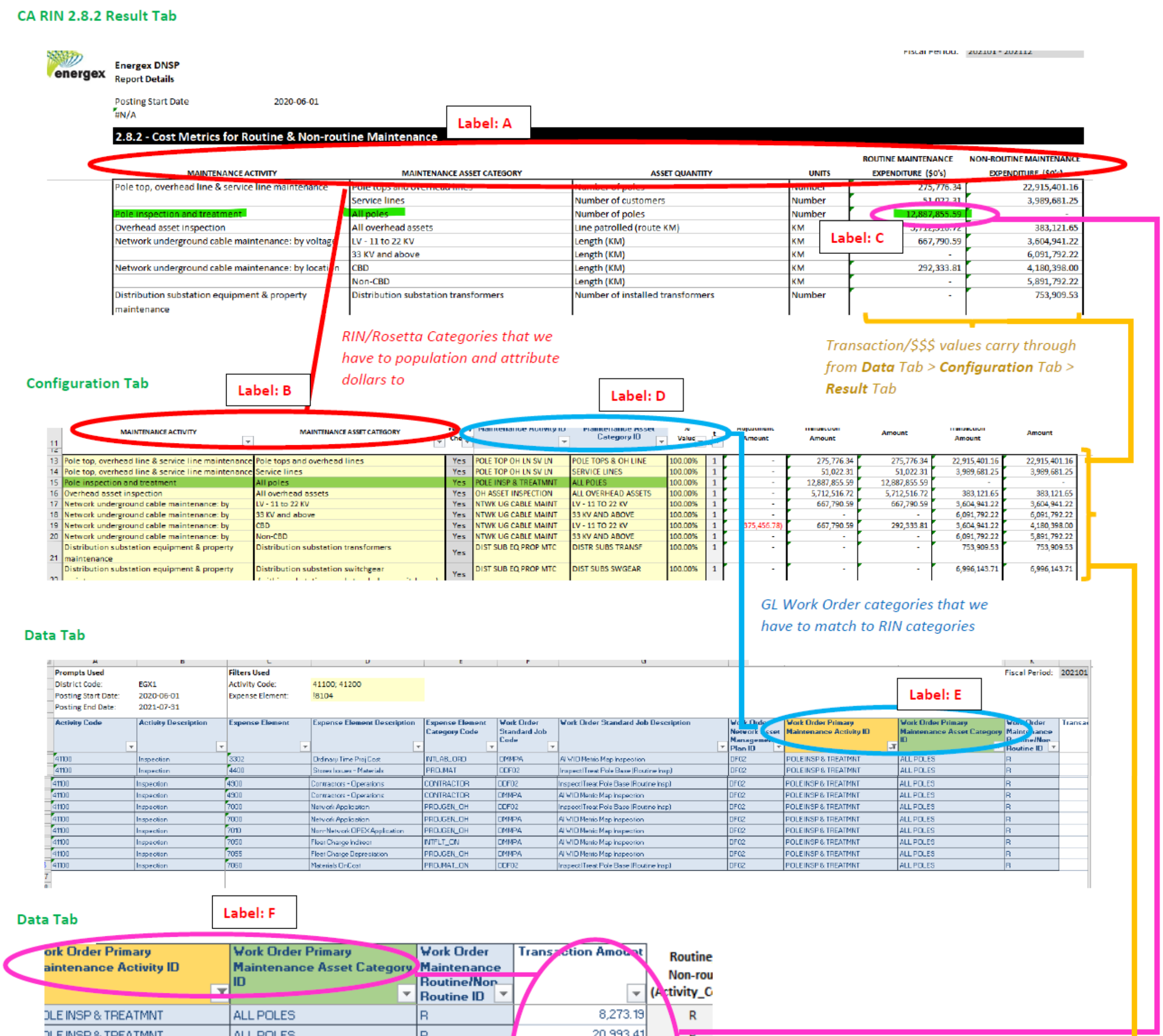
Once the transactions with the above criteria have been sourced, they are categorised based on the combinations set in the ‘Configuration Tab’.

As the general ledger transactions have the dollar value associated, the need for estimating the dollar value has been removed.

The screenshots of the workbook illustrate the linkages of the data as well as how the values are established – as described with the labels:

*This file has been provided as a standalone document.

Label ID	Description/Explanatory Note
A	Workbook location: Results Tab The Results tab summaries the dollar amounts of transactions against the specified RIN categories. The headings on this tab mirror the headings in Rosetta following the same format for ease of understanding.
B	Workbook location: Configuration Tab This tab is where the RIN category combinations that we want to identify in our data (General Ledger transactions) are set – shaded yellow areas are an indication that the fields can be formatted. The Maintenance Activity and Maintenance Asset Category fields are RIN categories that are used as headings in the Results tab.
C	Workbook location: Configuration Tab Label C is the same value as Label F – the dollar value of each transaction as sourced from Ellipse
D	Workbook location: Configuration Tab Same headings as Label E Maintenance Activity ID and Maintenance Asset Category ID – these headings mirror the Work Order Primary Maintenance Activity ID and Work Order Primary Maintenance Asset Category ID from the Data tab.
E	Workbook location: Data Tab Same headings as Label D Work Order Primary Maintenance Activity ID and Work Order Primary Maintenance Asset Category ID These categories are directly from Ellipse, as fields used in work orders. As they do not match the set RIN categories, they are matched to the RIN categories on the Configuration tab. You can see Label D categories have been aligned with to Label B categories through manual allocations.
F	Workbook location: Data Tab The transaction amount from the general ledger This tab hosts general ledger transactions, as sourced by: FIC3013: Ellipse GL Transactions (Regulatory) These figures are attributed to the Results tab as a sum the values per category as defined on the Configuration tab



Assumptions

Within the workbook a function has been included to allow for a percentage of apportionment of funds of a combination of Activity Codes and Work Order Standard Job Codes, to different RIN categories (determined by Maintenance Activity + Maintenance Asset Category), if required. The allocations have been based on historical submissions, for example:

The expenditure value of transactions posted to Activity Code 53120 and WO Standard Job Code SWFR needs to be to 9 different RIN categories. The workbook accounts for this by attributing the expenditure allocation into percentages against the relevant RIN categories (based on historical attributions).

Ergon Energy
CA RIN 2.8.2 Cost Metrics for Routine & Non-routine Maintenance - Configuration

Posting Start Date 2020-06-01
Posting End Date 2021-07-18

TRUE

CA RIN 2.8.2 Cost Metrics for Routine & Non-routine Maintenance - Configuration

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY	Validity Ch	Responsibility Cod	Activity Code	WO Standard Job Cod	Routine/ Non-rout Over-ri	Rout/ No	% Value	Adj't R	Adjustment Amount	Transaction Amount
Pole top, overhead line & service line maintenance	Pole tops and overhead lines	Yes	All	53120	SWFR		N	80.0%		-	
Pole top, overhead line & service line maintenance	Service lines	Yes	All	53120	SWFR		N	4.0%		-	
Pole inspection and treatment	All poles	Yes	All	53120	SWFR		N	2.0%		-	
Overhead asset inspection	All overhead assets	Yes	All	53120	SWFR		N	2.0%		-	
Network underground cable maintenance: by voltage	LV - 11 to 22 KV	Yes	All	53120	SWFR		N	2.0%		-	
Distribution substation equipment & property	Distribution substation transformers	Yes	All	53120	SWFR		N	2.0%		-	
Distribution substation equipment & property maintenance	Distribution substation switchgear (within-substations and stand-alone switchgear)	Yes	All	53120	SWFR		N	2.0%		-	
Distribution substation equipment & property	Distribution substation - other equipment	Yes	All	53120	SWFR		N	5.0%		-	
Distribution substation equipment & property	Distribution substation - property	Yes	All	53120	SWFR		N	1.0%		-	

CA RIN 2.12 Input Tables - Routine & Non-routine Maintenance - Configuration

Where a combination of Activity Code and WO Standard Job Code transactions only need to be attributed to 1 RIN category (determined by Maintenance Activity + Maintenance Asset Category), the % Value is at 100% as per the screenshot below:

CA RIN 2.8.2 Cost Metrics for Routine & Non-routine Maintenance - Configuration

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY	Validity Ch	Respons-ibility Cod	Activity Code	WO Standard Job Cod	Routine/ Non-rout Over-ri	Rout/ No	% Value	Adj't R	ROUTINE MAINTENANCE Adjustment Amount	Transaction Amount	Amount
Distribution substation equipment & property maintenance	Distribution substation switchgear (within-substations and stand-alone switchgear)	Yes	All	52120	AIA1X		R	100.0%	1	-	2,184,700.15	2,184,700.15
Ground clearance - access tracks	Access tracks	Yes	All	52160	AIATX		R	100.0%	1	-	-	-
Ground clearance - access tracks	Access tracks	Yes	All	52160	AIATXC		R	100.0%		-	306,172.46	306,172.46
Ground clearance - access tracks	Access tracks	Yes	All	52160	AIATXF		R	100.0%		-	107,975.67	107,975.67
Ground clearance - access tracks	Access tracks	Yes	All	52160	AIATXN		R	100.0%		-	211,993.93	211,993.93
Ground clearance - access tracks	Access tracks	Yes	All	52160	AIATXS		R	100.0%		-	226,458.55	226,458.55
Ground clearance - access tracks	Access tracks	Yes	All	52160	AIATXW		R	100.0%		-	253,423.63	253,423.63
Pole inspection and treatment	All poles	Yes	All	52120	AIAUDT		R	100.0%	1	-	-	-

Estimated Information

Ergon Energy has provided actual information in Table 2.8.2 for Routine Maintenance Expenditure. Ergon Energy has provided estimated information in Table 2.8.2 for Non-Routine Maintenance Expenditure.

Explanatory Notes

The creation of workbook 2.8.2 Cost Metrics for Routine & Non-Routine Maintenance originated due to several factors including:

- Merger alignment of Ergon Energy and Energex
- SAP DEBBs project moving toward ERP and EIP which provides one source of truth
- The need for more auditable, transparent data

While previous submissions were the result of manual allocations/review of work orders, this work book has automated that process.

BoP - 2.9 Emergency

Table 2.9.1 - Emergency Response Expenditure (OPEX)

Compliance with the 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.

Sources

Actual Information for the variables was sourced from EIP Model FIC3013: Ellipse GL Transactions (Regulatory).

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 EIP Model FIC3013: Ellipse GL Transactions (Regulatory).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 EIP Model FIC3013: Ellipse GL Transactions (Regulatory). 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 EIP Model FIC3013: Ellipse GL Transactions (Regulatory). 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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated Information

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

Explanatory Notes

Not applicable.

BOP - 2.10 Overheads

Table 2.10.1 - Network Overheads Expenditure

Table 2.10.2 - Corporate Overheads Expenditure

Compliance with the RIN Requirements

Commencing from 2020-21, Ergon Energy elected to report against Template 2.10(A) Overheads, which collects information in a different way to the original Template 2.10 Overheads, as this is preferrable to the AER. As instructed in Template 2.10 Overheads, Ergon Energy has selected Template 2.10(A) from the drop-down list to elect reporting in the alternative template in lieu of original Template 2.10 Overheads. As Ergon Energy is only required to complete once version of the Overheads templates it maintains compliance with the Category Analysis RIN Notice.

Sources

Not applicable.

Methodology

Not applicable.

Assumptions

Not applicable.

Estimated Information

Not applicable.

Explanatory Notes

Not applicable.

BoP - 2.10 (A) Overheads

Ergon Energy has opted to report overheads using template version 2.10(A) from this financial year.

Table 2.10.1 - Network Overheads Expenditure

Table 2.10.2 - Corporate Overheads Expenditure

Compliance with the 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(A), 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.

Sources

Ergon Energy has sourced data from the FIC3018 SAP Regulatory Model (which is the SAP GL adjusted for regulatory reporting differences). This forms the basis of the workings for the network overhead and corporate overhead tables.

Methodology

The methodology for the FY2021 RIN is a significant departure from previous submissions. The change caters for alignment to EQL CAM methodology and SAP ERP. This has materially changed the metric outcomes for Ergon Energy in comparison to previous years results. Neither the underlying business activities nor the employee labour costing practices have changed.

EQL shared (support) costs are held at the consolidated level from this regulatory period in accordance with the Group's new operating model and as outlined in the approved 2020-25 CAM.

The major indirect cost pools are:

- Network overheads,
- Non-network overheads (ICT, fleet, property and tools/equipment), and
- Corporate overheads.

There are also pools for directly attributable program of work training, and other unregulated indirect costs for Yurika and Retail.

These are all identified in the GL by specific functional areas, FA 900000 – 900020 and 980023-980025 (which is a field in the SAP GL account structure).

The overhead pools are allocated to the business based on the most appropriate cost drivers for those pools in accordance with the CAM. Any over or under recoveries which are not adjusted in the ledger have been included in the workings and allocated accordingly to ensure the requirements of the overhead template are satisfied.

The amounts allocated to opex/capex and SCS/ACS and to unregulated services for each DNSP can be easily identified using specific GL account codes and functional areas. This enables reporting in the categories outlined by the AER to comply with the template.

Some items identified by Ergon Energy as direct costs and reported accordingly in the Annual Reporting (AR) RIN, need to be mapped to Network Overheads for CA RIN reporting. These included Network Operations, Demand Management, Levies, Customer Service, Network Billing and Other Energy Market Services functions including meter reading.

Allocation to Overhead Category

Each cost centre in SAP (previously RC in Ellipse) is mapped to an overhead pool (ie functional area) as listed above based on its function, and then its costs are allocated in accordance with the 2020-25 CAM.

The network overhead pool and the direct costs from the AR RIN which are treated as overheads for CA RIN purposes, are included in the Network overheads table 2.10.1.

The non-network and corporate overhead pools are included in the Corporate overheads table 2.10.2.

Disaggregation across SCS, ACS and Unregulated Services classifications (Ergon Energy has no Negotiated distribution services) is based on the CAM allocations as described above.

Capitalised Overheads

Capitalised overheads have been calculated in accordance with Ergon Energy's current CAM 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

Overhead rates are reviewed throughout the year and adjusted if required to ensure the indirect costs are fully allocated to the appropriate businesses and services. Where an over or under recovery exists at year end, this has been included in the workings and allocated accordingly to ensure the requirements of the overhead template are satisfied.

Assumptions

Not applicable.

Estimated Information

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

Explanatory Notes

Not applicable.

BoP - 2.11 Labour

Table 2.11.1 - Cost Metrics Per Annum

Table 2.11.2 - Extra Descriptor Metrics for Current Year

Compliance with the RIN Requirements

Table 3.1 demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 3.1 – Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Only labour costs allocated to the provision of SCS should be reported in the labour cost sections of RIN Template 2.11. Labour used in the provision of contracts for both goods and services, other than contracts for the provision of labour (i.e. labour hire contracts) must not be reported in these RIN Templates. Ergon Energy must break down its labour data (both employees and labour contracted through labour hire contracts) into the Classification Levels provided in RIN Template 2.11. Ergon Energy must explain how it has grouped workers into these classification levels.	Ergon Energy general ledger (GL) system (SAP/Ellipse) uses account codes to capture Labour transactional information. Only the GL transactional data compliant with CA RIN Labour guidelines is used as the basis of this submission. Ergon Energy Human Resources system data is used to allocate employees hire to the relevant CA RIN labour classifications. The RIN data is identified at employee & assigned the labour classification for that employee. Labour hire is allocated to the labour classification that aligns to the service provided by the labour hire.
Labour related to each classification level obtained through labour hire contracts may be reported separately on separate lines to employee based labour. If Ergon Energy wishes to do this they should add extra lines in the RIN Template below each classification level for which it wishes to separately report labour hire.	Costs related to labour hire have been combined with internal labour per the Labour Classifications in the table. These costs and hours are reported in Ordinary Time.
Quantities of labour, expenditure, or stand down periods should not be reported multiple times across labour RIN Templates. However, labour may be split between RIN Templates (for example one worker could have half of their time allocated to corporate overheads and half of their time to network overheads).	All figures were allocated to the mutually exclusive categories of corporate overheads, network overheads and network direct.
The ASLs for each classification level must reflect the average Paid FTEs for each Classification Level over the course of the year.	ASLs is derived by using Ergon Energy annual average standard cost for each classification level.

Requirements (instructions and definitions)	Consistency with requirements
'Per ASL' values are average values per ASL in each classification level. For example, the average productive work hours per ASL would equal the total productive work hours associated with labour in the classification level divided by the number reported in Annual Totals - ASLs for the classification level (i.e. the number of ASLs in the classification level).	This has been calculated as per CA RIN AER's instructions. For further details please refer to the Assumptions and Methodology sections.
Stand down periods must be reported against the relevant classification level in the RIN Template containing the relevant labour. For example, a stand down of an electrical line apprentice would be reported against the apprentice classification level in the Total network direct internal labour costs RIN Template.	This was calculated as per the AER's instructions from actual Ellipse data.

Table 2.11.1 - Cost Metrics Per Annum

Sources

Ergon Energy SAP general ledger was the source for all financial and hours transactional data required to complete the RIN.

Ergon Energy Ellipse Human Resource system was the source for Stand Down data and Labour Classification data.

Table 3.2 sets out the sources from which Ergon Energy obtained the required information.

Table 3.2 Information Sources

Variable	Source
ASLs	SAP Financial General Ledger & Ergon Energy standard labour assumptions.
Total Labour Cost	SAP Financial General Ledger system.
Average Productive Working Hours per ASL	SAP Financial General Ledger & Ergon Energy standard labour assumptions.
Stand Down Occurrences per ASL	Ellipse Payroll system

Methodology

Information in the Labour RIN Template was based on actual transactions from source systems.

Ergon Energy applied the following approach to obtain the required information:

1. The following data was obtained from SAP/Ellipse GL:

a. Ordinary time and Overtime $ & Hours

b. Ancillary expenses defined as Labour by this RIN. E.g. training, subsidies, workers compensation, etc.

2. The GL Account Code data was allocated to CA RIN Categories.

The classifications are consistent with Energy Queensland Cost Allocation Methodology (CAM) as per below:

Table 3.3 Ergon Energy SAP GL Code Mapping

CA RIN Category	Ergon Energy SAP GL Code Mapping
Corporate Overhead	Corporate Overheads are defined as the following SAP combinations: a. SAP Company Code = 1000 Energy Queensland b. SAP Functional Area Classification = 7 Indirects c. SAP Cost Centre Category = – 5 Corporate – B Non Network ICT – C Non Network Property – D Non Network Tools – E Non Network Fleet This excludes all non SCS related business costs as per RIN guidelines.
Network Overhead	Network Overheads are defined as the following SAP combinations: a. Indirect Costs – SAP Functional Area = Indirects – SAP Cost Centre Category o 1 Logistics o 2 Network Assets o 3 Network Field EGX o Z Network Field Ergon b. Specific SAP SCS Functional Areas defined as Network Overhead by the CA RIN guidelines. This excludes all non SCS related business costs as per RIN guidelines.
Network Direct	Network Direct is defined as the following SAP combinations: a. SAP Functional Area Classification = 5 SCS This includes Opex & Capex work. This excludes all non SCS related business costs as per RIN guidelines.

Labour Categories

Labour Classification was assigned to each individual employee via Ergon Energy HR system data.

- Each combination of HR data for Wage Type, Labour Type & Award type was mapped to a specific CA RIN Labour Classification.
- This combination was identified for every employee.
- The Employee was then allocated to a CA RIN Labour Classification via that combination.

ASL's

ASL are calculated per Labour Classification:

$$\frac{\text{Total Ordinary Time Costs Excluding Redundancy Costs}}{\text{Business assumptions for Available Ordinary Time \$}}$$

This is a change from previous years driven by alignment to EQL methodology and produces different results to previous years.

Average Productive Work Hours per ASL

Average Productive hours per ASL are calculated:

For each Labour Classification:

- Business assumptions for Available Ordinary Time hours
- Less Actual Training hours
- Plus Actual overtime hours incurred

This is a change from previous years driven by alignment to EQL methodology and produces different results to previous years.

Total Labour Costs

Equals the total of labour costs defined as per RIN guidelines.

The review and alignment of the data has meant the inclusion of a wider scope of costs defined as labour comparted to previous submissions.

Stand down Occurrences per ASL

a. Enforced 9-hour breaks are counted as Stand Downs for this RIN.
b. Volume data per employee is provided via Ergon Energy Payroll records.
c. Stand Down Occurrences per ASL:

$$\frac{\text{No. Stand Down Occurrences}}{\text{ASL quantity}}$$

Labour Hire

1. Labour hire data was captured using the specific GL account code for labour hire & allocated to CA RIN Labour Categories.

Assumptions

ASL Labour Category Hourly Rates

The ASL hourly rates are a weighted average of the Energy Queensland system rates used for employee labour costing transactions. This is required as the CA Labour Categories are always a direct correlation to actual Ellipse Labour classes. CA RIN Labour Category is a mix of Ellipse Labour classifications.

The methodology to derive the rates is:

a. Employees by RIN Labour category are identified using HR data (refer Labour Categories section above).
b. The actual system Labour hourly rate for the employees is identified based on their Ellipse system labour classification.

Labour Category	Ordinary Time Rate			Over Time Rate		
	Ergon	Energex	EQLD	Ergon	Energex	EQLD
Administrative	69.4	69.4	69.4	84.9	84.9	84.9
Professional & Managerial	106.6	106.6	106.6	136.2	136.2	136.2
Executive Above Award	154.1	154.1	154.1	225.2	225.2	225.2
Apprentice	53.7	54.5	53.7	72.4	75.0	72.4
Elec Sys Designer Adv	82.7	78.8	82.7	108.1	106.3	108.1
Para Professional	94.7	90.3	94.7	121.0	120.7	121.0
Power worker	70.5	64.7	70.5	96.0	89.6	96.0
System Operator	120.5	126.5	120.5	172.2	178.0	172.2
Supervisor	97.1	95.4	97.1	128.4	127.3	128.4
Technical Serviceperson	86.1	83.7	86.1	116.9	116.4	116.9

c. A weighted average CA RIN Labour Category ASL hourly rate is derived from the pool of employees & their rates mapped to the CA RIN Category.

For each CA RIN Labour Category the pooled average rate is calculated as follows:

(Employee count * Ellipse hourly rate)/Total Employee count

Total CA Labour Category results are as follows:

CA RIN Lab Cat	Employee Counts			Ordinary RATE				Overtime RATE			
	ENERGEX	ERGON	Grand Total	ENERGEX	ERGON	Total	Weighted Avg CA RIN	ENERGEX	ERGON	Total	Weighted Avg CA RIN
Executive		11	11		$1,695	$1,695	$ 154.10		$2,477	$2,477	$ 225.20
Senior Manager	2	65	67	$308	$10,017	$10,325	$ 154.10	$450	$14,638	$15,088	$ 225.20
Manager	46	265	311	$5,284	$32,477	$37,760	$ 121.42	$6,977	$44,014	$50,991	$ 163.96
Professional	513	1,144	1,657	$54,686	$121,950	$176,636	$ 106.60	$69,871	$155,813	$225,683	$ 136.20
Semi Professional Total	776	1,100	1,876	$74,781	$107,957	$182,737	$ 97.41	$95,834	$141,685	$237,520	$ 126.61
Support Staff	401	813	1,214	$27,829	$56,422	$84,252	$ 69.40	$34,045	$69,024	$103,069	$ 84.90
Skilled Electrical Worker	1,012	1,285	2,297	$84,704	$110,639	$195,343	$ 85.04	$117,797	$150,217	$268,013	$ 116.68
Unskilled Worker	132	225	357	$8,540	$15,863	$24,403	$ 68.36	$11,827	$21,600	$33,427	$ 93.63
Apprentice	180	290	470	$9,810	$15,573	$25,383	$ 54.01	$13,500	$20,996	$34,496	$ 73.40

ASL Productive Time

The ASL Productive Time is a weighted average of the Energy Queensland actuals used for employee labour analytics and planning which are derived via historical actual data over a number of years. This is required as the CA Labour Categories are not always a direct correlation to actual Ellipse Labour classes. CA RIN Labour Category is a mix of Ellipse Labour classifications.

The methodology to derive the Productive Time is:

a. Employees by RIN Labour category are identified using HR data (refer Labour Categories section above).
b. The actual Productive Time hours for the employees is identified based on their Ellipse Labour classification Working Hours value.

   In the table below "Working Hours" = CA RIN Productive Hours

EQL Combined Categories	Gross Hours	Public Holiday	Annual Leave	Sick Leave	LSL	Other	Working Hours
Administrative	1,957.5	75.0	143.9	77.1	26.9	149.0	1,485.6
Manager Above Award	2,088.0	72.0	153.7	45.5	27.8	34.3	1,754.6
Professional Managerial	2,088.0	72.0	155.5	64.2	25.6	54.0	1,716.8
Apprentice	1,879.2	72.0	110.3	51.1	0.5	28.5	1,616.8
Elec Sys Designer Adv	1,892.3	72.5	146.3	88.6	23.9	63.0	1,498.0
Para Professional	1,931.4	74.0	156.9	72.0	24.8	31.9	1,571.8
Power worker	1,879.2	72.0	148.0	81.5	50.9	39.4	1,487.4
System Operator	1,905.3	73.0	238.8	76.3	13.6	10.7	1,493.0
Supervisor	1,931.4	74.0	166.4	75.4	31.3	33.8	1,550.5
Technical Serviceperson	1,879.2	72.0	160.7	80.1	21.3	41.8	1,503.2
Ergon Categories	**Gross Hours**	**Public Holiday**	**Annual Leave**	**Sick Leave**	**LSL**	**Other**	**Working Hours**
Administrative	1,957.5	75.0	143.9	77.1	26.9	149.0	1,485.6
Manager Above Award	2,088.0	72.0	153.7	45.5	27.8	34.3	1,754.6
Professional Managerial	2,088.0	72.0	155.5	64.2	25.6	54.0	1,716.8
Apprentice	1,879.2	72.0	110.3	51.1	0.5	28.5	1,616.8
Elec Sys Designer Adv	1,892.3	72.5	146.3	88.6	23.9	63.0	1,498.0
Para Professional	1,931.4	74.0	156.9	72.0	24.8	31.9	1,571.8
Power worker	1,879.2	72.0	148.0	81.5	50.9	39.4	1,487.4
System Operator	1,905.3	73.0	238.8	76.3	13.6	10.7	1,493.0
Supervisor	1,931.4	74.0	166.4	75.4	31.3	33.8	1,550.5
Technical Serviceperson	1,879.2	72.0	160.7	80.1	21.3	41.8	1,503.2
Energex Categories	**Gross Hours**	**Public Holiday**	**Annual Leave**	**Sick Leave**	**LSL**	**Other**	**Working Hours**
Administrative	1,957.5	75.0	143.9	77.1	26.9	149.0	1,485.6
Manager Above Award	2,088.0	72.0	153.7	45.5	27.8	34.3	1,754.6
Professional Managerial	2,088.0	72.0	155.5	64.2	25.6	54.0	1,716.8
Apprentice	1,879.2	72.0	117.1	56.2	0.3	26.0	1,607.6
Elec Sys Designer Adv	1,905.3	73.0	152.3	92.9	61.3	27.9	1,497.9
Para Professional	1,983.6	68.4	162.3	77.2	35.8	29.5	1,610.5
Power worker	1,879.2	72.0	149.9	83.1	23.2	41.1	1,510.0
System Operator	1,957.5	67.5	190.7	98.6	52.0	19.2	1,529.4
Supervisor	2,035.8	70.2	168.7	78.9	38.2	13.8	1,666.0
Technical Serviceperson	1,879.2	72.0	162.9	80.5	26.3	33.1	1,504.3

c. A weighted average CA RIN Labour Category Available time is derived from the pool of employees & their corresponding available time mapped to the CA Labour RIN Category

CA RIN Lab Cat	Employee Counts		Available Time Hours			CA RIN Available Time Hours
	ERGON	Grand Total	ENERGEX	ERGON	TOTAL	
Executive	11	11	-	19,301	19,301	1,755
Senior Manager	65	67	3,509	114,049	117,558	1,755
Manager	265	311	79,275	458,316	537,591	1,729
Professional	1,144	1,657	880,718	1,964,019	2,844,738	1,717
Semi Professional	1,100	1,876	1,251,652	1,705,027	2,956,679	1,576
Support Staff	813	1,214	584,899	1,185,842	1,770,740	1,459
Skilled Electrical Worker	1,285	2,297	1,522,352	1,931,612	3,453,964	1,504
Unskilled Worker	225	357	199,320	334,665	533,985	1,496
Apprentice	290	470	121,633	468,872	590,505	1,256

d. The CA RIN Available time is then reduced by Non SCS & Training hours and increased by per ASL OT to derive SCS Productive hours assumption per CA RIN Labour Category.

The Overtime hours are removed to derive ASL Ordinary Time hours per CA RIN Labour Category.

The Training hours are based on actual training hours.

RIN Category	Weighted Ordinary Available Time hours	SCS %Weighted Ordinary Available Time hours	Add ASL Overtime hours	Less ASL Training hours	CA RIN Productive Hours	CA RIN Ordinary Hours
Executive	1,754.60	1,386.13	-	24	**1,362.13**	**1,362.13**
Senior Manager	1,754.60	1,386.13	2	24	**1,364.09**	**1,362.13**
Manager	1,728.59	1,365.59	0	24	**1,341.95**	**1,341.59**
Professional	1,716.80	1,356.27	7	24	**1,339.23**	**1,332.27**
Semi Professional	1,576.05	1,245.08	70	31	**1,284.37**	**1,214.08**
Support Staff	1,458.60	1,152.29	2	24	**1,130.29**	**1,128.29**
Skilled Electrical Worker	1,503.68	1,187.91	78	50	**1,215.91**	**1,137.91**
Apprentice	1,256.39	992.55	189	372	**809.77**	**620.55**
Unskilled Worker	1,495.76	1,181.65	7	24	**1,164.47**	**1,157.65**

Estimated Information

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

Explanatory Notes

Reporting where relevant labour classifications are unavailable in the Template

Ergon Energy data has produced results for Labour Classifications of which are not listed in the relevant sections of the metric template.

These results have been populated into the metric template as detailed below.

- Within Corporate Overheads & Network Overheads, figures reported for Intern/Junior Staff/Apprentice represent data that would have otherwise been reported as:
  - Skilled Electrical Workers
  - Unskilled Workers
  - Apprentices
- Within Network Directs, figures reported for Skilled Non Electrical Workers represent data that would have otherwise been reported as:
  - Senior Manager
  - Managers
  - Professionals
  - Semi professionals

- Support staff

Table 2.11.2 - Descriptor Metrics for Current Year

Sources

The source data for Table 2.11.2 Descriptor Metrics for Current Year is the same as Table 2.11.1 Cost Metrics Per Annum. This has been detailed above.

Table 3.4 sets out the sources from which Ergon Energy obtained the required information for table 2.11.2.

Table 3.4 Information Sources

Variable	Source
Ordinary Time Hours	Ergon Energy standard assumptions by Labour Classification
Ordinary Time Rate per ASL	Ergon Energy standard assumptions by Labour Classification
Overtime Hours Per ASL	SAP/Ellipse GL Account code transactions
Overtime Rate Per ASL	Ergon Energy standard assumptions by Labour Classification

Methodology

Table 2.11.2 - Extra Descriptor Metrics

The following process was used to calculate extra descriptor metrics for the 2020-21 regulatory year:

1. Ordinary Time Hours Per ASL

For each Labour Classification

Corporate Overhead = (Ordinary Time hours * SCS%) / ASLs

Network Overhead = (Ordinary Time hours * SCS%) / ASLs

Direct Network = Ordinary Time hours / ASLs

This is Ergon Energy standard Ordinary Hours excluding Training hours assumptions.

This is a change from previous years driven by alignment to EQL methodology and produces different results to previous years.

2. Ordinary Time Hourly Rate per ASL

The Ergon Energy business standard hourly rate.

This is a change from previous years driven by alignment to EQL methodology and produces different results to previous years.

3. Overtime Hours per ASL

For each Labour Classification

Corporate Overhead	= (Overtime hours * SCS%) / ASLs
Network Overhead	= (Overtime hours * SCS%) / ASLs
Direct Network	= Overtime hours / ASLs

4. Overtime Hourly Rate Per ASL

The Ergon Energy standard hourly rate.

Assumptions

Refer to assumptions in 2.11.1

Estimated Information

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

Explanatory Notes

Reporting where relevant labour classifications are unavailable.

Ergon Energy data has produced results for Labour Classifications of which are not listed in the relevant sections of the metric template.

These results have been populated into the metric template as detailed below.

- Within Corporate Overheads & Network Overheads, figures reported for Intern/Junior Staff/Apprentice represent data that would have otherwise been reported as:
  - Skilled Electrical Workers
  - Unskilled Workers

- Apprentices

- Within Network Directs, figures reported for Skilled Non Electrical Workers represent data that would have otherwise been reported as:
  - Senior Manager
  - Managers
  - Professionals
  - Semi professionals
  - Support staff

BoP - 2.12 Input Tables

Table 2.12 Input Tables

Compliance with the RIN Requirements

Table 4.1 demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 4.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Direct costs Operating or capital expenditure directly attributable to a work activity, project or work order. Consists of inhouse costs of direct labour, direct materials, contract costs, and other attributable costs. Excludes any allocated overhead.	Ergon Energy has reported all direct costs in accordance with the categories specified in RIN Table 2.12, which balance to the regulatory accounts where applicable.
Direct materials Materials are the raw materials, standard parts, specialised parts and sub-assemblies required to assemble or manufacture a network/non-network asset or to provide a network/non-network service. Direct materials costs are attributable to a specific asset or service, cost centre, or work order, and exclude materials provided under external-party contracts. Includes: • the cost of scrap • normally anticipated defective units that occur in the ordinary course of the production process • routine quality assurance samples that are tested to destruction • the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	Refer above.
Direct labour cost Labour cost attributable to a specific asset or service, cost centre, work activity, project or work order. Labour costs The costs of:	Refer above.

• Labour hire; and • Ordinary time earnings; and • Other earnings, on-costs and taxes; and • Superannuation.	
Contract A legally binding contract.	Refer above.

Table 4.2 demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 4.2 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Related Party In relation to Ergon Energy, any other entity that: • had, has or is expected to have control or significant influence over Ergon Energy; • was, is or is expected to be subject to control or significant influence from Ergon Energy; • was, is or is expected to be controlled by the same entity that controlled, controls or is expect to control Ergon Energy —referred to as a situation in which entities are subject to common control; • was, is or is expected to be controlled by the same entity that significantly influenced, influences or is expected to influence Ergon Energy; or • was, is or is expected to be significantly influenced by the same entity that controlled, controls or is expected to control Ergon Energy; but excludes any other entity that would otherwise be related solely due to normal dealings of: • financial institutions; • authorised trustee corporations as prescribed in Schedule 9 of the *Corporations* • *Regulations 2001 (Cth);* • fund managers; • trade unions; • statutory authorities; • government departments; • local governments and includes Ergon Energy Limited (ACN 078 849 055); or	Ergon Energy has reported all relevant related party costs reported in the regulatory accounts in accordance with the categories specified in this CA RIN Table. Note that as a consequence of the Queensland Energy Consolidation on 30 June 2017, Ergon Energy, Ergon Energy and Energy Queensland have become more closely related and are required to make associated related party disclosures for RIN reporting.

Where any of the entities identified in subparagraphs (a) to (e) have novated< or assigned a contract or arrangement to or from another entity (where that contract or arrangement relates to the provision of distribution services by Ergon Energy, the entity to whom that contract or arrangement has been novated or assigned.	
Related party contract A finalised Contract between Ergon Energy and a Related Party for the provision of goods and/or services.	Refer Above
Related party margin The dollar amount of profit a Related Party gains above its total actual costs under a Related Party Contract with Ergon Energy. This profit may include margins, management fees or incentive payments.	Ergon Energy has reported all relevant related party margins in the regulatory accounts in accordance with the categories specified in this CA RIN. The dollar amount of profit a Related Party gains is the total actual costs under a Related Party Contract with Ergon Energy. This profit may include margins, management fees or incentive payments.

Sources

Table 4.3 sets out the sources from which Ergon Energy obtained the required information.

Table 4.3 - Information Sources

Expenditure Category	Source
Vegetation management	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Routine maintenance	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Non-routine maintenance	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Overheads	FIC3018 – SAP GL Regulatory model Using GL Hierarchy level 04 Name for mapping
Augmentation	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Connections	FIC3013 – Ellipse GL Regulatory model

	Using Expense element category code for mapping
Emergency response	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Public lighting	FIC3018 – SAP GL Regulatory model Using GL Hierarchy level 04 Name for mapping
Metering	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Fee-based services	FIC3018 – SAP GL Regulatory model Using GL Hierarchy level 04 Name for mapping
Quoted services	FIC3018 – SAP GL Regulatory model Using GL Hierarchy level 04 Name for mapping
Replacement	FIC3013 – Ellipse GL Regulatory model Using Expense element category code for mapping
Non-network expenditure	FIC3018 – SAP GL Regulatory model Using GL Hierarchy level 04 Name for mapping

Expenditure Type	Source	
Related Party	SPARQ	ICT services were previously provided by a related third party ("SPARQ Solutions") and an asset service fee and operational charge was treated as an operating cost in Ergon Energy/Ergon Energy. This cost formed part of the general overhead pool which was allocated to the program of work under the CAM applicable at that time. From 2020-21, organisational changes have resulted in ICT services being provided in-house and the capital and operating costs are now allocated under the 2020-25 CAM. As a result, there will be no related party ICT costs reported and the actual ICT capex will be included in the respective RAB's and operating costs will be recorded in OPEX or overheads as applicable and allocated based on the CAM.
	Ergon Energy	An Ellipse system entry of Ergon accounts payable transactions and intercompany transactions with Inter District Indicators (IDIs). Margin amount is provided by the relevant department.

	Energy Queensland	FIC3018 SAP GL regulatory model extract of transactions. There are no margins between Ergon Energy and Energy Queensland.	
	Yurika Group	Intercompany transactions with Inter District Indicators (IDIs). Margin amount is provided by the relevant Yurika department.	

Methodology

The underlying data for each of the individual CA RIN templates was mapped to the relevant labour, materials, contractor, other category using ellipse expense element or SAP GL account code and reconciled between the input tables and those individual templates.

Assumptions

Replacement

In Template 2.2 Replacement, the difference between the project ledger and general ledger of $9,684,439 is reported in “Other non-AER Asset Categories”. This immaterial difference of 0.26% is reported against the expenditure category ‘other’ in Template 2.12 Input Tables and allocated to direct material cost, direct labour cost, contract cost, and other expenditure based on the cost attribution and allocation in the general ledger for Other DNSP defined categories.

In Template 2.2 Replacement, pole nailing related expenditure that is captured in the project ledger against all AER Replacement expenditure categories was reallocated to the ‘Pole Nailing’ category to comply with AER defined terms. In Template 2.12 Input Tables, the movements have been allocated to direct material cost, direct labour cost, contract cost, and other expenditure based on the cost attribution and allocation in the general ledger for each AER or DNSP defined category.

Estimated Information

Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to all variables contained in this Template. Ergon Energy is transitioning to an automated solution to report Input Tables directly from source systems. In 2020-21, we progressed to an advanced stage of development for this reporting solution. Once final reviews of general ledger account mappings can be verified against RIN instructions and definitions this will conclude our accuracy review. From 2021-22, Ergon Energy anticipates Input Tables can be reported as actuals (subject to audit).

Explanatory Notes

Ergon Energy adopts a booking practice whereby inventory / materials that are returned to stores are credited back to a standard maintenance work order. As such, negatives values are reported against non-routine maintenance expenditure categories in Template 2.12 Input Tables as store returns for field work exceeded the issued materials for maintenance in the year.

BoP - 4.1 Public Lighting

Table 4.1.1 - Descriptor Metrics over Year

Compliance with the 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 (2020-21) 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.

Sources

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.

Methodology

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.

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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated Information

Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 4.1.1.

Explanatory Notes

Not applicable.

Table 4.1.2 - Descriptor Metrics Annually

Compliance with the 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 (2020-21) 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 4.1.2 - 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.

Sources

Actual Information for Light Installation, Replacement and Maintenance Expenditure was sourced from SAP Finance module..

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.

Methodology

Total Public Light installation, replacement and maintenance expenditure was calculated by assigning relevant SAP Functional Area Codes against the corresponding RIN sub-category as below:

Business Rules

Public Lighting total cost valuations are based on actuals as recorded in expense accounts only, with additional considerations as follows. Company Code set to 2100

Installation total costs:

- Functional Area: limited to 800021 - SL new installs
- GL Accounts: starting with "00005", but excluding 0000514813 - Assets donated
- GL Accounts: excluding Overheads (0000590000 & 0000590001)
- Business Transaction Type: excluding settlement activity defined by "KOAE"

Replacement total costs:

- Functional Area: limited to 800022 - SL refurbishment
- GL Accounts: starting with "00005", but excluding Overheads (0000590000 & 0000590001)
- Business Transaction Type: excluding settlement activity defined by "KOAE"

Maintenance total costs:

- Functional Area: limited to 100067 - SL corrective, 100069 - SL preventative & 100070 - SL Customer Request
- GL Accounts: starting with "00005", but excluding Overheads (0000590000 & 0000590001)
- Business Transaction Type: excluding settlement activity defined by "KOAE"

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 totalled 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 totalled 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 2020-21 were collated and cross referenced. Work Orders were cleaned where:

- Start dates were before 01-07-20
- 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.

Assumptions

Refer to Methodology for assumptions applied.

Estimated Information

Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 4.1.2 for the period 2020-21

Explanatory Notes

In 2020-21 Ergon Energy commenced reporting all Public Lighting replacement capital expenditure and volumes in Template 4.1 Public Lighting and discontinued recognising this service in Template 2.2 Repex. Historically, where Ergon Energy operationally bundled together Standard Control Services (SCS) and Alternative Control Services (ACS) capex works, Public Lighting was reported in Template 2.2 Repex. This clear separation will reflect the AER service classifications in Attachment 12: Classification of Services in Energex's 2020-25 Distribution Determination for Template 2.2 Repex (SCS) and Template 4.1 Public Lighting (ACS).

For comparative purposes, reporting for Public Lighting replacement capital expenditure and volumes from bundled works is recognised as follows:

Prior to 1 July 2020:

- Template 2.2 Repex
- Table 2.2.1 - Replacement Expenditure, Volumes and Asset Failures By Asset Category
    - Public Lighting By: Asset Type; Lighting Obligation:

From 1 July 2020:

- Template 4.1 Public Lighting
- Table 4.1.2 - Descriptor Metrics Annually
    - Light Replacement

Table 4.1.3 - Cost Metrics

Compliance with the 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 (2020-21) in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and Definitions in Appendix F to the RIN.

Sources

Information is sourced from Ellipse through running of several reports to assist in arriving at a best estimate and the use of Ergon Energy's Public Lighting estimation calculator.

Methodology

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

Average Unit Cost for Major and Minor Light Installation and Replacement for 2020-21

Average unit cost of installation

The average unit cost of street light installations was prepared for the 5 types of standard constructions:

1. Wood Pole Major - the estimated unit cost assumes the wood pole exists and low voltage supply is available. This unit cost was calculated using Ergon Energy's Public Lighting estimation calculator, for labour, materials, and contracted services.
2. Steel Overhead Major - the estimated unit cost includes installation of a new steel pole and provision of a 40 metre span of overhead service. This unit cost was calculated using Ergon Energy's Public Lighting estimation calculator, for labour, materials, and contracted services.
3. Underground Major - the estimated unit cost includes installation of a new steel pole and provision of a 30 metre length of underground supply. This unit cost was calculated using Ergon Energy's Public Lighting estimation calculator, for labour, materials, and contracted services.
4. Wood Pole Minor - the estimated unit cost assumes the wood pole exists and low voltage supply is available. This unit cost was calculated using Ergon Energy's Public Lighting estimation calculator, which includes the costs for labour, materials, and contracted services.

Average unit cost of replacement

The average unit cost of street light replacements was prepared for the 2 types of luminaires (as identified in the assumptions section above). The methods for calculating the estimated unit costs are outlined below:

1. Major Road Luminaire - High Pressure Sodium Major 150W - the estimated unit cost includes the supply and replacement of a luminaire, lamp and photoelectric cell. This unit cost was calculated using Ergon Energy's Public Lighting estimation calculator, which includes the costs for labour, materials and contracted services.
2. Minor Road Luminaire - LED 17W - , the estimated unit cost includes the supply and replacement of a 17W LED luminaire, lamp and photoelectric cell. This unit cost was calculated using Ergon Energy's Public Lighting estimation calculator, which includes the costs for labour, materials and contracted services.

Average Unit Cost for Major and Minor Light Maintenance for 2020-21.

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

- Volume of lamps, luminaires, brackets and poles linked to maintenance.
  - Activity Codes for each period by breakdown into Major/ Minor light type subcategory
- Average cost of lamps, luminaires, brackets and poles linked to maintenance
  - Activity Codes for each period by breakdown into Major/ Minor light type subcategory
  - Volumes of Installed luminaires is based on number of luminaires.
- General Ledger information for the ratio of Material Cost to Direct costs for maintenance 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 maintenance.

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 2020-21 period.

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.

Assumptions

Refer to Section Methodology for assumptions applied.

Estimated Information

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

Explanatory Notes

Not applicable.

BoP - 4.2 Metering

Table 4.2.1 - Metering Descriptor Metric

Compliance with the 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 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 as per Section 16.4 of the RIN requirements.

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

Sources

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 06-07-2021.

Ergon Energy has checked what the difference is to the annual decline in the meter population if the number of days elapsed between counts varies from year to year. In the direct connect meter population the drop between reported count at 6 July 2020 and 6 July 2021 was 8.58%. Meter replacement rate is not constant throughout the year. It is affected by the scheduling of jobs related to meter failed family work, other meter faults and customer triggered upgrades to metering installation.

Methodology

In relation to Single Phase Meter population and Multiphase Meter population, report B-NE-NC0696 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.

Assumptions

Refer to Methodology for assumptions applied.

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 2020-21.

Explanatory Notes

Not applicable.

Table 4.2.2 - Cost Metrics

Compliance with the 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 all 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.

Sources

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 for SC15, SC16, SC17 and SC18 Meter Asset Management Plan (MAMP) categories.
- Meter Testing expenditure was sourced from EIP Model FIC3013: Ellipse GL Transactions based on GL activity/product code, standard job or work order.
- 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 EIP Model FIC3013: Ellipse GL Transactions based on GL activity/product code, standard job or work order.
- Scheduled Meter Reading expenditure was sourced from EIP Model FIC3013: Ellipse GL Transactions based on GL activity/product code, standard job or work order.
- 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. Filename: 2021 06 Mtr Rdg Stats monthly data.xlsx
- 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 EIP Model FIC3013: Ellipse GL Transactions based on GL activity/product code, standard job or work order.
- 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 AR RIN Capex Summary for CA RIN 2020-21 based on Activity Codes mapping.

- Meter Maintenance expenditure was sourced from EIP Model FIC3013: Ellipse GL Transactions based on based on GL activity/product code, standard job or work order.
- 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.

Methodology

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 for other categories has been summed from detail tabs in DMK013 and DMK213 reports of Peace service orders. The alternative explored was a custom SQL query of Peace data from Data warehouse. Service order type, class and subclass are the keys used to categorise jobs into RIN categories in PCE Map tab. The additional criteria applied in the counts on 'CA RIN 4.2.2 cost metrics' tab are to exclude "isolated" feeder class and count only "complete" market outcome status.
- Expenditure has been allocated by a data extract EIP Model FIC3013: Ellipse GL Transactions 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. This year some mapping by work order has been introduced.
- Meter Testing expenditure was extracted from data extract EIP Model FIC3013: Ellipse GL Transactions 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, MMP500, MMP513, MMP516, MMP517, MMP518). In situ testing work order costs were also included from Activity Code 56000.
- Meter Testing volume data is from POW report 2020/2021 actuals completed validated test result. The in-situ meter testing program single phase volume is taken from count of the relevant Process Tracking Jobs (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 data extract EIP Model FIC3013: Ellipse GL Transactions 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 included in the statistics. Self reads, annual reads for scheduled reading purposes have been excluded. Volume is expressed as the count of NMIs although it is noted that the count of meters is a related statistic used by the business. Total includes skipped NMIs.
- Special Meter Reading expenditure is summarised from data extract EIP Model FIC3013: Ellipse GL transactions for activity code 56000 product code 8080 Special Meter Reads and 56200 8048 Re-en reads. Re-en read is a specific service requested by the retailer in addition to re-energisation and therefore is considered a metering service. This year 56000 8475 final meter read expenditure has been added.
- 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 to include re-energisation reads. This is consistent with the definitions in Appendix F and aligns to reporting in T4.4 Quoted Services. This year final meter read service orders are also included.
- 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 "AR RIN Capex Summary for CA RIN 2020-21" 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. Metering work has been

grouped for operational purpose and there is not a one to one correlation with RIN reporting category. Work Orders from Activity Code 53130 were checked for compliance to RIN definition.

- Meter Maintenance volumes summarised from the CA RIN Index for relevant Standard Jobs and service orders for corrective meter maintenance activities. Service orders selected match the type of work included in meter maintenance expenditure

New Meter Installation and Other Metering Expenditure

In relation to New Meter Installation expenditure, Ergon Energy has developed an estimate based on the following approach: The ACS price list has charge rates for Auxiliary metering services "Install new meter" service grouping. This has been used to estimate the cost. This compared with SSW New Connection service order actual "Product" and Charge.

Expenditure for new meter installation is a part of the cost of the new connection works, for which labour, internal transport, tools and plant purchase costs are captured. To use this cost requires apportioning the labour & transport costs and adding the cost of the metering equipment. Instead the method adopted takes in the ACS price from Auxiliary metering services which is determined by type of meter installed, whether it was additional or replacement meter, and the feeder type at each NMI. Jobs for new connections are listed in DMK213 Service Order report which is used to select for new meter installations in POC exempt areas. Additional information is provided by a custom query of Peace data showing product and charges associated with each service order.

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 data extract EIP Model FIC3013: Ellipse GL Transactions based on based on GL activity/product code, standard job or work order. The same data extract EIP Model FIC3013: Ellipse GL Transactions was used to identify the correct category for CAPEX activity C2230.

- Other Metering Type 6 expenditure consists of the totalling 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.

Assumptions

Refer to Section Methodology for assumptions applied.

Estimated Information

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

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

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 work to supply new connection in those areas where Ergon has the role of meter provider. The ACS price list for Auxiliary metering services "Install new meter" service grouping has been used as an estimate of the cost.
- 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.

Explanatory Notes

Not applicable.

BoP - 4.3 Fee-based Services

Table 4.3.1 - Cost Metrics for Fee-based Services

Compliance with the RIN Requirements

Table 5.1 demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 5.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Ergon Energy must ensure that the data provided for fee-based services reconciles to internal planning models used in generating Ergon Energy's proposed revenue requirements.	As advised by the AER in the CA RIN Issues Register (item 74), this requirement does not apply to DNSPs that are not completing reset RINs.
In the RIN Templates 4.3, Ergon Energy must list all the Fee Based services that were listed in the annual tariff proposal of each relevant year.	Ergon Energy has applied this consistency requirement. Fee Based Services with Nil transactions for the year (amount, volume) have been excluded.
In the basis of preparation, Ergon Energy must provide a description of each Fee Based service listed in the RIN Templates 4.3. In each service's description, Ergon Energy must explain the purpose of each service and detail the activities which comprise each service.	Ergon Energy has applied this consistency requirement.
Ergon Energy is not required to distinguish expenditure for Fee Based services between standard or alternative control services in RIN Templates 4.3.	There is no crossover between the services under standard and alternative control services (ACS). Fee Based Services are ACS only.
Ergon Energy is not required to distinguish expenditure for Fee Based as either Capex or Opex in RIN Templates 4.3.	Only operating costs have been reported, no capital expenditure (capex) is captured for fee-based services.

Costs have been measured as the direct cost, excluding overheads.

Sources

Ergon Energy has sourced data from the SAP regulatory model (FIC3018), on the Enterprise Intelligence Platform (EIP) to comply with the AER approved Cost Allocation Method (CAM), as well as Ellipse and PEACE systems, and Quantitative Reporting.

Methodology

Services to be reported

- Ergon Energy's Framework & Approach, Classification of Services, Pricing Proposal and Tariff Schedule were reviewed to determine which services should be classified as Fee-Based from 2020-25.
- Any customer-requested services which are charged via a fixed fee have been reported in Template 4.3 Fee-Based Services.

Expenditure Dollar Values

- Expenditure for the services determined to be Fee-Based were extracted from general ledger reports using ACS expenditure type and included in Template 4.3.

Volume

- 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.

Note: in accordance with Schedule 8 s225, Ergon Energy is unable to charge for disconnection of supply of electricity to premises.

Assumptions

No assumptions have been applied.

Estimated Information

Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 4.3.1.

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 2020-21 year in accordance with Appendix E, Principles and Requirements, paragraph 15.2 of the AER's RIN.

Table 5.2 Fee Based Services

Common and Miscellaneous Services	Purpose/ Activities of each service
Call out fee	Crews attend site at the customers request and is unable to perform job due to customers fault/fault of a third party.

De-energisation	Retailer requested de-energisation of the customer's premises where the de-energisation can be performed at the premises i.e. by a method other than main switch seal (e.g. pole, pillar, transformer or meter isolation link).
Faults/Emergency response	Attending loss of Supply - customer fault.
Install new meter (Type 5 and 6)	Install new meter (Type 5 and 6).
Load control time switch	Change load control equipment (inc. time switch and relay install, modify and removal).
Meter inspection and investigation on request	A request to conduct a site review of the state of the customer's metering installation(s) (no physical meter test), i.e. multiple premises. Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware.
Meter reading	Customer requests a check read, transfer read or validation of an estimated read on the meter, may be due to reported error in the meter reading. This is only used to check the accuracy of the meter reading. Special meter reading including final read. Retailer or customer requested.
Meter reconfiguration	A request to make a change from one tariff to another tariff.
Meter test	Customer requested Meter Accuracy Testing of type 5-6 meter.
Metering alteration	Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment.
Point of attachment relocation	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. This includes De-energisation, followed by physical dismantling then reattachment of service and re-energisation. Excludes work on metering equipment (if required).
Re-arrange connection assets at customer's request	Rearrange connection assets at customer's request - simple (upgrade from overhead to underground where main connection point is in existence). Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer

	requested conversion of existing overhead service to underground service.
Re-energisation	Retailer or metering coordinator/provider requests a visual examination upon re-energisation (physical) of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days.
Removal of a meter (Type 5 & 6)	Removal of Meter.
Request for Temporary Connection for short term supply	Customer requested temporary connection (short term) and recovery of the temporary builder's supply. Note: this service is only available for non-grid connected areas of our network (isolated feeders and the Mount Isa-Cloncurry supply network).
Reseal	Reseal and inspection of meter after customer-initiated work.
Supply Abolishment	Retailer requests Ergon Energy to abolish supply at a connection point and decommission an 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. Overhead or Underground.
Supply enhancement	Service upgrade. For example, an upgrade from single phase to multi-phase and/or increase capacity. Excludes work on metering equipment (if required). Overhead.
Temporary connection	Customer requested temporary connection (short term) and the recovery of the temporary builder's supply. Excludes work on metering equipment.
Temporary disconnections and reconnections (which may involve a line drop)	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the supply will be disconnected.
Type 6 non-standard metering data services	Provision of load profile data where available – Retailer requested.

BoP - 4.4 Quoted Services

Table 4.4.1 - Cost Metrics for Quoted Services

Compliance with the RIN Requirements

Table 5.1 demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 6.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Ergon Energy must ensure that the data provided for quoted services reconciles to internal planning models used in generating Ergon Energy's proposed revenue requirements.	As advised by the AER in the CA RIN Issues Register (item 74), this requirement does not apply to DNSPs that are not completing reset RINs.
In the RIN Templates 4.4, Ergon Energy must list all the quoted services that were listed in the annual tariff proposal of each relevant year.	Ergon Energy has applied this consistency requirement. Quoted Services with Nil transactions for the year (amount, volume) have been excluded.
In the basis of preparation, Ergon Energy must provide a description of each quoted service listed in the RIN Templates 4.4. In each service's description, Ergon Energy must explain the purpose of each service and detail the activities which comprise each service.	Ergon Energy has applied this consistency requirement.
Ergon Energy is not required to distinguish expenditure for quoted services between standard or alternative control services in RIN Templates 4.3.	There is no crossover between the services under standard and alternative control services (ACS). Quoted Services are ACS only.
Ergon Energy is not required to distinguish expenditure for quoted Based as either Capex or Opex in RIN Templates 4.3.	Ergon Energy has applied this consistency requirement.

Costs have been measured as the direct cost, excluding overheads.

Sources

Ergon Energy has sourced data from the SAP regulatory model (FIC3018), on the Enterprise Intelligence Platform (EIP) to comply with the AER approved Cost Allocation Method (CAM), as well as Ellipse and PEACE systems, and Quantitative Reporting.

Methodology

Services to be reported

- Ergon Energy's Framework and Approach, Classification of Services, Pricing Proposal and Tariff Schedule were reviewed to determine which services should be classified as Quoted service from 2020-25.

- Any customer-requested services which are charged via a quoted fee have been reported in Template 4.4 Quoted Services.

Expenditure Dollar Values

- Expenditure for the services determined to be Quoted services were extracted from general ledger reports using ACS expenditure type and included in Template 4.4.

Volume

- Ellipse work orders and Ellipse works requests are counted to calculate the related volumes depending on the service.
- For Large Customer Connections (LCC), the large customer contribution functional areas are identified and summarised by works requests.
- 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.

Assumptions

No assumptions have been applied.

Estimated Information

Ergon Energy has provided Actual Information, in accordance with the AER's definition, for all variables in Table 6..

Explanatory Notes

The Quoted Services in the below Table are reflective of all 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 6.2 Quoted Services description

Quoted Services	Purpose and Activities of Service
Authorisation and approval of third-party service providers design/works	Activities include: • Authorisation or re-authorisation of individual employees and subcontractors of third-party service providers and additional authorisations at the request of the third-party service providers (excludes training services) • Acceptance of third party designs and works • Assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor's approved materials list.

Auxiliary public lighting services	Includes the provision, construction and maintenance of public lighting and emerging public lighting technology.
Connection application and management services	Works initiated by a customer or retailer which are specific to the connection point. Includes, but is not limited to: • connection application related services • de-energisation • re-energisation • temporary connections • remove or reposition connection • overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. as a result of a point of attachment relocation). No material change to load • protection and power quality assessment • supply enhancement (e.g. upgrade from single phase to three phase) • customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g. change protection settings) • upgrade from overhead to underground service • rectification of illegal connections or damage to overhead or underground service cables • calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER • power factor correction.
Customer requested planned interruptions	Examples include: • Where the customer requests to move a distributor planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours • customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach, which impacts other networks users).
Customer requested provision of electricity network data	Data requests by customers or third parties including requests for the provision of electricity network data or consumption data outside of legislative obligations.
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.
Enhanced Connection Services	Other or enhanced connection services provided at the request of a customer or third party include those that are: • provided with higher quality of reliability standards, or lower quality of reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments • in excess of levels of service or plant ratings required to be provided by the distributor, and • for embedded generators, including the removal of network constraints.
Inspection and auditing services	Activities include: • inspection and reinspection by a distributor, of gifted assets or assets that have been installed or relocated by a third party • investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third-party service.
Major Customer – Network Extensions	Means a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by the AER. Network extensions means an enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a network service provider to facilitate: a new or altered major customer connection, where the network extension will be dedicated to the exclusive use of the major customer at the time of installation and energisation and there is no reasonable likelihood that the network extension will be used to supply another customer.
Major Customer – Premises Connections	Means a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by the AER. Premises connections includes any additions or upgrades to connection assets located on the customer's premises for a major customer.

Network related property services	Activities include: • Network related property services such as property tenure services relating to providing advice on, or obtaining deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with a connection or relocation. • Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.
Network Safety Services	Examples include: • provision of traffic control and safety observer services by the distributor or third party where required • fitting of tiger tails and aerial markers • third party request for de-energising wires for safe approach • high load escorts.
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).
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 training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network and to carry out switching on the distributor's network. Examples of training might include high voltage training, protection training or working near power lines training.
Removal/rearrangement of network assets	Relocation of assets that form part of the distribution network in circumstances where the relocation was initiated by a third party (including a customer).
Sale of approved materials or equipment	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network.
Security (watchman) lights	Provision, installation, operation and maintenance of equipment mounted on a distribution pole used for security services, e.g. nightwatchman lights. Note: excludes connection services.

Third party funded network alterations	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to be installed on the shared distribution network. This does not relate to upstream distribution network augmentation.
Third party requested outage for purposes of replacing meter	At the request of a retailer or metering coordinator, provides notification to affected customers, and isolates power at a customer's premises to facilitate the replacement of the existing metering installation by an external metering provider.
Types 5 and 6 meter maintenance, reading and data services	Activities includes: • Meter maintenance covers works to inspect, test, maintain and repair metering installations. It also includes the removal and disposal of a metering installation at customers' premises. • Meter reading refers to quarterly or other regular reading of a metering installation.

BoP - 5.2 Asset Age Profile

Table 5.2.1 - Asset Age Profile

Compliance with the 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.

Sources

Mean Life and Standard Deviation

General industry life expectations, manufacturer's specification and operational experience with the assets have been used as the sources of data for the calculation of the mean life.

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.
- Project documentation on what equipment has been installed

Age Profiles (SCADA, Field devices and AFLC)

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.

- PDS and IPS protection database
- Project reporting (business objects) and Project documentation including substation construction records, stores records
- Manual record keeping (Excel spreadsheet)
- Master station, RTU and HMI configuration files
- Collated project information from project managers and subject matter experts

Age Profiles (Master Station Assets)

- Manual record keeping (Excel spreadsheet)

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.

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-year of manufacture (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.
- Large increase in <=1kv group due to missing conductor data capture event in 2021.
- With the implementation of the UGIS Project, there is a limit on the maximum length a conductor that can be imported into the new system. Conductors in the categories >22KV & <=66KV and >66KV & <=132KV were split into 5km segments or less biased on design standard for strain. This has resulted in the above rules recalculating the age of a number of conductors.

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.

- Large jump in the total Service line Counts Due to the UDMS Project which was trying to ensure that all customers have the correct service line represented in the system.

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.

In category POLE MOUNTED;<=22kV;>600kVA;SINGLE PHASE there has been increase of counts between 1973-1989. This is the result of a data quality event by UDMS project where correct capacity was recorded but incorrect number of transformers which is now resolved.

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.

For current transformers there is an increase in the year 1996 and a drop across other years. This is due to data quality event where manufacture age was corrected in source system.

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 02-07-2015; "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 02-07-2015; "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.

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.

Communications network assets and Communications Site Infrastructure

As we have not completed the updating of our base data in the corporate systems, based on expenditure for financial year 2020-21 we have reported installations calculated by Telecommunications Project Managers & Return To Service (RTS Project) installations. Replacements for financial year 2020-21 have been aligned manually with assets from previous financial years and removed accordingly.

In relation to Age Profile (2020-21), 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 2020-21 for installed assets.
- Make an assumption based on the technology of the assets replaced and SME advice in financial year 2020-21 of where to reduce the asset volume in previous years.

Communications Linear assets

Information was extracted from small world.

Field Devices

Ergon Energy SCADA field devices include asset information in the following categories:

- Protection relays
- Remote Terminal Units and Local Master Station (Human Machine Interface, local control interface)

Protection Relays

Asset Information is prepared by

- 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. Energy has performed a comprehensive site audit and is continuously correcting the protection relay asset data in Ellipse.
- 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 Energy asset ownership/maintenance, and determination of assets that are operational/in-service.

Remote Terminal Units and 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.
- Failed in Service jobs where an RTU or HMI was replaced, cross referenced with warehouse orders.
- Asset age information for these categories are determined by date of install. Where asset age could not be determined, the estimated age of the type and configuration of the asset is used.

AFLC Devices

Ergon Energy AFLC device information is gathered from completed projects and failed-in-service replacements, cross-referenced by commissioning into the Ergon Energy Network Control Master Station. AFLC devices in this category include:

- Load Controller
- Coupling Cell
- Injector

Master Station Assets

In relation to installed assets, Ergon Energy has developed an estimate based on the number of projects that are in implementation or were scheduled for that time period.

A spreadsheet tracks the racked equipment for Townsville and Rockhampton. A list was derived from this spreadsheet and reviewed as to what equipment was master station asset equipment.

As part of the NM Project which installed a new version of the ABB Master Station in 2015/16, some of the existing equipment was kept and the remaining was upgraded for the new version of software. This equipment was purchased by ABB in the USA and then shipped to Australia. The list of this equipment was previously derived based on querying the HP web site for a serial. However, this capability is no longer available. As a result an estimate has been made for those servers in 2015-16 based on subject matter expert knowledge.

Assumptions

Refer to the Methodology Section for any assumptions applied.

Estimated Information

Age Profiles (all except SCADA)

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 disc and 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.

Ergon Energy believes the estimates supplied are the best estimates based on the available information at the time.

Age Profiles (SCADA, Communications Network Assets, Communications Site Infrastructure and Communications linear assets)

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 Communications Network assets and Communications site infrastructure within the SCADA category. No complete current corporate source of data is available. The methodology section details the steps that have been used, and represent the only practical way currently to develop an age profile of these assets. Other options exist however are either not cost effective (state wide audit of all devices recording serial numbers of all equipment and then requesting manufacturing date from suppliers) or would not provide more accurate results than the method used.

As a result, Ergon Energy believes the estimates supplied are the best estimates based on the available information at the time.

Age Profiles (SCADA, Master Station Assets, Field devices and AFLC)

Ergon Energy has provided Estimated Information in relation to the following variables, for all asset categories in the asset groups.

Protection Relay Assets (part of Field Devices)

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.

Ergon Energy believes the estimates supplied are the best estimates based on the available information at the time.

RTU and Local Master Station Assets (part of Field Devices)

It was not possible to provide actual age information for some RTU and Local Master Station (HMI) assets due to incomplete data. Approximately 15% of RTU and HMI age data have been estimated by the relevant SMEs with prior experience and knowledge

Ergon Energy believes the estimates supplied are the best estimates based on the available information at the time.

Explanatory Notes

Not applicable.

BoP - 5.3 MD Network Level

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

Compliance with the 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.

Sources

Actual Information for the variables was sourced from Network Operational Data Warehouse (NODW). 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).

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 November to 1 April while Winter Peak is considered to occur in the period 1 June to 1 September. 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, 2020-21 is the 12-month period ending 01-04-2021 00:00, of which winter MDs are recorded during 2020 and summer MDs are recorded during period 2020-21.
- ***EMBEDDED GENERATION*** is scheduled, semi-scheduled and non-scheduled embedded generation. The data was obtained from NETS/NODW as the aggregation of all measurable embedded generation on the Ergon Energy regulated network at the time of system coincidence. Only those sites where Ergon Energy has 30-minute interval meters installed and recorded are used in this variable, as coincident values cannot be determined for sites without 30 minute interval metering. Micro-embedded generation is "behind the meter" and non-scheduled, and therefore not included in the metric
- ***Weather* Corrected *(10% Poe) Network Coincident MD*, And *Weather Corrected (50% Poe) Network Coincident MD.***
- ***Note:* The interpretation of "Raw Network Coincident MD" is taken to mean the highest metered load for a half hour over the course of a year, including the load offset by the major embedded generators, and as such, the generation total is quoted as a negative number. From 2020, the Weather corrected POE Network Coincident MD figures - do not include the load offset by the major embedded generators.**

In order to obtain weather adjusted peak demand, Ergon Energy has employed a methodology involving:

- Daily maximum and minimum temperatures as well as rainfall 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. The model also simulates the relationship between the regions to produce an Ergon Energy system level demand forecast.
- 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 annual peak demands were analysed / measured 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.

Assumptions

Not applicable.

Estimated 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.

Explanatory Notes

Not applicable.

BoP - 5.4 MD Utilisation Spatial

Table 5.4.1 Non-coincident & Coincident Maximum Demand

Compliance with the RIN Requirements

Ergon Energy has populated all variables for cells where data is available 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 have been left blank or '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.

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

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 irrespective of whether they are wholly owned and maintained by Ergon Energy or not. From 2020 we have included substations where Powerlink owns the transformers, these were previously not included in 5.4.
- 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".
- 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 calculates the substation's parallel rating based on the NCC rating and impedance values of each individual plant item. 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. 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. For substations where it was identified that the non-coincident peak MVA occurred at a different time to the non-coincident peak MW, a separate table is attached showing the non-coincident peak demand in MVA. Refer to Appendix 7 - Maximum Demand and Utilisation Spatial - Peak MVA Differing from Peak MW.
- 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 November to 31 March inclusive while Winter Peak is considered to occur in the period 1 June to 31 August 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, 2020-21 is the 12 month period ending 01-04-2021 00:00, of which winter MDs are recorded during period 01-06-2020 00:30 - 01-9-2020 00:00 and summer MDs are recorded during period 01-11-2020 00:30 - 01-04-2021 00:00.
- ***SHOULDER PERIOD PEAKS -*** If a substation has a significant annual peak outside of the defined summer or winter periods, it would have the peak defined as per the RIN defined "summer" and "winter" periods. No such peaks occurred in 2020-21.
- ***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.

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 bulk supply substation is chosen by its consistency of available weather data from the weather station over an acceptable continuous time period t.

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: coefficients for a multivariate equation using variables of Temperature (Maximum and minimum), Saturday, Sunday, public holidays and the Xmas shutdown 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 multiple 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

Capacity has been estimated by selecting a common transformer size greater than the value recorded in their available peak demand history.

Assumptions

The available peak demand history for the substation is reflective of its transformer size. i.e. the substation's peak demand is not significantly below its rated capacity.

Estimated 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.

Ergon Energy did not have capacity information for a small number of substations with assets owned by customers or Powerlink. As a result, Ergon Energy has estimated the substation rating non-coincident and coincident for those substations.

Ergon Energy did not have capacity information for a small number of substations with assets owned by customers or Powerlink. As a result, Ergon Energy has estimated the substation rating non-coincident and coincident for the following substations:

- Taronga BSP
- Collinsville
- Thalanga Mine
- Several Private substations

Ergon Energy believes the estimates supplied are the best estimate based on the available information at the time.

Explanatory Notes

Maximum Demand and Utilisation Spatial - Peak MVA Differing from Peak MW

Alligator Creek BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	36.22
			MAX MVA	37.70
	DATE MD OCCURRED		NON-COINCIDENT	09/12/2020
			MAX MVA	08/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	1:00:00 PM
			MAX MVA	11:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Barcaldine BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	21.93
			MAX MVA	41.48
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	30/08/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	10:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Broadlea BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	43.68
			MAX MVA	45.52
	DATE MD OCCURRED		NON-COINCIDENT	23/01/2021
			MAX MVA	02/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	9:00:00 PM
			MAX MVA	11:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Bundaberg BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	115.18
			MAX MVA	115.25
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	23/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Chinchilla BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	20.84
			MAX MVA	27.93
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	23/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Daandine BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	6.27
			MAX MVA	13.67
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	10/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	4:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Isis BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	54.42
			MAX MVA	54.92
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	25/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	9:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Kilkivan BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	15.99
			MAX MVA	18.62
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	30/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	7:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Louisa Creek BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	40.77
			MAX MVA	67.34
	DATE MD OCCURRED		NON-COINCIDENT	06/03/2021
			MAX MVA	04/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	2:30:00 AM
			MAX MVA	3:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Maryborough BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	124.66
			MAX MVA	124.86
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	22/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Oakey BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	24.42
			MAX MVA	26.02
	DATE MD OCCURRED		NON-COINCIDENT	30/11/2020
			MAX MVA	30/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:30:00 PM
			MAX MVA	1:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Roma 33kV BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	25.52
			MAX MVA	55.36
	DATE MD OCCURRED		NON-COINCIDENT	03/12/2020
			MAX MVA	30/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:00:00 PM
			MAX MVA	3:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Roma 66kV BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	36.42
			MAX MVA	52.61
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	02/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	1:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
South Toowoomba BSP	RAW ADJUSTED MD	MVA	NON-COINCIDENT	61.48
			MAX MVA	83.20
	DATE MD OCCURRED		NON-COINCIDENT	10/08/2020
			MAX MVA	14/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
Ayr	RAW ADJUSTED MD	MVA	NON-COINCIDENT	9.56
			MAX MVA	9.74
	DATE MD OCCURRED		NON-COINCIDENT	22/12/2020
			MAX MVA	01/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Barcaldine	RAW ADJUSTED MD	MVA	NON-COINCIDENT	7.65
			MAX MVA	10.71
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	23/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	1:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Bedford Weir	RAW ADJUSTED MD	MVA	NON-COINCIDENT	8.12
			MAX MVA	8.68
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	14/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 PM
			MAX MVA	8:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Calliope	RAW ADJUSTED MD	MVA	NON-COINCIDENT	9.33
			MAX MVA	10.33
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	01/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER

Cannonvale	RAW ADJUSTED MD	MVA	NON-COINCIDENT	15.96
			MAX MVA	16.22
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	23/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	5:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Cape River	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.74
			MAX MVA	0.74
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	05/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Cape River East	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.91
			MAX MVA	6.77
	DATE MD OCCURRED		NON-COINCIDENT	03/06/2020
			MAX MVA	15/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	1:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
Charleville	RAW ADJUSTED MD	MVA	NON-COINCIDENT	13.23
			MAX MVA	13.37
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	20/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	4:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Charters Towers	RAW ADJUSTED MD	MVA	NON-COINCIDENT	10.18
			MAX MVA	10.26
	DATE MD OCCURRED		NON-COINCIDENT	07/02/2021
			MAX MVA	04/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Chillagoe	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.43
			MAX MVA	0.46
	DATE MD OCCURRED		NON-COINCIDENT	01/11/2020
			MAX MVA	09/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	1:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Clinton	RAW ADJUSTED MD	MVA	NON-COINCIDENT	13.14
			MAX MVA	14.89
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	08/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:30:00 PM
			MAX MVA	1:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Cloncurry	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.69
			MAX MVA	3.69
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	02/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Collinsville	RAW ADJUSTED MD	MVA	NON-COINCIDENT	12.02
			MAX MVA	12.91
	DATE MD OCCURRED		NON-COINCIDENT	15/12/2020
			MAX MVA	29/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	2:30:00 PM
			MAX MVA	11:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Comet	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.55
			MAX MVA	2.73
	DATE MD OCCURRED		NON-COINCIDENT	13/01/2021
			MAX MVA	25/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:30:00 AM
			MAX MVA	9:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Cooktown	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.97
			MAX MVA	3.99
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	15/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Crediton	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.38
			MAX MVA	0.57
	DATE MD OCCURRED		NON-COINCIDENT	18/03/2021
			MAX MVA	16/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Crows Nest	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.78
			MAX MVA	4.81
	DATE MD OCCURRED		NON-COINCIDENT	14/07/2020
			MAX MVA	14/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
Disraeli	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.13
			MAX MVA	0.13
	DATE MD OCCURRED		NON-COINCIDENT	25/11/2020
			MAX MVA	02/08/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	1:00:00 PM
			MAX MVA	11:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
East Ayr	RAW ADJUSTED MD	MVA	NON-COINCIDENT	14.10
			MAX MVA	15.26
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	17/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	4:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
El Arish	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.69
			MAX MVA	7.89
	DATE MD OCCURRED		NON-COINCIDENT	23/12/2020
			MAX MVA	17/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Ellwoods Road	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.58
			MAX MVA	2.60
	DATE MD OCCURRED		NON-COINCIDENT	03/02/2021
			MAX MVA	02/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	10:30:00 AM
			MAX MVA	2:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Evelyn	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.43
			MAX MVA	2.79
	DATE MD OCCURRED		NON-COINCIDENT	07/11/2020
			MAX MVA	08/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:00:00 PM
			MAX MVA	6:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Farleigh	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.12
			MAX MVA	4.33
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	01/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Farnsfield	RAW ADJUSTED MD	MVA	NON-COINCIDENT	10.67
			MAX MVA	10.68
	DATE MD OCCURRED		NON-COINCIDENT	03/02/2021
			MAX MVA	03/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:00:00 PM
			MAX MVA	8:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Glenden	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.69
			MAX MVA	2.40
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	09/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	4:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Granite Creek	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.31
			MAX MVA	0.93
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	05/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	2:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Greenvale	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.49
			MAX MVA	0.52
	DATE MD OCCURRED		NON-COINCIDENT	24/11/2020
			MAX MVA	06/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Hartley Street	RAW ADJUSTED MD	MVA	NON-COINCIDENT	52.66
			MAX MVA	57.74
	DATE MD OCCURRED		NON-COINCIDENT	09/12/2020
			MAX MVA	08/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:30:00 PM
			MAX MVA	2:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Highfields	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.81
			MAX MVA	4.08
	DATE MD OCCURRED		NON-COINCIDENT	14/07/2020
			MAX MVA	10/08/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
Home Hill	RAW ADJUSTED MD	MVA	NON-COINCIDENT	13.05
			MAX MVA	13.09
	DATE MD OCCURRED		NON-COINCIDENT	21/12/2020
			MAX MVA	22/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Hughenden	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.33
			MAX MVA	16.45
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	02/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Ilbilbie	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.73
			MAX MVA	0.77
	DATE MD OCCURRED		NON-COINCIDENT	20/12/2020
			MAX MVA	01/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	8:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Ingham	RAW ADJUSTED MD	MVA	NON-COINCIDENT	10.68
			MAX MVA	11.21
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	29/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:30:00 PM
			MAX MVA	10:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Isis Central Mill	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.04
			MAX MVA	4.30
	DATE MD OCCURRED		NON-COINCIDENT	13/07/2020
			MAX MVA	13/08/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	10:00:00 AM
			MAX MVA	9:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER

Jarvisfield	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.98
			MAX MVA	5.99
	DATE MD OCCURRED		NON-COINCIDENT	15/12/2020
			MAX MVA	15/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Jubilee Pocket	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.59
			MAX MVA	10.27
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	23/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	8:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Kalamia	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.63
			MAX MVA	7.21
	DATE MD OCCURRED		NON-COINCIDENT	22/11/2020
			MAX MVA	04/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	1:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Kidston	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.28
			MAX MVA	0.28
	DATE MD OCCURRED		NON-COINCIDENT	05/01/2021
			MAX MVA	16/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:00:00 PM
			MAX MVA	10:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Killarney	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.05
			MAX MVA	2.10
	DATE MD OCCURRED		NON-COINCIDENT	28/07/2020
			MAX MVA	15/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 AM
			MAX MVA	7:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
Koumala	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.39
			MAX MVA	1.62
	DATE MD OCCURRED		NON-COINCIDENT	06/12/2020
			MAX MVA	22/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:00:00 PM
			MAX MVA	12:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Lakeland	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.53
			MAX MVA	2.42
	DATE MD OCCURRED		NON-COINCIDENT	01/12/2020
			MAX MVA	10/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	9:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Louisa Creek	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.37
			MAX MVA	2.40
	DATE MD OCCURRED		NON-COINCIDENT	07/02/2021
			MAX MVA	08/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Mackay City	RAW ADJUSTED MD	MVA	NON-COINCIDENT	14.61
			MAX MVA	14.73
	DATE MD OCCURRED		NON-COINCIDENT	23/02/2021
			MAX MVA	23/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:30:00 PM
			MAX MVA	3:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Macknade	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.40
			MAX MVA	3.97
	DATE MD OCCURRED		NON-COINCIDENT	23/07/2020
			MAX MVA	01/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
Mareeba	RAW ADJUSTED MD	MVA	NON-COINCIDENT	21.18
			MAX MVA	22.22
	DATE MD OCCURRED		NON-COINCIDENT	23/12/2020
			MAX MVA	24/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Marian South	RAW ADJUSTED MD	MVA	NON-COINCIDENT	6.23
			MAX MVA	6.39
	DATE MD OCCURRED		NON-COINCIDENT	20/12/2020
			MAX MVA	18/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Miles-Condamine	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.74
			MAX MVA	1.57
	DATE MD OCCURRED		NON-COINCIDENT	30/11/2020
			MAX MVA	03/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 PM
			MAX MVA	6:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Miriam Vale	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.77
			MAX MVA	7.19
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	05/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	6:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Mitchell	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.22
			MAX MVA	2.24
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	03/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	2:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Monduran Dam	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.11
			MAX MVA	0.19
	DATE MD OCCURRED		NON-COINCIDENT	29/06/2020
			MAX MVA	22/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:30:00 PM
			MAX MVA	4:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
Moorvale	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.82
			MAX MVA	5.87
	DATE MD OCCURRED		NON-COINCIDENT	07/02/2021
			MAX MVA	07/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Moranbah Town	RAW ADJUSTED MD	MVA	NON-COINCIDENT	20.87
			MAX MVA	22.09
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	08/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Moura	RAW ADJUSTED MD	MVA	NON-COINCIDENT	8.10
			MAX MVA	8.93
	DATE MD OCCURRED		NON-COINCIDENT	07/02/2021
			MAX MVA	30/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Mt Morgan	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.23
			MAX MVA	3.46
	DATE MD OCCURRED		NON-COINCIDENT	21/02/2021
			MAX MVA	22/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:30:00 PM
			MAX MVA	6:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Mt Sibley	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.41
			MAX MVA	8.82
	DATE MD OCCURRED		NON-COINCIDENT	01/12/2020
			MAX MVA	23/08/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Mundubbera Town	RAW ADJUSTED MD	MVA	NON-COINCIDENT	6.54
			MAX MVA	6.65
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	23/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Nanango	RAW ADJUSTED MD	MVA	NON-COINCIDENT	7.69
			MAX MVA	7.70
	DATE MD OCCURRED		NON-COINCIDENT	06/12/2020
			MAX MVA	02/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	5:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Normanton	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.94
			MAX MVA	5.76
	DATE MD OCCURRED		NON-COINCIDENT	03/12/2020
			MAX MVA	16/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:30:00 PM
			MAX MVA	1:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

North Cloncurry	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.96
			MAX MVA	6.42
	DATE MD OCCURRED		NON-COINCIDENT	01/12/2020
			MAX MVA	02/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
North Street	RAW ADJUSTED MD	MVA	NON-COINCIDENT	18.22
			MAX MVA	21.88
	DATE MD OCCURRED		NON-COINCIDENT	10/08/2020
			MAX MVA	06/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	4:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
Norwin	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.10
			MAX MVA	2.13
	DATE MD OCCURRED		NON-COINCIDENT	30/11/2020
			MAX MVA	26/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Oonoonba	RAW ADJUSTED MD	MVA	NON-COINCIDENT	14.11
			MAX MVA	15.05
	DATE MD OCCURRED		NON-COINCIDENT	25/03/2021
			MAX MVA	08/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Pampas	RAW ADJUSTED MD	MVA	NON-COINCIDENT	7.43
			MAX MVA	11.43
	DATE MD OCCURRED		NON-COINCIDENT	25/03/2021
			MAX MVA	20/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	7:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Peranga	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.72
			MAX MVA	1.73
	DATE MD OCCURRED		NON-COINCIDENT	06/12/2020
			MAX MVA	01/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	5:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Pirrinuan	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.64
			MAX MVA	1.90
	DATE MD OCCURRED		NON-COINCIDENT	06/12/2020
			MAX MVA	01/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	7:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Pozieres	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.81
			MAX MVA	3.06
	DATE MD OCCURRED		NON-COINCIDENT	27/03/2021
			MAX MVA	23/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	6:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Purrawunda	RAW ADJUSTED MD	MVA	NON-COINCIDENT	6.05
			MAX MVA	6.71
	DATE MD OCCURRED		NON-COINCIDENT	26/02/2021
			MAX MVA	01/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Rasmussen	RAW ADJUSTED MD	MVA	NON-COINCIDENT	17.94
			MAX MVA	17.97
	DATE MD OCCURRED		NON-COINCIDENT	07/02/2021
			MAX MVA	24/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	6:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Ravenshoe	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.57
			MAX MVA	3.37
	DATE MD OCCURRED		NON-COINCIDENT	17/07/2020
			MAX MVA	06/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 AM
			MAX MVA	11:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
Ravenswood	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.18
			MAX MVA	3.57
	DATE MD OCCURRED		NON-COINCIDENT	05/03/2021
			MAX MVA	07/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:00:00 PM
			MAX MVA	7:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Richmond	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.64
			MAX MVA	3.86
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	16/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Rockhampton Glenmore	RAW ADJUSTED MD	MVA	NON-COINCIDENT	22.87
			MAX MVA	27.82
	DATE MD OCCURRED		NON-COINCIDENT	23/02/2021
			MAX MVA	13/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	2:30:00 PM
			MAX MVA	2:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Rockhampton South	RAW ADJUSTED MD	MVA	NON-COINCIDENT	13.16
			MAX MVA	13.32
	DATE MD OCCURRED		NON-COINCIDENT	23/02/2021
			MAX MVA	17/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	2:30:00 PM
			MAX MVA	3:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Roma West	RAW ADJUSTED MD	MVA	NON-COINCIDENT	4.95
			MAX MVA	5.75
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	30/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	4:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Rosella	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.58
			MAX MVA	6.37
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	09/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	8:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
Saunders	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.38
			MAX MVA	1.42
	DATE MD OCCURRED		NON-COINCIDENT	08/02/2021
			MAX MVA	26/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:00:00 PM
			MAX MVA	6:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

Skid D (Landing Road)	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.53
			MAX MVA	1.60
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	24/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:30:00 PM
			MAX MVA	2:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
South Mackay	RAW ADJUSTED MD	MVA	NON-COINCIDENT	17.30
			MAX MVA	17.52
	DATE MD OCCURRED		NON-COINCIDENT	25/03/2021
			MAX MVA	03/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	1:00:00 PM
			MAX MVA	1:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Stamford	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.27
			MAX MVA	0.58
	DATE MD OCCURRED		NON-COINCIDENT	25/11/2020
			MAX MVA	09/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:30:00 PM
			MAX MVA	4:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Tara	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.70
			MAX MVA	3.40
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	03/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	2:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Toowoomba Central	RAW ADJUSTED MD	MVA	NON-COINCIDENT	23.36
			MAX MVA	23.40
	DATE MD OCCURRED		NON-COINCIDENT	16/11/2020
			MAX MVA	02/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:00:00 PM
			MAX MVA	3:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Torquay	RAW ADJUSTED MD	MVA	NON-COINCIDENT	29.45
			MAX MVA	30.11
	DATE MD OCCURRED		NON-COINCIDENT	22/02/2021
			MAX MVA	24/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	6:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER

Townsville Port	RAW ADJUSTED MD	MVA	NON-COINCIDENT	10.14
			MAX MVA	12.26
	DATE MD OCCURRED		NON-COINCIDENT	23/03/2021
			MAX MVA	21/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Vermont	RAW ADJUSTED MD	MVA	NON-COINCIDENT	11.21
			MAX MVA	11.60
	DATE MD OCCURRED		NON-COINCIDENT	04/06/2020
			MAX MVA	04/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	9:00:00 AM
			MAX MVA	4:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
Wandoan	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.50
			MAX MVA	15.24
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	19/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	7:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
West Toowoomba	RAW ADJUSTED MD	MVA	NON-COINCIDENT	24.36
			MAX MVA	24.85
	DATE MD OCCURRED		NON-COINCIDENT	10/08/2020
			MAX MVA	14/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	9:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
Winton	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.00
			MAX MVA	3.00
	DATE MD OCCURRED		NON-COINCIDENT	03/12/2020
			MAX MVA	03/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	6:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Wowan	RAW ADJUSTED MD	MVA	NON-COINCIDENT	5.99
			MAX MVA	72.20
	DATE MD OCCURRED		NON-COINCIDENT	22/12/2020
			MAX MVA	17/12/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:00:00 PM
			MAX MVA	1:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
Yarranlea South	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.44
			MAX MVA	1.85
	DATE MD OCCURRED		NON-COINCIDENT	05/12/2020
			MAX MVA	06/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	5:30:00 PM
			MAX MVA	9:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

(2) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	16.25
			MAX MVA	16.27
	DATE MD OCCURRED		NON-COINCIDENT	06/08/2020
			MAX MVA	26/08/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	12:00:00 PM
			MAX MVA	11:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
(1833) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.67
			MAX MVA	8.15
	DATE MD OCCURRED		NON-COINCIDENT	15/01/2021
			MAX MVA	05/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	4:00:00 PM
			MAX MVA	5:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(50) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.61
			MAX MVA	9.51
	DATE MD OCCURRED		NON-COINCIDENT	27/12/2020
			MAX MVA	29/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	2:30:00 AM
			MAX MVA	1:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
(426) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.87
			MAX MVA	2.06
	DATE MD OCCURRED		NON-COINCIDENT	15/06/2020
			MAX MVA	08/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	9:30:00 AM
			MAX MVA	9:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
(1758) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	6.39
			MAX MVA	6.43
	DATE MD OCCURRED		NON-COINCIDENT	11/11/2020
			MAX MVA	02/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:30:00 PM
			MAX MVA	12:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(102) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.00
			MAX MVA	1.14
	DATE MD OCCURRED		NON-COINCIDENT	08/12/2020
			MAX MVA	04/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 AM
			MAX MVA	11:00:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

(1864) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	28.96
			MAX MVA	28.99
	DATE MD OCCURRED		NON-COINCIDENT	02/11/2020
			MAX MVA	05/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	3:00:00 PM
			MAX MVA	3:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(151) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	16.55
			MAX MVA	16.62
	DATE MD OCCURRED		NON-COINCIDENT	19/03/2021
			MAX MVA	21/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	11:00:00 PM
			MAX MVA	8:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(161) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	28.17
			MAX MVA	28.73
	DATE MD OCCURRED		NON-COINCIDENT	19/08/2020
			MAX MVA	07/01/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	6:30:00 PM
			MAX MVA	10:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
(172) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.73
			MAX MVA	0.74
	DATE MD OCCURRED		NON-COINCIDENT	24/02/2021
			MAX MVA	23/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	12:30:00 PM
			MAX MVA	12:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(1898) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	7.92
			MAX MVA	11.28
	DATE MD OCCURRED		NON-COINCIDENT	30/06/2020
			MAX MVA	29/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:00:00 AM
			MAX MVA	12:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
(248) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.71
			MAX MVA	1.80
	DATE MD OCCURRED		NON-COINCIDENT	20/11/2020
			MAX MVA	18/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	9:30:00 AM
			MAX MVA	9:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

(257) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.51
			MAX MVA	3.52
	DATE MD OCCURRED		NON-COINCIDENT	05/06/2020
			MAX MVA	05/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	12:30:00 PM
			MAX MVA	1:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	WINTER
(1819) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	0.01
			MAX MVA	0.01
	DATE MD OCCURRED		NON-COINCIDENT	18/12/2020
			MAX MVA	23/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	2:00:00 PM
			MAX MVA	4:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(1894) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.08
			MAX MVA	6.42
	DATE MD OCCURRED		NON-COINCIDENT	28/07/2020
			MAX MVA	01/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	10:30:00 AM
			MAX MVA	7:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
(349) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	8.39
			MAX MVA	8.70
	DATE MD OCCURRED		NON-COINCIDENT	23/11/2020
			MAX MVA	29/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	8:00:00 PM
			MAX MVA	1:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(341) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	1.37
			MAX MVA	30.16
	DATE MD OCCURRED		NON-COINCIDENT	08/07/2020
			MAX MVA	03/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	11:00:00 AM
			MAX MVA	8:00:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
(1430) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	13.68
			MAX MVA	13.71
	DATE MD OCCURRED		NON-COINCIDENT	02/12/2020
			MAX MVA	09/06/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	1:00:00 PM
			MAX MVA	2:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER

(360) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	9.39
			MAX MVA	22.31
	DATE MD OCCURRED		NON-COINCIDENT	24/06/2020
			MAX MVA	18/02/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:00:00 PM
			MAX MVA	11:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER
			MAX MVA	SUMMER
(1910) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.06
			MAX MVA	18.70
	DATE MD OCCURRED		NON-COINCIDENT	09/12/2020
			MAX MVA	02/07/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 AM
			MAX MVA	8:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	WINTER
(1792) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.53
			MAX MVA	2.53
	DATE MD OCCURRED		NON-COINCIDENT	17/03/2021
			MAX MVA	18/03/2021
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	11:00:00 PM
			MAX MVA	12:30:00 AM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER
(476) Private Sub	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.14
			MAX MVA	2.14
	DATE MD OCCURRED		NON-COINCIDENT	18/02/2021
			MAX MVA	26/11/2020
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	7:30:00 PM
			MAX MVA	9:30:00 PM
	WINTER/SUMMER PEAKING		NON-COINCIDENT	SUMMER
			MAX MVA	SUMMER

BoP - 6.3 Sustained Interruptions

Table 6.3.1 - Sustained Interruptions to Supply

Compliance with the 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 three minutes.

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.

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).

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 (> 3 min) 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 (1 July) and the number of customers at the end of the reporting period (30 June)) 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].

Assumptions

Not applicable.

Estimated 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.

Explanatory Notes

Not applicable.