Ergon Energy
Basis of Preparation
Annual Reporting RIN

31 October 2019

ERGON. ENERGY NETWORK

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1.2 Compliance with AR RIN Requirements

Ergon Energy has prepared information provided in Template 2.11 table 2.11.3.1 Opex and table 2.11.3.2 Capex for Current Year in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix E and definitions in Appendix F to the RIN.

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

Ergon Energy notes that Reconciliation with Capex and Opex Worksheets – SCS is greyed out and automatically populated.

Ergon Energy has populated all variables to include all expenditure used to deliver standard control services that is associated with people.

Labour expenditure relates to:

- full time, part time and casual employees;
- ongoing and temporary employment contracts;
- labour hire contracts.

Labour expenditure includes wages, salaries, overtime payments, bonuses, allowances, incentive payments, superannuation, contributions, taxes (e.g payroll and fringe benefits taxes), termination and redundancy payments, workers compensation, training and study assistance, purchase made on behalf of employees (e.g protective clothing).

Non-labour expenditure are those other than Labour Expenditure.

1.3 Sources

Opex

Ergon Energy has sourced data from the Ellipse General Ledger and Project Accounting Module for the relevant regulatory year.

Capex

Refer to responses provided in relation to table 2.11.3.1 for source of information provided in response to Capex Labour.

1.4 Methodology

OPEX

In-house labour expenditure

In-house directly costed labour expenditure was calculated using general ledger codes. In addition, in-house labour expenditure included in network or corporate overheads was allocated to Opex and Capex proportionately based on the Direct Opex and Direct Capex Labour Costs. In 2018-19 a 70% rate was used to determine the SCS Overhead Portion being the average SCS rate applied on Labour overheads in the Category Analyis RIN (CA RIN).

Labour expenditure outsourced to related parties

In 2018-19 there was a material change to Energy Queensland Limited's (EQL) employment model where Ergon Energy's employees were transferred to EQL. As such EQL Labour is to be treated as in house / internal labour (not related party labour). This change in method was endorsed by the AER on 21 August 2019.

Labour expenditure outsourced to unrelated parties

These were identified by general ledger codes established to record contractor expenditure. As the cost structure of external contractors is commercially sensitive to the contractors concerned this information was not obtainable. Accordingly, all contractor expenditure has been reported as being labour.

Controllable non-labour expenditure

Controllable non-labour expenditure were confirmed to represent all non-labour expenditure that is not Uncontrollable non-labour expenditure. Such costs include materials and fuels, insurance and guaranteed service level (GSL) payments.

CAPEX

In-house labour expenditure

In-house labour expenditure was calculated using general ledger codes that identify in-house labour expenditure. In addition, in-house labour included in network or corporate overheads was allocated to Opex and Capex proportionately based on the Direct Opex and Direct Capex Labour Costs. In 2018-19 a 70% rate was used to determine the SCS Overhead Portion being the

average SCS rate applied on Labour overheads in the Category Analyis RIN (CA RIN).***Labour expenditure outsourced to related parties***

In 2018-19 there was a material change to Energy Queensland Limited's (EQL) employment model where Ergon Energy's employees were transferred to EQL. As such EQL Labour is to be treated as in house / internal labour (not related party labour). This change in method was endorsed by the AER on 21 August 2019.

Labour expenditure outsourced to unrelated parties

These were identified by general ledger codes established to record contractor expenditure. As the cost structure of external contractors is commercially sensitive to the contractors concerned this information has not been obtainable. Accordingly, all contractor expenditure has been reported as being labour.

Controllable non-labour expenditure

Controllable non-labour expenditure was confirmed to represent all non-labour expenditure that is not Uncontrollable non-labour expenditure. Such costs include materials and fuels, insurance and guaranteed service level (GSL) payments.

Uncontrollable non-labour expenditure

Uncontrollable non-labour expenditure was all non-labour expenditure over which Ergon Energy has no control. Uncontrollable non labour expenditure is imposed by an independent (that is, not a related party to Ergon Energy) government body (federal, state or local). Ergon Energy has no ability to influence any amount of the expenditure incurred by the manner in which Ergon Energy operates its business. Ergon Energy currently has no such expenditures.

1.5 Assumptions

No assumptions were made.

1.6 Estimated Information

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

1.7 Explanatory Notes

Not applicable.

2 BOP - 3.6 Quality of Service

2.1 Scope of BOP

2.1.1 Table 3.6.6.1 - Technical Quality of Supply

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2.1.6 Table 3.6.7.3 - Call Centre Performance

2.1.7 Table 3.6.7.4 - Number of Customer Complaints

2.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provide in Template 3.6 Quality of Supply, Table 3.6.6 – Complaints – Technical Quality of Supply and Table 3.6.7 Customer Service Metrics in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

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

Under the current issue Annual Reporting RIN, Ergon Energy is only required to populate “Number of complaints - technical quality of supply” in table 3.6.6.1, with the reminder of Table 3.6.6 Complaints, greyed out and not for completion.

In accordance with the AER’s clarification of 23 February 2016, reporting in Table 3.6.7.2 Total Number of Streetlights has been reported as the total number of streetlights for which Ergon Energy has responsibility to maintain.

Ergon Energy has not populated information in relation to Complaint – technical quality of supply (table 3.6.7.4) which is greyed out and not applicable to it for the regulatory control period.

2.3 Sources

Table 3.6.6 - Complaints - Technical Quality of Supply

Ergon Energy has sourced complaint numbers data from the Cherwell application for the financial year 2018-19. This application is used for capturing all customer feedback, positive and negative.

Table 3.6.7 - Customer Service Metrics

Ergon Energy has sourced data from:

- Cherwell as the application capturing customer feedback (positive and negative).
- Ergon Energy maintains several systems in regards to work request and work tracking through Ellipse (Work Requests and Work Orders) and the Field Force Automation device (FFA Tool)

(PLUMS database used to capture the entire number of unmetered connections (i.e. Streetlights) that are owned and maintained by Ergon Energy and third parties.

Table 3.6.7.3 - Call Centre Performance

Ergon Energy has sourced data from, Cisco Unified Intelligence Center (CUIC), which records all calls that are made to the Ergon fault lines.

Table 3.6.7.1 - Timely Provisions of Services

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

2.4 Methodology

Table 3.6.6 - Complaints - Technical Quality Of Supply

Ergon Energy has reported Customer Service complaints as sourced from the applicable system stated above, for the below categories of disaggregation:

- Complaint - reliability of supply
- Complaint - technical quality of supply
- Complaint - administrative process or customer service
- Complaint - connection or augmentation

- Complaint - other

For the purposes of reporting customer complaints at the dissemination required Ergon Energy has filtered on all negative complaints and has mapped the RIN categories from the existing feedback subcategories.

TABLE 3.6.7 - CUSTOMER SERVICE METRICS

Table 3.6.7.1 - Timely Provisions of Services

In relation to *Number of connections made* and *Number of connections not made on or before agreed date* - data provided is as per that sourced from Peace.

Peace is our market transaction and process tracking system that, in this case, stores the service request data. Numbers provided relate specifically to New Connection service requests. Those not made on agreed date are defined as having a completion date after the obligation date.

The use of DMK213: Completed NC & AA Service Orders vs Internal SLA Report.

The report provides information on all Service Orders completed between nominated dates and includes information to enable management analyse performance with respect to Service Orders completed as a comparison:

- Against the "Revised Obligation End Date (NC/SSWNC & AA)" if the NC/SSWNC/AA PTJ subclass has Comparison Type in SLA Matrix (DMK619) of "SCHEDDATE".
- Against the Market Obligation End Date if Comparison Type in SLA Matrix (DMK619) is "OBLIGDATE".

Exceptions;

If there is a Customer agreed Appointment Date or an Obligation End Date changed with Reason of 'F2 Dates', 'Network Activity Reqd', 'Customer Agreed', 'Customer Requested', 'Natural Disaster', 'Further Documentation', 'Internal Appointment', 'Excluded Location', 'Dependency Other Request', 'Local Holiday', 'Traffic Permit' and this extends the SLA, then this date will be applied to SLA calculations.

Table 3.6.7.2 - Timely Repair of Faulty Street Lights

In relation to repair of faulty street lights, all Work Orders, Work Requests and Field Force Automation (FFA) jobs created in 2017/18 were collated and cross referenced. Work Orders and FFA jobs were cleansed where:

- Start dates were before 01/07/17

- 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 existed

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 Street lights - average monthly number "out", the total count of cleansed corrective streetlight maintenance work orders is divided by 12.

In relation to Street lights - not repaired by "fix by" date, is a count of cleansed corrective streetlight maintenance work completed in greater than 5 days.

In relation to Street lights - average number of days to repair, the average days to complete of cleansed corrective streetlight maintenance work orders was calculated.

In relation to Total number of Streetlights – data is provided from the PLUMS database for the total count of Ergon Enegy Owned & Operated and Gifted and Ergon Energy Operated streetlights at the end of 2018-19.

Table 3.6.7.3 - Call Centre Performance

Calls to call centre fault line

- Calls to call centre fault line is the total number of calls to call centre fault line to be reported:

  (a) Including any answered by an automated response service and terminated without being answered by human operator; and
  (b) Excluding missed calls where the call centre fault line is overloaded.

Data is sourced from Cisco Unified Intelligence Center (CUIC) which records all calls that are made to the Ergon fault lines.

This allows Customer Operations to analyse call traffic for Ergon Energy inbound services such as 1300 and 13 numbers. It can be used to identify the number of telephone calls made to each telephone number. For the purposes of identifying the number of calls made to the Contact Centre’s fault line this tool provides the relevant totals. The tool is able to identify between fault line

calls and customer service calls, the latter is excluded for this requirement. The total includes all calls made, irrespective of whether the customer decided to speak with an operator or terminated the call whilst within the IVR system.

The Report used:

STPIS RIN Calls to Fault Line NORTHERN SOUTHERN

Parameters: financial Year 2018-19 dates.

The call total can then be entered into the parameters listed in Table 3.6.7.3 of the RIN.

***Calls to fault line answered within 30 seconds**:*

- Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls. From 1 July 2018 to 30 June 2019, Ergon Energy used a telephone platform supplied by Cisco to route telephone calls. This system provided a mechanism to distribute calls to Customer Operations Officers in the Customer Operations Department and also enable reporting of call activity. Reportable items for both systems include but are not limited to:

  a) Recording volume of calls received at the call centre:

  b) Recording the length of time between a caller entering the system and the call answered by an operator; and

  c) Recording the length of time between a caller entering the system and the caller abandoning the call.

- The Cisco platform data was extracted directly from the Cisco reporting system, Cisco Unified Intelligence Centre (CUIC) i.e. The STIPIS RIN Full Year NORTHERN SOUTHERN Report.

The Daily Reporting of Calls:

- A report is run in this system on a daily basis which provides the number of calls presented to agents, including the number of calls answered within 30 seconds, with the output saved and tracked in a spreadsheet.

Calls to fault line – average waiting time before call answered:

As per the description of Cisco telephony platform above, the reporting system is able to provide details of the length of time between a caller entering the system and the call being answered by an operator. The Cisco reporting system, CUIC, has been used to extract this information. Average waiting time before call answered is the average time in seconds from when calls enter the system

(including that time when a call may be ringing unanswered) and the caller speaks to a human operator or is connected to an interactive service that provides the information requested. The calculation for average wait time is total number of time waiting divided by total number of calls answered.

The Report used to record average Waiting Time in 2018-19 is the STIPIS RIN Full Year NORTHERN SOUTHERN.

Call centre – number of overload events:

Following the implementation of new contact centre technology in May 2015 the provision of additional capacity for calls to be received in to the CISCO telephony platform was included in the design. This replaced the previous Telstra system which diverted calls to a message when capacity in the preceding telephony platform was reached which was defined as being an overload event. There is therefore is no longer any calls classified as being part of an overload event since May 2015.

Calls Abandoned – percentage:

As per the description of the Cisco telephony platform above which explains the reporting systems ability to provide details of the number of calls where the caller abandons the call. The Cisco system the reporting system, CUIC, has been used to extract this information. Calls abandoned include all calls received and queued for a response by a human operator but are abandoned before being answered by the operator. This includes those calls abandoned prior to 30 seconds.

*The calculation for percentage of calls abandoned is total number of calls abandoned divided by total number of calls offered *100*

The Report used the STIPIS RIN Full Year NORTHER SOUTHERN

Table 3.6.7.4 - Number of customer complaints:

Ergon Energy has reported Customer Service complaints as sourced from the above stated systems, for the below categories of disaggregation:

- Complaint - reliability of supply
- Complaint - technical quality of supply
- Complaint - administrative process or customer service
- Complaint - connection or augmentation
- Complaint - other
- Total number of complaints

For the purposes of reporting customer complaints at the dissemination required Ergon Energy has filtered on all negative complaints and has mapped the RIN categories from the existing Cherwell subcategories.

Table 3.6.7.1 - Timely Provision of Services:

In relation to *Number of connections made* and *Number of connections not made on or before agreed date* - data provided is as per that sourced from Peace.

Peace is the market transaction and process tracking system that, in this case, stores the service request data. Numbers provided relate specifically to New Connection service requests. Those not made on agreed date are defined as having a completion date after the obligation date.

The data provides information on all Service Orders completed between nominated dates and includes information to enable management analyse performance with respect to Service Orders completed as a comparison:

- Against the "Revised Obligation End Date (NC/SSWNC/MSW & AA)" if the NC/SSWNC/MSW/AA PTJ subclass has Comparison Type in SLA Matrix (DMK619) of "SCHEDDATE".
- Against the Market Obligation End Date if Comparison Type in SLA Matrix (DMK619) is "OBLIGDATE".

Exceptions:

If there is a Customer agreed Appointment Date or an Obligation End Date changed with Reason of 'F2 Dates', 'Network Activity Reqd', 'Customer Agreed', 'Customer Requested', 'Natural Disaster', 'Further Documentation', 'Internal Appointment', 'Excluded Location', 'Dependency Other Request', 'Local Holiday', 'Traffic Permit' and this extends the SLA, then this date will be applied to SLA calculations

2.5 Assumptions

No assumptions were made.

2.6 Estimated Information

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 the Basis of Preparation.

2.7 Explanatory Notes

Not applicable.

3 BOP - 3.6.8 Network Feeders

3.1 Scope of BOP

3.1.1 Table 3.6.8 - NETWORK FEEDER RELIABILITY

3.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.8 Network Feeders, Table 3.6.8 – Network Feeder Reliability in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and in accordance with Economic Benchmarking RIN instructions and definitions (November 2013).

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

Ergon Energy has not populated information in relation to Momentary Feeder outages (MAIFI) which is greyed out and not applicable to it for the regulatory control period.

3.3 Sources

Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year.

Consumption for the “Energy Not Supplied” was sourced from the Network billing system Peace.

The line length data set for sourced from the Ergon Geospatial Information System (Smallworld) and represents the network as it was configured at the end of the relevant regulatory year.

3.4 Methodology

As relevant, Ergon Energy has also applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (November 2009) and Economic Benchmarking RIN instructions and definitions (November 2013), which remains applicable to Ergon Energy for the current regulatory control period.

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)
- Include all distribution feeders that experienced completed sustained (> 1min) unplanned and planned interruptions.

- Include all active distribution feeders that did not experience any interruptions and that have customers attached to the feeder as at 30 June in the relevant regulatory year
- A customer is defined as a premise having an assigned Active NMI with an Active Account. Customer numbers are held in the ECORP database.
- It should be noted that the totals of the above two line length data in this Table 3.6.8 have no bearing on the feeder classifications assigned to the distribution feeders for relevant financial year reliability performance reporting. The line length data that was utilised to assign feeder classifications is based on network as it was configured at the beginning of the relevant regulatory year.

Table 3.6.8 - Network Feeder Reliability

Feeder ID / Name is the unique ID as sourced from the FDRSTAT asset data.

Description of the service area for the feeder is as per the Geographical location of Ergon Energy's legacy supply regions – i.e. FN (Far North), NQ (Northern Queensland), MK (Mackay), CA (Capricornia), WB (Wide Bay), and SW (South West).

Feeder classifications 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.

Number of distribution customers on a feeder is calculated by adding the total of customers connected to the feeder at the beginning of the regulatory year (1 July) and the end of the regulatory year (30 June) and dividing the total by 2. If the feeder was only active for a short period throughout the year the customers where calculated by adding the total of customers connected to the feeder when the feeder became active in the regulatory year and when the feeder become inactive in the regulatory year and dividing the total by 2.

Length of HV distribution lines [overhead] contains the total length in km of Ergon Energy owned, as constructed, regulated overhead conductors for each feeder.

Length of HV distribution lines [underground] contains the total length in km of Ergon Energy owned, as constructed, regulated underground conductors for each feeder.

Maximum demand values on a distribution feeder during the regulatory year are provided in MVA. This is provided by Ergon Energy's System Development Group through the Current State Assessment report for distribution feeders. These are the MVA values that were utilised to assign the feeder classifications for the relevant regulatory year.

Energy Not Supplied MWh (unplanned and planned) has been calculated using data reported for unplanned/planned customer minutes off supply (Mins) multiplied by the average consumption by feeder (in minutes) sourced from Peace.

This is in accordance with methodology Chapter 7. Table 7.2 approach three *"average consumption of customers on the feeder based on their billing history"* as defined in the Economic Benchmarking RIN instructions and definitions (November 2013) for energy not supplied, inclusive of the exclusions under clause 3.3(b) (Major Event Days) and exclusive of the exclusions in accordance with clauses 3.3(a) of the AER's STPIS scheme and exclusive of Customer Installation Faults/Failures which reside beyond the electricity supply network.

The calculations are based on current connectivity by feeder and not connectivity at the time of the outage. For some feeders that no longer active or have changed connectivity in the system ECORP the average consumption per minute over all feeders is used. The methodology adopted is irrespective of the time of day the outages occurred.

Total number of unplanned outages records the total number of completed sustained unplanned interruptions that occurred on that distribution feeder during the relevant regulatory year, inclusive of exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

Unplanned customer minutes off-supply (SAIDI) (including excluded events and MEDs) represents SAIDI calculated by the summated feeder unplanned customer minutes on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, inclusive of all exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

Unplanned customer minutes off-supply (SAIDI) (after removing excluded events and MED) represents SAIDI calculated by the summated feeder unplanned customer minutes on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, after removing all exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

Unplanned interruptions (SAIFI) (including excluded events and MEDs) represents SAIFI calculated by the summated feeder unplanned customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, inclusive of all exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

Unplanned interruptions (SAIFI) (after removing excluded events and MEDs) represents SAIFI calculated by the summated feeder unplanned customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, after removing all exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

Total number of planned outages records the total number of completed sustained planned interruptions that occurred on the distribution feeder during the relevant regulatory year.

Planned customer minutes off-supply (SAIDI) (including MEDs) represents SAIDI calculated by the summated feeder planned customer minutes on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, inclusive of STPIS exclusions in accordance with clauses 3.3(b) of the AER's STPIS scheme .

Planned customer minutes off-supply (SAIDI) (after removing MED) represents SAIDI calculated by the summated feeder planned customer minutes on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, after removing STPIS exclusions in accordance with clauses 3.3(b) of the AER's STPIS scheme.

Planned interruptions (SAIFI) (including MEDs) represents SAIFI calculated by the summated feeder planned customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, inclusive of STPIS exclusions in accordance with clauses 3.3(b) of the AER's STPIS scheme.

Planned interruptions (SAIFI) (after removing MED) represents SAIFI calculated by the summated planned feeder customer interruptions on the feeder for the year divided by the average number of customers on the feeder for the relevant regulatory year, after removing STPIS exclusions in accordance with clauses 3.3(b) of the AER's STPIS scheme.

3.5 Assumptions

No assumptions were made.

3.6 Estimated Information

Ergon Energy has provided actual information for all information in Table 3.6.8 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.

3.7 Explanatory Notes

Not applicable.

4 BOP - 3.6.9 Network Reliability

4.1 Scope of BOP

4.1.1 Table 3.6.9 - Network Feeder Reliability - Planned Outages

4.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.9 Network Feeder Reliability, Table 3.6.9.1 Planned Minutes of Supply (SAIDI) and Table 3.6.9.2 Planned Interruptions to Supply (SAIFI) in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

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

Ergon Energy has not populated information in relation to CBD which is greyed out and not applicable to it for the regulatory control period.

4.3 Sources

Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year.

4.4 Methodology

3.6.9 - NETWORK FEEDER RELIABILITY - PLANNED OUTAGES

3.6.9.1 - PLANNED MINUTES OFF SUPPLY (SAIDI)

SAIDI for each feeder classification are calculated based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed planned sustained (> 1min) interruptions
- Feeder Classifications: Urban (UR), Short Rural (SR) & Long Rural (LR)
- SAIDI calculation - Customer minutes divided by average number of customers

Inclusive of the STPIS exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme for Electricity DNSPs (November 2009)

3.6.9.2 - PLANNED INTERRUPTIONS OFF SUPPLY (SAIFI)

SAIFI for each feeder classification are calculated based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed planned sustained (> 1min) interruptions
- Feeder Classifications: Urban (UR), Short Rural (SR) & Long Rural (LR)
- SAIFI calculation - Customer interruptions divided by average number of customers

Inclusive of the STPIS exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme for Electricity DNSPs (November 2009)

4.5 Assumptions

No assumptions were made.

4.6 Estimated Information

Ergon Energy has provided actual information in Table 3.6.9.1 and Table 3.6.9.2 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.

4.7 Explanatory Notes

Not applicable.

5 BOP - 6.2 STPIS Reliability

5.1 Scope of BOP

5.1.1 Table 6.2.1 - Unplanned Minutes off Supply (SAIDI)

5.1.2 Table 6.2.2 - Unplanned Interruptions to Supply (SAIFI)

5.1.3 Table 6.2.4 - Distribution Customer Numbers

5.2 Compliance with AR RIN Requirements

Ergon Energy has prepared information provided in Template 6.2 table 6.2.1 unplanned minutes of supply (SAIDI), table 6.2.2 Unplanned Interruptions to Supply (SAIFI) and table 6.2.4 Distribution Customer Numbers for current year in accordance with the RIN requirement, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

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

Ergon Energy has not populated information in relation to CBD which is greyed out and not applicable to it for the regulatory control period.

Ergon Energy has not populated information in relation to CBD and all variables relating to "Average customer numbers", which are greyed out and not applicable to it under the RIN issued.

5.3 Sources

Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year.

5.4 Methodology

Distribution Feeders are classified as Urban (UR), Short Rural (SR) & Long Rural (LR) as per the definitions in Appendix A of the AER's Electricity Distribution Network Service Providers (DNSPs), Service Target Performance Incentive Scheme (STPIS) (November 2009). Reporting is based on the feeder's classification at the end of the relevant regulatory year as at 30 June.

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.

Exclusions are applied in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme for Electricity DNSPs (November 2009), and excluding Customer Installation Faults/Failures which reside beyond the electricity supply network.

Whole of Network statistics (in the absence of specification) were assumed to encompass the summation of Urban (UR), Short Rural (SR) & Long Rural (LR) (customer minutes, customer interruptions and customer numbers).

6.2.1 - Unplanned Minutes off Supply (SAIDI)

Total sustained minutes off supply

SAIDI for each feeder classification are calculated based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classifications: UR, SR & LR
- Feeder Classification: Whole of network(summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers

Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

*Total of excluded events*see 3.3 of STPIS*

SAIDI for each feeder classification based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1min) interruptions
- Feeder Classifications: UR, SR & LR
- Feeder Classification: Whole of network(summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers

Summation of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

Total sustained minutes off supply after removing excluded events

SAIDI for each feeder classification was calculated based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1min) interruptions
- Feeder Classifications: UR, SR & LR
- Feeder Classification: Whole of network(summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers

Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

Table 6.2.2 - Unplanned Interruptions to Supply (SAIFI)

Total sustained interruptions

SAIFI for each feeder classification are calculated based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1min) interruptions
- Feeder Classifications: UR, SR & LR
- Feeder Classification: Whole of network(summation of UR, SR & LR)
- SAIFI calculation – Customer interruptions divided by average number of customers

Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

*Total of excluded events*see 3.3 of STPIS*

SAIFI for each feeder classification based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1min) interruptions
- Feeder Classifications: UR, SR & LR
- Feeder Classification: Whole of network(summation of UR, SR & LR)

- SAIFI calculation - Customer interruptions divided by average number of customers

Summation of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

Total sustained interruptions off supply after removing excluded events

SAIFI for each feeder classification was calculated based on the following criteria:

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (>1min) interruptions
- Feeder Classifications: UR, SR & LR
- Feeder Classification: Whole of network(summation of UR, SR & LR)
- SAIFI calculation - Customer interruptions divided by average number of customers

Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and Customer Installation Faults/Failures which reside beyond the electricity supply network.

Table 6.2.4 - Distribution Customer Numbers

Customer numbers at the start of the reporting period is the number of Customers (by feeder), measured on the first day of the Relevant Regulatory Year.

Customer numbers at the end of the reporting period is the number of Customers (by feeder), measured on the last day of the Relevant Regulatory Year.

A Customer is a distribution customer with an active account and active National Metering Identifier (NMI) i.e. inactive accounts are excluded.

Note: the whole of network customer number represents the sum of the total numbers of the customers on all three feeder classifications (UR, SR and LR) for each of the start and end of the report period.

The (greyed out) number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting.

Furthermore, the (greyed out) calculated average number of distribution customers for whole of network is the average of the total numbers of customers on all three feeder classifications (UR, SR and LR) at the beginning of the reporting period (1 July) and the total number of customers at the end of the reporting period (30 June), rounded up to nearest whole number.

5.5 Assumptions

No assumptions were made.

5.6 Estimated Information

Ergon Energy has provided actual information in Table 6.2.1 for the relevant regulatory year. Where information is provided it is done so in accordance with the AER's definitions and in accordance with Clauses 3.3(a) & (b) of the AER's STPIS scheme for Electricity DNSP's (November 2009), and applying the assumptions and methodology that is described within this Basis of Preparation.

5.7 Explanatory Notes

Not applicable.

6 BOP - 6.6 Customer Service

6.1 Scope of BOP

6.1.1 Table 6.6.1 - Telephone Answering

6.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 6.6 STPIS Customer Service, Table 6.6.1 Telephone Answering in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

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

Ergon Energy has not populated information in relation to “Percentage of calls answered within 30 seconds” relative to the “Number of calls after removing excluded events” which is greyed out as an automated field.

6.3 Sources

Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls. Between 1 July 2018 and 30 June 2019 Ergon Energy used a telephony platform supplied by Cisco.

This system provides a mechanism to distribute calls to Customer Operations Officers in the Customer Operations Department and enables reporting of call activity. Reportable items for this system include, but is not limited to:

- Recording volume of calls received at the call centre;
- Recording the length of time between a caller entering the system and the call answered by an operator; and
- Recording the length of time between a caller entering the system and the caller abandoning the call.

The system plays an Interactive Voice Recording (IVR) message prior to queuing the call for response by an operator. As stipulated in Appendix A of the Service Target Performance Incentive Scheme (STPIS), the time measured for a call begins after the caller decides to remain on the line after the IVR message is played.

Ergon Energy has sourced data from its Cisco reporting system, Cisco Unified Intelligence Centre (CUIC).

6.4 Methodology

A report is run in CUIC daily which provides the number of calls presented to agents with the output saved and tracked in a spreadsheet.

It should be noted that total calls used for calculating the STPIS grade of service are based on calls queued to agents only and does not include calls terminated by customers as the result of listening to a message through an automated response service.

Where major event days (MED) have been declared these dates have been entered in the relevant monthly tab with formulas in place to exclude the calls for these dates from the STPIS calculations. Calls related to specific excluded outages, as outlined in Appendix F of the RIN, are not removed as it is not possible to identify the exact number of calls generated because of a particular outage in the CISCO telephony system.

All monthly totals are shown on the “YTD Summary” tab of the main spreadsheet with annual totals for all calls and calls with MED approved exclusions removed.

6.5 Assumptions

No assumptions were made.

6.6 Estimated Information

Ergon Energy has provided actual information in Table 6.6.1 for the 2018-19 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.

6.7 Explanatory Notes

Not applicable.

7 BOP - 6.7 STPIS Daily Performance

7.1 Scope of BOP

7.1.1 Table 6.7.1 - Daily Performance Data - Unplanned

7.2 Compliance with AR RIN Requirements

Ergon Energy has prepared information provided in Template 6.7 table 6.7.1 Daily Performance Data - Unplanned for Current Year in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix B (template), Appendix A and definitions in Appendix F to the RIN.

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

Ergon Energy has not populated information in relation to MAIFI which is greyed out and not applicable to it for the regulatory control period.

7.3 Sources

Ergon Energy has sourced data from its Cisco reporting system, Cisco Unified Intelligence Centre (CUIC).

Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls. Between 1 July 2018 and 30 June 2019 Ergon Energy used a telephony platform supplied by Cisco. This system provides a mechanism to distribute calls to Customer Operations Officers in the Customer Operations Department and enables reporting of call activity. Reportable items for this system include, but is not limited to:

- Recording volume of calls received at the call centre;
- Recording the length of time between a caller entering the system and the call answered by an operator; and
- Recording the length of time between a caller entering the system and the caller abandoning the call.

The system plays an Interactive Voice Recording (IVR) message prior to queuing the call for response by an operator. As stipulated in Appendix A of the Service Target Performance Incentive Scheme (STPIS), the time measured for a call begins after the caller decides to remain on the line after the IVR is played.

Data was extracted directly from the Cisco reporting system, Cisco Unified Intelligence Centre (CUIC).

7.4 Methodology

A report is run in CUIC daily to provide the number of calls presented to agents with the output saved and tracked in a spreadsheet.

It should be noted that total calls used for calculating the STPIS grade of service are based on calls queued to agents only and does not include calls terminated by customers as the result of listening to a message.

Where major event days (MED) have been declared these dates have been entered in the relevant monthly tab with formulas in place to exclude these calls from the STPIS calculations. Calls related to specific excluded outages, as outlined in Appendix F of the RIN, are not removed as it is not possible to identify the exact number of calls related to a particular outage in the CISCO telephony system.

All daily totals are shown in each of the monthly tabs of the main spreadsheet and enable entry of daily data to be entered against the parameters listed in Table 6.7.1, being:

- Number of calls received (after removing excluded events)
- Number of calls answered in 30 seconds (after removing excluded events

7.5 Assumptions

No assumptions were made.

7.6 Estimated Information

Ergon Energy has provided actual information in Table 6.7.1 for the 2018-19 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.

7.7 Explanatory Notes

Not applicable.

8 BOP - 6.9 STPIS GSL

8.1 Scope of BOP

8.1.1 Table 6.9.1 - Guaranteed Service Levels - Jurisdictional GSL Scheme

8.2 Compliance with AR RIN Requirements

Ergon Energy has prepared information provided in Template 6.9 STPIS GSL, Table 6.9.1 Guaranteed Service Levels – Jurisdictional GSL Scheme in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

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

Ergon Energy has not populated information in relation to Guaranteed Service Levels – AER GSL Scheme which is greyed out and not applicable to if for the regulatory control period.

Where GSL parameters that do not fit within the provided sub-tables provided, headings have been entered and the relevant parameter(s) identified.

8.3 Sources

Ergon Energy has sourced data from Cherwell for the financial year 2018-19.

DMK530 GSL Report: Claims Period Reporting

8.4 Methodology

Section 2.4.2(a) of the Queensland Electricity Distribution Network Code (EDNC) requires distributors to provide the Queensland Competition Authority (QCA) within two months of each quarter, a report detailing compliance with the GSL outlined in clause 2.3 of the EDNC.

Data presented to the AER in meeting requirements of Template 6.9.1 Guaranteed Service Levels – Jurisdictional GSL Scheme have been presented in accordance with EDNC requirements and definitions unless otherwise stipulated under the AERs RIN issued.

Both numbers for Volumes and Value of Jurisdictional GSL are directly related to the count and sum of payments as identified and recorded as approved in the respective GSL system.

Report Used: DMK530 GSL Report: Claims Period Reporting

The Report was run on the date paid of GSL.

The report was run for the Financial Year 2018-19

- ALL GSL PAID – Shows count of Claims and $ values for claims paid grouped by GSL Type
- CUST GSL PAID – Shows count of Claims and $ values for claims paid grouped by GSL Type for Customer Initiated Claims
- CUST REJ – Shows the total number of claims received (based on date reported) and rejected (based on date rejected) grouped by GSL Type for Customer Initiated Claims
- DETAILS – Shows claims details where any of the dates are within the selected date range

DATES USED IN THIS REPORT

- Date Reported – Date first recorded in Cherwell i.e. when we first heard about the Claim and the GSL PTJ start date.
- Date Occurred – Date the actual breach occurred.
- Date Accepted – Date Cherwell investigators accepted the claim as valid and payable.
- Date Paid – Date the extract from Cherwell to Ellipse was produced to settle the claim.
- Date Rejected – Date the Cherwell Investigator rejected the claim.
- Validation of Data

Reconciled GSL Payments with Ellipse and Cherwell.

8.5 Assumptions

No assumptions were made.

8.6 Estimated Information

Ergon Energy has provided actual information in Table 6.9.1 for the 2018-19 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.

8.7 Explanatory Notes

Not applicable.

9 BOP - 7.8 Avoided TUOS Payments

9.1 Scope of BOP

1.1.4 Table 7.8.1 - Avoided TUOS Payments

9.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 7.8 Avoided TUOS Payments, Table 7.8.1 Avoided TUOS payment in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

Ergon Energy has populated all variables for cells shaded yellow as required by the RIN, with amounts represented as $0's, nominal.

9.3 Sources

Ergon Energy has sourced a list of invoices from retailers from the Market Transaction Centre.

9.4 Methodology

The methodology used in calculating the avoided cost payments is described in the Information Guide for Standard Control Services Pricing. The payments are calculated by the Market Transaction Centre using the process which is described below.

Ergon Energy confirms that in accordance with RIN requirements Avoided TUOS payments are taken to be payments made by Ergon Energy in accordance with clause 5.5(h) of the National Electricity Rules (NER).

Avoided TUOS expense is based on the list of invoices from retailers for the 2018-19 regulatory year.

Embedded Generators

Embedded generator (EG) is taken to have the meaning given in the NER.

Furthermore, clause 5.5(h) of the NER requires Distribution Network Service Providers (DNSPs) to calculate "avoided charges for the locational component of prescribed TUOS services", and clause 5.5(i) requires DNSPs to calculate the amount to be passed through to an EG. This is done by:

- Determining the charges for the locational component of prescribed TUOS services that would have been payable by the DNSP for the relevant financial year “if the EG had not injected any energy at its connection point during that financial year”; and

- Determining “the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the DNSP, which amount will be the relevant amount for the purposes of paragraph (h) [clause 5.5(h)]”.

Avoided TUOS payments are made by Ergon Energy to EGs who have sought access to Ergon Energy’s distribution network under clause 5.5 of the NER and who are registered as a Generator Rules Participant.

Also refer to the supplementary attachment for Revenues, for a further breakdown of DUOS and TUOS.

Market network service providers

Market Network Service Provider is taken to have the meaning given in the NER.

A Network Service Provider who has classified any of its network services as a market network service in accordance with Chapter 2 and who is also registered by AEMO as a Market Network Service Provider under Chapter 2.

Other (avoided TUOS payment)

Other (avoided TUOS payment) are any avoided TUOS payment made by a person that is not an EG or Market Network Service Provider

Ergon Energy has nil other (avoided TUOS payment) to report.

9.5 Assumptions

No assumptions were made.

9.6 Estimated Information

Ergon Energy has provided actual information in Table 7.8.1 for the 2018-19 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.

9.7 Explanatory Notes

Not applicable.

10 BOP - 7.10 Jurisdictional Scheme

10.1 Scope of BOP

10.1.1 Table 7.10.1 - Jurisdictional Scheme Payments

10.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 7.10 Jurisdictional Schemes, Table 7.10.1 Jurisdictional Scheme Payments in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and Definitions in Appendix F to the RIN.

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

Jurisdictional Scheme Payments are payments Ergon Energy is obliged to pay under an approved Jurisdictional Scheme, which has the meaning given in clause 6.18.7A(d) of the National Electricity Rules (NER).

Total Scheme Payments are reported in $0's, nominal.

10.3 Sources

Ergon Energy has extracted data from the Ellipse system for the Solar Feed-in-tariff (FiT) Bonus Scheme and the Electricity Industry levy.

Ergon Energy has sourced data from PEACE for the credits provided to the isolated network in relation to the solar bonus scheme.

10.4 Methodology

Jurisdictional schemes relevant to Ergon Energy are programs implemented by state governments that place legislative obligations on DNSPs.

Ergon Energy's annual Pricing Proposal sets out how jurisdictional scheme amounts (i.e. the amount(s) we are obligated to pay under the scheme) for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from the over or under recovery of those amounts. Clause 6.18.2(b)(6B) of the NER also requires our Pricing Proposal to describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria.

Current Jurisdictional Schemes relevant to Ergon Energy are:

- schemes set out explicitly under clause 6.18.7A(e) of the NER. For Queensland, this currently includes the Solar Bonus Scheme, which obligates Ergon Energy to pay a FiT for energy

supplied into our distribution network from specific micro-embedded generators (PVs). Ergon Energy became subject to the Solar Bonus Scheme on 21 May 2015 (i.e. the date we submitted our 2015–16 Pricing Proposal to the AER). Since that time, the jurisdictional scheme has not been amended; and

- schemes determined by the AER to be jurisdictional schemes under clause 6.18.7A(l) of the NER. For Queensland, this currently includes the energy industry levy. Ergon Energy is obligated under our Distribution Authority to pay a proportion of the Queensland Government's funding commitments for the AEMC in relation to this levy. Ergon Energy became subject to this Jurisdictional Scheme when it was approved by the AER on 22 April 2016. There have been no changes since this approval date.

Description of Cost Recovery Method

Attachment 14 of the AER's final distribution determination sets out the requirements Ergon Energy must comply with under clause 6.18.7A of the NER. Specifically, Ergon Energy must:

- earn jurisdictional scheme revenue amounts in the year it incurs those amounts; and
- apply a true-up to account for any under or over recovery of actual revenue (which in practice occurs on a two year lag through adjustments to tariffs)

For the 2018-19 regulatory year, this method is outlined in section 3.3.3 of our approved 2018-19 Pricing Proposal.

Ergon did not receive jurisdictional revenue from network tariffs in 2018-19 (to offset the 2018-19 solar expense). Ergon did receive solar grant revenue to offset this loss of revenue from network tariffs.

The solar grant revenue was based on the solar expense for 2018-19 less the over recovery amount from 2016-17. The grant revenue was released from unearned revenue from the balance sheet on a monthly basis.

As part of our 2019-20 annual Pricing Proposal, we will apply a true-up to account for any difference between our actual 2018-19 jurisdictional scheme revenue and our actual 2018-19 jurisdictional scheme payments (for both the FIT and the energy industry levy). On 31 May 2017 Ergon Energy received a Ministerial direction not to pass to customers any feed-in tariff jurisdictional scheme amounts not recovered between 1 July 2017 and 30 June 2020.

Total Scheme Payments

As relevant to Template 7.10, Jurisdictional Scheme payments have been reported on an accruals basis in accordance with Australian Accounting Standards.

The Payment amounts reported are amounts Ergon Energy is required to pay under the Jurisdictional Scheme obligations to:

1. pay to a person;
2. pay into a fund established under an Act of a participating jurisdiction;
3. credit against charges payable by a person;
4. reimburse a person;

less any amounts recovered by Ergon Energy from any person in respect of those amounts other than under the NER.

All values have been extracted from Ellipse.

Full year values have been extracted for the Solar Bonus Scheme and the Inter-Company Solar Bonus. The full year statutory amounts for these elements have been prepared on an unbilled basis.

The Electricity Industry levy was extracted from Ellipse using Ellipse Activity and element code. The levy is one payment for the year and is therefore presented on a billed basis.

Isolated Network adjustment to the annual Solar Bonus Scheme amount

1. A report (DMK535) was run on PEACE data to identify the solar bonus credits processed between 7 June 2018 and 6 June 2019 for NMIs on the isolated network. The following filters were entered into this report:
2. feeder class ERGIS (this filter restricts the data to NMIs on the isolated network);
3. Network Tariff Codes of NVG* and GVG* (These tariff codes are used for embedded generation. The symbol * is used to pick up all variations of the NVG tariff code: eg NVG0, NVGC0, NVGX0, NVG1, NVGC1, NVGX1, NVG2, NVGC2, NVGX2);
4. sub charge source description of Network DUoS Volume Charge (this filter restricts the data to the volume charges relating to the previously listed tariff codes);

The unfiltered (DMK535) report shows the dollar credits and the associated energy exported and used for all NMIs.

1. 7 June 2018 to 6 June 2019 corresponds to the dates used to generate statement of accounts (i.e. billing statements) for the 2018-19 financial year.
2. The PEACE credits and energy exported shown in the report were then summed to give annual totals.
3. The full year Solar Bonus Scheme value was reduced by the annual total for the Isolated Network Adjustment.

10.5 Assumptions

No assumptions were made.

10.6 Estimated Information

Ergon Energy has provided actual information in Table 7.10.1 for the 2018-19 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.

10.7 Explanatory Notes

Not applicable.

11 BOP - 7.11 DMIS DMIA

11.1 Scope of BOP

11.1.1 Table 7.11.1 - DMIA - Projects Submitted for Approval

11.2 Compliance with AR RIN Requirements

The AER approved the current DMIA allowance of $1 million per annum for the 2015-2020 regulatory period.

The actual spend for DMIA projects in 2018-19 did not exceed the $1 million annual allowance.

Template 7.11 – Demand Management Incentive Scheme for 2018-19 has been completed outlining the DMIA projects submitted for approval as part of Schedule 1.

11.3 Sources

Ellipse General Ledger

11.4 Methodology

The information provided in Table 7.11. DMIA Projects submitted for approval is consistent with what is reported in Schedule 1 of the RIN. Operating and capital expenditure (direct cost) for each project is obtained from the Ellipse General Ledger. Each project can be identified by its unique project number.

11.5 Assumptions

No assumptions were made.

11.6 Estimated Information

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

11.7 Explanatory Notes

Not applicable.

12 BOP - 8.1 Income

12.1 Scope of BOP

12.1.1 Table 8.1.1 - Income Statement

12.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 8.1 Income, Table 8.1.1.1 Revenue, Table 8.1.1.2 Expenditure and Table 8.1.1.3 Profit in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

All disclosures have been reconciled to the Audited Statutory Accounts of Ergon Energy's Parent Entity, Energy Queensland Limited. Please refer to Note 26 and 28(B) of the Energy Queensland Limited (EQL) Audited Statutory Accounts.

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

Also of note, the item "Pass through revenue (F-factor)" is not applicable to Ergon Energy.

Ergon Energy has not populated information in relation to Negotiated Services which is greyed out and not applicable during the regulatory control period.

12.3 Sources

Ergon Energy has sourced data from its Ellipse financial reporting system for the relevant regulatory year.

12.4 Methodology

REVENUE

The basis for the Statutory Column in the AR RIN Income Statement was a reconciliation performed between the data in the RIN Regulatory Account Balances report and the Statutory closed group accounts - Note 28(B). A $5.85m difference was identified due to the Loss Sale / Disposal of Assets element. In the RIN Account Balances Trial Balance data, this is an expense, but in the statutory accounts it forms part of the 'Gain on disposal of property, plant and equipment category'. This category includes both gains and losses. The $5.85m was mapped to Gain Income, and it reconciles to the Statutory accounts.

Distribution Revenue

Distribution Revenue is Revenue earned from the provision of SCS; ACS and excludes capital contributions. Ergon Energy does not have negotiated services to consider in this calculation.

Revenue is measured at the fair value of the consideration received or receivable. As a network service provider, Ergon Energy receives Distribution Use of System (DUOS) income.

As per AASB 15 Revenue from Contracts with Customers, the Economic Entity is using accrual accounting for unbilled network charges.

All values have been extracted from Ellipse.

Within the audited statutory accounts column, the revenue recognised is inclusive of revenue from regulated and unregulated services. The statutory accounts have been prepared on an unbilled basis in 2018-19. The adjustments column consists of:

- Unregulated revenue (identified by the activity segment of the chart of accounts);
- DUOS cross boundary revenue;
- The value of SCS distribution revenue is calculated using total DUOS revenue less: and
- DUOS cross boundary revenue.

This calculation enables the SCS distribution revenue to be presented on an unbilled basis.

The ACS revenue is obtained from a combination of activity codes and products in the general ledger. ACS revenue includes Streetlight revenue and Metering services revenue. The ACS revenue is reported on an accrual basis.

Cross Boundary Revenue

Cross boundary revenue is the inter- Distribution Network Service Provider (DNSP) revenue which is revenue from another DNSP for using Ergon Energy distribution network.

DUOS & TUOS revenue received from Essential Energy for 33kV and 66kV lines, based on metered data for 2018-19.

The adjustments column consists of:

DUOS cross boundary revenue;

TUOS cross boundary revenue

Cross boundary revenue is from billing information. Cross boundary revenue does not include an adjustment for Jurisdictional revenue in 2018-19. Jurisdictional revenue was replaced by the government grant for the Solar Bonus Rebate.

Contributions

Capital contributions (contribution) is cash or in kind contributions to capital expenditure (capex) projects and gifted assets.

Contributions relate to revenue in accordance with Ergon Energy's Connections Policy for SCS, and Contributions received for the delivery of ACS (such as Large Customer Connections and Real Estate Developments).

Cash capital contributions are received from small customers for subdivisions and other small customer initiated capital works (CICW) and gifted assets relate to Urban subdivisions and Commercial and Industrial customers.

Contributions for ACS are identifiable by separate codes within Ergon Energy's general ledger.

The adjustment between the Audited Statutory Accounts and the Regulated Distribution business relates to contributions received from unregulated sources, including the isolated networks.

Interest income

Ergon Energy no longer holds Cash Fund accounts, but has retained Working Capital Facility accounts; this is due to the change of funding arrangements by the State Government.

Interest is earned on its Working Capital Facility and from loans to SPARQ.

In accordance with Ergon Energy's 2015-20 Final Distribution Determination, Attachment 13 (Classification of Services) as interest revenue is not a direct control service it has been reported in the Adjustments column.

Jurisdictional scheme amounts

Ergon Energy has two approved Jurisdictional Schemes being the Feed-in Tariff, and the Electricity Industry Levy ((refer to Section 10 BOP – 7.10 Jurisdictional Scheme.

The Jurisdictional scheme amounts relating to the Feed-in Tariff forecast recovery and the Australian Energy Market Commission (AEMC) levy has been extracted from Ellipse using codes for Jurisdictional Scheme Use of System Charge, and Intercompany Use of System Jurisdictional Scheme.

The full year statutory amounts for these elements have been prepared on an unbilled basis.

The adjustments column consists of:

Government grant revenue related to the Solar Bonus

The grant revenue is identified by an element in the Ellipse system. It was adjusted out of Other Revenue. The grant revenue in 2018-19 includes an amount that should have been recovered in 2017-18.

Amounts reported in Template 7.8 for Jurisdictional Schemes are expenditure for the current year and will not align to revenue recovery, which is based on a monthly journal that includes solar expense (on an unbilled basis) and a prior year over recovery related to solar.

Profit from sale of fixed assets

The disposal of an item of Property, Plant & Equipment (PP&E) may occur in a variety of ways (e.g. by sale or scrapping at the end of its useful life). Ergon Energy's Asset Management Policy and Strategies discusses when assets should be disposed i.e. after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset.

In accordance with Ergon Energy's 2015-20 Final Distribution Determination, Attachment 13 (Classification of Services) the sale of inventory, asset or scrap is a non-distribution service that is unregulated. Therefore, the profit on sale of fixed assets has been reported in the Adjustments column (as an unregulated service) as it does not meet the definition for Service Segments (SCS, ACS, and Negotiated Services).

The figure reported in the statutory accounts is the amount of proceeds that exceeds the carrying amount of the item.

TUOS revenue

All values for TUOS revenue have been extracted from Ellipse, using the codes for TUOS Revenue, and Inter-Company TUOS Revenue. The external service provider has supplied information on an unbilled basis. The statutory accounts for TUOS revenue have been prepared on an unbilled basis in 2018-19. The adjustments column consists of:

- Unregulated revenue (relating to the use of the 220kV Network);

TUOS cross boundary revenue.

- The TUOS cross boundary revenue adjustment is from billing information.

Pass through revenue (F-factor)

This category is not applicable to Ergon Energy (it is a Victorian specific factor). This is not a row in the 2018-19 income statement template, and Ergon Energy has no data to report.

Other Revenue

The values in other revenue are from a range of Inter-Company transactions, and a variety of receipts. The majority of other revenue is from unregulated activities.

The adjustments column consists of:

- Unregulated revenue; and
- Government grant revenue related to the solar bonus

None of the Other revenue is classed as a SCS. The remainder is ACS revenue. The ACS revenue is categorised across service classifications according to their classification in the Ellipse general ledger.

EXPENDITURE

TUOS expenditure

TUOS costs are Transmission charges to be paid to transmission network service providers.

TUOS expense was obtained from an examination of the charges levied upon Ergon Energy and those passed on to retailers. TUOS expense is presented on an accrual basis from information in the General Ledger.

The adjustments column consists of:

- Cross Boundary charges (Energex);
- Non-Regulated charges (use of 220kV network)

The AER's Final Distribution Determination also requires Ergon Energy to maintain a TUOS unders and overs account, and to submit a record of all transmission related payment to the AER as part of its Annual Pricing Proposal

Avoided TUOS expenditure

Avoided TUOS payments are the payments by Ergon Energy in accordance with clause 5.5 (h) of the National Electricity Rules (NER).

Avoided TUOS expense is based on the list of invoices from retailers for the 2018-19 regulatory year.

The adjustments column consists of:

- Prior years avoided TUOS payments;
- Prior years accrual reversals;

- Current year accrual;
- Demand management payment for Barcaldine (again in 2018-19)

These payments agree to those Avoided Transmission Use of System Payments provided in Template 7.8 Avoided TUOS Payments (refer to Section 9 BOP - 7.8 Avoided TUOS Payments).

Cross boundary expenditure

Ergon Energy notes that the definition for 'Cross Boundary Charges', is the cost of using another DNSP's distribution network therefore Ergon Energy has included costs of using Energex's distribution network and costs for use of Ergon Energy's unregulated 220kV network. This is because under its Final Distribution Determination, Ergon Energy is allowed to pass through charges it incurs for use of Ergon Energy's unregulated 220kV network as a Designated Pricing Proposal Charge or 'TUOS' charge.

Depreciation

The Statutory approach for calculating depreciation has been used on a straight line basis by reference to the useful life of each item of PP&E, other than freehold land and easements which are not depreciated. An assessment of useful lives is performed annually. All values have been extracted from Ellipse.

The audited statutory accounts column includes depreciation and amortisation for Ergon Energy. It consists of amortisation of intangible assets such as computer software, licenses and customer contracts and relationships, and depreciation for supply systems, power stations, buildings, and other plant and equipment, as well as impairment of non PP&E assets, i.e. Impairment of Doubtful Debts.

The audited statutory accounts column does not include fleet depreciation. The fleet depreciation is part of the fleet management fee (FMF) expense, and is the major component of the FMF. The fleet depreciation is identified by codes in the Asset Depreciation report that start with V for vehicle, and this is the basis for isolating the fleet depreciation expense from other assets.

The approach for reporting by Service Segment for depreciation expense is in accordance with the AER's email of 7 September 2016. It is a subset of the statutory depreciation, yet only for those assets relative to the distribution business.

The adjustments column relates to depreciation and amortisation of Ergon Energy's unregulated power station assets comprising isolated generation and distribution systems, and other unregulated assets.

Finance charges

The statutory column is mostly Discount of non current Liability expense, this is partially offset by a Capitalised Interest credit.

Following the transfer of ownership of Ergon and Energex from the state to Energy Queensland Limited (EQL) on the 30 June 2016, transfers of debt for both DNSPs were made in order to comply with the Government Owned Corporations Regulation 2016 (Regulation).

The share of the State Government debt pool held by the DNSPs prior to the formation of the group was a liability held by each DNSP. In accordance with the Regulation, all DNSP debt (Queensland Treasury Corporation Loans) was transferred back to the Government debt pool. It was then transferred to the parent entity (EQL) at the carrying amount, such that: A share of Queensland debt is held in the EQL parent entity. Importantly, no debt raising costs were incurred by the DNSPs during 2018-19. No debt was raised or refinanced at the DNSP level.

Finance charges do not include any interest expense for long term debt or finance charges in 2018-19.

Interest expense is not a direct control service in the AER FDD Attachment 13, yet debt raising costs are an approved AER forecast cost.

The adjustments column consists of:

- Interest expense
- Capitalised Interest
- Discount of non-current Liability
- Bank charges

Impairment losses

In accordance with Appendix A (Principles & Requirements) to the RIN any revaluations or adjustments for impairment made in the Audited Statutory Accounts must be recorded in the adjustments column in the Financial Information Templates.

Impairment losses in the Audited Statutory Accounts are a special non-recurring charge taken to write down an asset with an overstated book value.

There are no impairment losses in 2018-19.

Jurisdictional scheme amounts

Ergon Energy has two approved Jurisdictional Schemes being the Feed-in Tariff, and the Electricity Industry Levy (refer to Section 10 BOP - 7.10 Jurisdictional Scheme).

The Feed-in Tariff expenses have been extracted from Ellipse. Full year values have been extracted for the Solar Bonus Scheme and the Inter-Company Solar Bonus. The full year statutory amounts for these elements have been prepared on an unbilled basis.

The Electricity Industry levy was extracted from Ellipse using a specific Ellipse code. The levy is one payment for the year and is presented on a billed basis.

Amounts are fully recoverable via charges to customers under SCS services.

In the annual statutory accounts, the feed-in tariff is classified as Statutory expenditure. The Electricity Industry levy was classified as Other expenditure. Therefore, the statutory value for Jurisdictional expenditure is the value of the feed-in-tariff.

The adjustment column consists of:

- Electricity Industry levy; and
- Exclusion of Isolated Solar NMI

Loss from sale of fixed assets

In accordance with Ergon Energy's 2015-20 Final Distribution Determination, Attachment 13 (Classification of Services) the sale of inventory, asset or scrap is a non-distribution service that is unregulated. Therefore, the loss on sale of fixed assets has been reported in the Adjustments column (as an unregulated service) as it does not meet the definition for Service Segments (SCS, ACS, and Negotiated Services).

The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale or scrapping at the end of its useful life). Ergon Energy's Asset Management Policy and Strategies discusses when assets should be disposed i.e. after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset.

Maintenance expenditure

Maintenance expenditure are those expenditures which are directly and specifically attributable to Maintenance that are not capex.

The Ergon Energy general ledger records maintenance costs in a series of codes that differentiate between SCS, ACS and unregulated based on the services they provide in accordance with the AER's Final Distribution Determination and the NER.

The identification of maintenance costs is performed by mapping these codes into their appropriate RIN reporting category

Operating expenditure excluding maintenance expenditure

The Ergon Energy general ledger records operating costs in a series of codes that differentiate between SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER.

The identification of maintenance costs is performed by mapping these codes into their appropriate RIN reporting category.

Other

The adjustment relates to unclassified costs of operating isolated and unregulated assets and "Not Proceeding Network Initiated Capital Works".

PROFIT

Profit before tax is calculated (total revenue less, total expenses).

Income tax expenses (/benefit) is calculated as 30.12% of profit before tax, for each Service Segment based on the services they provide in accordance with the AER FDD and the NER.

Profit after tax is calculated (Profit before less Income tax expenses (/ benefit)).

12.5 Assumptions

No assumptions were made.

12.6 Estimated Information

Ergon Energy has provided actual information in Table 8.1.1.1, Table 8.1.1.2 and Table 8.1.1.3 for the 2018-19 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.

12.7 Explanatory Notes

Not applicable.

13 BOP - 8.2 CAPEX

13.1 Scope of BOP

13.1.1 Table 8.2.1 - Capex by Purpose - Standard Control Services

13.1.2 Table 8.2.2 - Capex by Purpose - Material Difference Explanation

13.1.3 Table 8.2.3 - Capex Other

13.1.4 Table 8.2.4 - Capex by Asset Class

13.1.5 Table 8.2.5 - Capital Contributions by Asset Class

13.1.6 Table 8.2.6 - Disposals by Asset Class

13.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 8.2 Capex in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN.

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

TABLE 8.2.1 - CAPEX BY PURPOSE - STANDARD CONTROL SERVICES

TABLE 8.2.2 - CAPEX BY PURPOSE - MATERIAL DIFFERENCE EXPLANATION

TABLE 8.2.3 - CAPEX OTHER

TABLE 8.2.4 - CAPEX BY ASSET CLASS

NB. Ergon Energy has reported expenditure in table 8.2.1 inclusive of all SCS and ACS capital contributions (excluding public lighting) per RIN requirements.

Table 8.2.2 requires Ergon Energy to provide an explanation of the main drivers for material differences between forecast and actual expenditure for SCS that are identified in Table 8.2.1.

Differences are calculated in Table 8.2.1 – Capex by Purpose for all SCS categories presented therein.

Determination of whether differences are material aligns to the defined term ‘Materiality’ in paragraph 5 of the accounting standard AASB 108 as per the definition in Appendix F to the RIN. Generally, any material differences are those which are greater than 10% (between AER

approved forecasts (adjusted for the impact of actual inflation outcomes) and Ergon Energy's reported actual amount).

Where the difference between forecast and actual expenditure shown in table 8.2.1 is a Material Difference the main factors driving the difference are entered in Table 8.2.2 Capex by Purpose – Material Difference Explanation.

Schedule 1 Para 1.5-1.8 also requires Ergon Energy to identify each difference (where the difference is equal to or greater than ±10 per cent) between the amount reported in the Financial Information Templates and the amount provided for in the 2015-20 Distribution Determination for the following:

- total actual capex and total forecast capex.
- Explain the reasons for each difference identified

TABLE 8.2.5 - CAPITAL CONTIBUTION BY ASSET CLASS

Categories in Tables 8.2.5: Capital Contributions by Asset Class will be automatically populated as they are linked to Table 8.2.4: Capex by Asset Class.

TABLE 8.2.6 - DISPOSAL BY ASSET CLASS

Categories in Table 8.2.6: Disposals by Asset Class will automatically populate as they are linked to Table 8.2.4: Capex by Asset Class.

13.3 Sources

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

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

Ergon Energy has therefore drawn Capex data from three principle sources:

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

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

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

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

Where the Project remains under construction and is yet to be capitalised, details are extracted from the Ellipse estimating module to ascertain the types of assets under construction.

Once the information is extracted, the mapping tables are applied to convert the type of assets into the RIN asset categories per below methodologies and assumptions.

13.4 Methodology

TABLE 8.2.1 - CAPEX BY PURPOSE - STANDARD CONTROL SERVICES

Ergon Energy has reported forecast and actual Financial Information for SCS Capex by purpose, in categories reflective of those used in AER's final 2015-20 Distribution Determination for Ergon Energy.

Ergon Energy has sourced categories from Attachment 6 (Capital Expenditure) of the 2015-20 Distribution Determination, Table 6.3 (assessment of required capex by capex driver 2015–20), and notes capitalised overheads are presented as a separate category. As such, all other categories will be presented as directly attributable costs (exclusive of overheads).

Ergon Energy has reported expenditure in table 8.2.1 inclusive of all SCS and ACS capital contributions (excluding pubic lighting) per RIN requirements. Capital contributions are reported in the "Customer connections capex" line of the table.

Ergon Energy has removed any sharing of assets from SCS reported expenditure. The definition requires Capex to be the amounts included in the Regulatory Asset Base for Ergon Energy. In Ergon Energy's Final Distribution Determination Attachment 2 (RAB), heading (Separation of ACS and unregulated assets) the AER removed the equivalent of the ACS usage value of assets from the RAB. This approach also meets requirements of Ergon Energy's AER approved CAM par 9.3, Treatment of Capital Expenditure and Shared Assets.

Capex – Actual

Ergon Energy makes the below comments in relation to the process undertaken to report actual Capex by Categories:

Metering

Of note, there has been a reclassification of metering services from standard control to alternative control for Type 5 & 6 metering as outlined in Ergon Energy's 2015-20 Final Distribution Determination at Attachment 13 (Classification of Services). As such, Type 5 & 6 metering will not be reported in Table 8.2.1, rather they will be reported in Table 8.2.3 as an ACS. Caution would need to be taken when comparing metering costs for SCS with prior years.

Non-network

Non-network capex is extracted from projects and also from direct purchases.

The process used in reporting Captialised overheads, and Capital Contributions is described below:

Capitalised overheads

Within the Ergon Energy Ledger shared costs that have been charged via the overhead allocation process in accordance with the CAM are identified by an element code of 8100 within the chart of accounts hierarchy. The numbers shown against the category, 'Capitalised Overheads' are a summary of these overhead costs .

Capital Contributions

Actual Capital Contributions are not recorded against specific asset categories in the Ellipse general ledger. Therefore, an apportionment process has been applied to report against asset categories. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module.

The process used in categorising actual capex costs by voltage level is described below:

Voltage levels

Ergon Energy has assigned capex to subtransmission, High Voltage (HV) , Low Voltage (LV), and other in accordance with CA RIN definitions in the absence of AR RIN definitions and to ensure alignment in reporting between RIN's.

Capex has been categorized into Substransmision, HV, LV and other using the following logic:

- Subtransmission: where the nominal voltage is above 33kV, or transforms any voltage to levels above 33kV;
- High Voltage: where the nominal voltage is at or below 33 kV and above 11 kV, or distribute electricity at voltage levels between the sub transmission and LV sections of the network;

- Low Voltage: A line that is not a substransmission line or a HV feeder or an overhead service wire or an underground service cable.

The dissection by voltage class is prepared by reference to the Asset Register asset class which gives the voltage of each distribution or subtransmission asset. These are appropriately summarized and used to populate the relevant table.

The capex numbers are also adjusted for the proportion of those assets that will be used to provide services other than standard control capex. The amount of the reduction is determined after consideration of the appropriate drivers.

The movement in provisions by asset class is drawn from the calculations performed for the Benchmarking RIN which identifies the capex component for each movement. The total of these movements are then pro-rated across the various asset classes.

Related Party Margin Expenditure

'Related Party Margin Expenditure' comprises only profit margins or management fees paid directly or indirectly to related party contractors (not including actual incurred expenses of the related party contractor) for the regulatory reporting period.

Ergon Energy does not have any profit margins or management fees paid directly or indirectly for related party contracts to report.

Capex - CPI adjusted Forecast

Ergon Energy has used the forecasts contained in its 2015-20 Distribution Determination, adjusted for the impact of actual inflation outcomes to be in the same dollar terms as the actual data reported

The adjusted amounts were calculated by allowing for a change between forecast and actual Consumer Price Index (CPI) for the current regulatory year in the Post Tax Revenue Model (PTRM).

The actual CPI entered into the PTRM is consistent with Ergon Energy's annual Pricing Proposal and is based on the relevant Australian Bureau of Statistics (ABS) December to December CPI weighted average of 8 capital cities result sourced from the ABS website.

In order to disaggregate the forecasts, a separate Excel spread sheet was produced to recast the AER approved forecast Capex and forecast capital contributions into the RIN formats and into current year dollar terms. These figures were then reconciled against the forecast Capex and forecast capital contribution figures derived at the macro level from the CPI adjusted PTRM noted above.

TABLE 8.2.3 - CAPEX OTHER

Table 8.2.3 requires Ergon Energy to report actual and forecast capex that provides ACS.

The capex categories for ACS are pre-populated in Table 8.2.3 (Other Capex).

Ergon Energy has reported expenditure in table 8.2.3 exclusive of all capital contributions per RIN requirements.

Capex - Actual

Ergon Energy makes the below comments in relation to the process undertaken to report actual Capex by the categories for ACS as pre-populated in Table 8.2.3 (Other Capex).

Of note, the categories use AER services which align with Appendix A (AER final decision on classification of services for Queensland) of Attachment 13 (Classification of Services) in the 2015-20 Distribution Determination.

Public Lighting

Data for street lighting is extracted from the Ellipse system in the same manner described above under the Capex heading within the Methodology and Assumption Section for table 8.2.1 – Capex by Purpose – Standard Control Services with further filters applied to activity codes to obtain ACS (street lighting).

Connection Services

Data for connection services is extracted from the Ellipse system in the same manner described above under the Capex heading within the Methodology and Assumption Section for table 8.2.1 – Capex by Purpose – Standard Control Services with further filters applied to activity codes to obtain Connection Services capex.

Metering Services

Data for metering services is extracted from the Ellipse system in the same manner described above under the Capex heading within the Methodology and Assumption Section for table 8.2.1 – Capex by Purpose – Standard Control Services with further filters applied to activity codes to obtain Metering Services capex.

Of note, there has been a reclassification of metering services from standard control to alternative control for Type 5 & 6 metering as outlined in Ergon Energy's 2015-20 Final Distribution Determination at Attachment 13 (Classification of Services). As such, Type 5 & 6 metering will not be reported in Table 8.2.1, rather they will be reported in Table 8.2.3 as an ACS. Caution would need to be taken when comparing metering costs for SCS with prior years.

Ancillary Network Services

Data for Ancillary Services is extracted from the Ellipse system in the same manner described above under the Capex heading within the Methodology and Assumption Section for table 8.2.1 – Capex by Purpose – Standard Control Services with further filters applied to activity codes to obtain Ancillary Services capex.

Negotiated Services

Ergon Energy does not have any services classified as Negotiated for the current regulatory control period. Accordingly, Ergon Energy has not populated this row despite it not being greyed out as 'not for completion'.

The process used in categorising actual capex costs by voltage level is described below:

Voltage levels

Ergon Energy has assigned capex to subtransmission, HV, LV, and other in accordance with CA RIN definitions in the absence of AR RIN definitions and to ensure alignment in reporting between RIN's.

Capex has been categorized into Substransmision, HV, LV and other using the following logic:

- Subtransmission: where the nominal voltage is above 33kV, or transforms any voltage to levels above 33kV;
- High Voltage: where the nominal voltage is at or below 33 kV and above 1 kV, or distribute electricity at voltage levels between the sub transmission and LV sections of the network;
- Low Voltage: A line that is not a substransmission line or a HV feeder or an overhead service wire or an underground service cable.

Capex - Forecast

Forecasts must are adjusted for the impact of actual inflation outcomes to be in the same dollar terms as the actual data reported in the Financial Information Templates at Appendix B.

Actual Inflation applied is consistent with Ergon Energy's annual Pricing Proposal obtained from the ABS for the Weighted Average of 8 capital cities Dec – Dec period sourced from the ABS website.

Forecast capex costs for Public Lighting and Metering Services have been obtained from the Metering Capex data model, and Public Lighting pricing model issued with the 2015-20 Distribution Determination adjusted for the impact of actual inflation.

As the form of control for Ancillary network services and Connection Services are fee based or quoted services the AER did not approve Capex forecasts. As such, no financial values for forecasts are reported for these categories.

Related Party Margin Expenditure

'Related Party Margin Expenditure' comprises only profit margins or management fees paid directly or indirectly to related party contractors (not including actual incurred expenses of the related party contractor) for the regulatory reporting period.

Ergon Energy does not have any profit margins or management fees paid directly or indirectly for related party contracts to report.

Table 8.2.4 - Capex by Asset Class

Table 8.2.4 (Capex by Asset Class) requires Ergon Energy to report forecast and actual Financial Information for SCS Capex using categories which align with those set out in Ergon Energy's Post Tax Revenue Model and Roll Forward Model issued with the 2015-20 Distribution Determination as per definitions provided in Appendix F to the RIN.

Further, the AER requires reporting for Movements in provisions allocated to as-incurred capex by asset class. In accordance with the AER's clarification on the 15 April 2016, the purpose for providing this information is to adjust capex reported in the RAB in the Economic Benchmarking RIN Template 3.3 (Assets) commencing from 2015/16.

Ergon Energy has reported expenditure in table 8.2.4 exclusive of all capital contributions per RIN requirements (only tables 8.2.1 and 8.2.5 include capital contributions).

Finally, to meet with the definition of capex in Appendix F to the RIN, Ergon Energy is required to remove any sharing of assets in the delivery of ACS. The definition requires Capex to be the amounts included in the Regulatory Asset Base for Ergon Energy. In Ergon Energy's Final Distribution Determination Attachment 2 (RAB), heading (Separation of ACS and unregulated assets) the AER removed the equivalent of the ACS usage value of assets from the RAB. This approach will also meet the requirements of Ergon Energy's approved CAM par 9.3 Treatment of Capital Expenditure and Shared Assets.

Ergon Energy makes the below comments in relation to the process undertaken to report actual Capex by Asset Class in Table 8.2.4.

Capex - Asset Class

Ergon Energy's asset classes in the Roll Forward Model and Post-tax Revenue Model are duplicated to separate assets purchased prior to and after 1 July 2010 due to the applicability of differing asset lives. Therefore, for comparability purposes Ergon Energy has selected the asset

classes from the RFM. Of note, some asset classes (Street Lighting, Metering Type 5-6) are dedicated to the delivery of ACS, as such no financial values will be reported against these classes.

Capex - Actual

Capex by asset class is extracted from the Project Accounting module in the Ellipse ERP and by matching to fixed asset register classes and after balancing to the General Ledger provides capex in the AER capex by Asset Class reporting categories. The adjustment in capex for assets used for non-SCS purposes is also deducted. This amount is determined by considering a number of relevant cost drivers.

Capex - Forecast

Forecasts must be adjusted for the impact of actual inflation outcomes to be in the same dollar terms as the actual data reported in the Financial Information Templates at Appendix B.

Ergon Energy has used the forecasts contained in its 2015-20 Distribution Determination, adjusted for the impact of actual inflation outcomes to be in the same dollar terms as the actual data reported.

The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the current regulatory year in the PTRM.

The actual CPI entered into the PTRM is consistent with Ergon Energy's annual Pricing Proposal and is based on the relevant ABS December to December CPI weighted average of 8 capital cities result sourced from the ABS website.

Movements in provisions allocated to as-incurred capex by asset class

The movement in provisions is calculated in the Economic Benchmarking RIN Template 3.2.3 Provisions including the amount that relates to capex. This total amount is pro-rated across the asset classes.

Table 8.2.5 - Capital Contribution by Asset Class

Ergon Energy has reported expenditure in table 8.2.5 (and 8.2.1) inclusive of all SCS and ACS capital contributions (excluding public lighting) per RIN requirements.

Ergon Energy confirms, as per Appendix A 3.1 Capital Contributions is treated in accordance with the method approved in the 2015-20 Distribution Determination.

Capital Contributions - Actual

Actual Capital Contributions are not recorded against specific asset categories in the Ellipse general ledger. Therefore, an apportionment process has been applied to report against asset categories. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module.

Capital Contributions - Forecast

Ergon Energy has sourced financial values for forecasts from Table 6.3 (our assessment of required capex by capex driver 2015–20) to Ergon Energy's 2015-20 Distribution Determination, adjusted for the impact of actual inflation.

Table 8.2.6 - Disposal by Asset Class

Ergon Energy has reported expenditure in table 8.2.6 exclusive of all capital contributions per RIN requirements (only tables 8.2.1 and 8.2.5 include capital contributions).

Disposals - Actual

The financial values for actual disposals are required to be reported on a gross proceeds from the sale of assets basis as per definitions provided in Appendix F to the RIN.

The Ergon Energy fixed assets register records and reports the value of asset disposals as well as any proceeds received. This reporting is by the asset categories used in the asset register, these are mapped to the AER reporting categories using the mapping table used for the preparation of other AER templates requiring a similar dissection.

Disposals - Forecast

Ergon Energy has sourced financial values for forecasts from the Post Tax Revenue Model issued with the 2015-20 Distribution Determination, adjusted for the impact of actual inflation.

Actual Inflation applied is consistent with Ergon Energy's annual Pricing Proposal obtained from the ABS for the Weighted Average of 8 capital cities Dec – Dec period.

13.5 Assumptions

No assumptions were made.

13.6 Estimated Information

Ergon Energy has provided actual information in Template 8.2 for the current regulatory year.

Where information is provided Ergon Energy does so in accordance with the AER's definitions and applying the assumptions and methodology that is described within this Basis of Preparation.

13.7 Explanatory Notes

Not applicable.

14 BOP - 8.4 OPEX

14.1 Scope of BOP

14.1.1 Table 8.4.1 - Operating & Maintenance Expenditure - by Purpose

14.1.2 Table 8.4.2 - Operating & Maintenance Expenditure - by Purpose - Margins Only

14.1.3 Table 8.4.3 - Operating & Maintenance Expenditure - Explanation of Material Difference

14.2 Compliance with AR RIN Requirements

Ergon Energy has prepared information provided in Template 8.4 Operating Expenditure (Opex) 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 shaded yellow as required by the RIN.

Ergon Energy has not populated information in relation to Negotiated Services which is greyed out and not applicable in this regulatory control period.

Ergon Energy has not populated information in relation to Negotiated Services which is greyed out as results are automatically populated with formulas within the table.

Table 8.4.3 requires Ergon Energy to provide an explanation of the main drivers for material differences between forecast and actual expenditure for SCS that are identified in Table 8.4.1.

Differences are calculated in Table 8.4.1 – Opex by Purpose for all SCS and ACS categories presented therein.

Determination of whether differences are material aligns to the defined term ‘Materiality’ in accounting standard AASB 108 paragraph 5. Generally, any material differences are those which are greater than 5% to 10% (between AER approved forecasts (adjusted for the impact of actual inflation outcomes) and Ergon Energy’s reported actual amount).

Where the difference between forecast and actual expenditure are calculated in Table 8.4.1 the main factors driving the difference are entered in Table 8.4.3 – Operating & Maintenance Expenditure – Explanation of Material Difference. Please also refer to Explanations for material variances (Capex, Opex) which reports against Schedule 1 Para 1.5-1.8 also requires Ergon Energy to identify each difference (where the difference is equal to or greater than ±10 per cent)

between the amount reported in the Financial Information Templates and the amount provided for in the 2015-20 Distribution Determination for the following:

Total actual opex and total forecast opex; and

Explain the reasons for each difference identified.

14.3 Sources

Ergon Energy has sourced data from three principle sources:

- Ergon Energy's general ledger in Ellipse;

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

14.4 Methodology

Table 8.4.1 - Operating & Maintenance Expenditure by Purpose

Ergon Energy is to list the opex categories identified in Ergon Energy's regulatory proposal at table 3.2.1.1 current opex categories and cost allocations as per instructions. As such, Ergon Energy has recognised the item "Not Proceeding Network Initiated Capital Works" to "Other" in table 8.1.1.2.

Ergon Energy must specify any expenditure category where the expense is more than 5 per cent of the total SCS opex.

Ergon Energy makes the below comments in relation to the process undertaken to report actual Opex by Categories:

Preventive Maintenance

Comprises schedule inspection and maintenance activity. This work is carried out at predetermined intervals, or in accordance with prescribed intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep Ergon Energy staff and the public safe.

The cost of preventative maintenance is identified by separate codes within the general ledger is extracted for reporting total expenditure.

The adjustment relates to the cost of preventative maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger.

The cost of preventative maintenance on assets that provide ACS is also identified by an activity code within the general ledger coding structure.

Corrective Maintenance

Involves planned repair work identified and assessed as defects from preventative maintenance or customer reports in order to prevent an unplanned outage or dangerous electrical event. This category of work is planned and carried out regularly. The largest element of Ergon Energy's corrective maintenance program relates to vegetation management.

The cost of corrective maintenance is identified by separate codes within the general ledger. Reporting involves extracting the total expenditure.

The adjustment relates to the cost of corrective maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of corrective maintenance on assets that provide ACS is also identified by an activity code within the general ledger coding structure.

Forced Maintenance

Involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the distribution network to at least its minimum acceptable and safe operating condition. Although it is unplanned, an annual provision is made for this category of expenditure.

The cost of forced maintenance is identified by separate codes within the general ledger. Reporting involves extracting the total expenditure.

The adjustment relates to the cost of forced maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger.

The cost of forced maintenance on assets that provide ACS is also identified by an activity code within the general ledger coding structure.

Other network maintenance

Ergon Energy's maintenance costs are identified by specific codes within the General Ledger hence there are no amounts to be included in 'other'.

Network Operating costs

Network operating costs are separately identified in the Ellipse general ledger. Adjustments relate to amounts directly attributed to the isolated networks.

Meter reading

Costs incurred in Ergon Energy's capacity as a Metering Data Provider for Types 5, 6, and 7 metering installations and customer service activity reported against the relevant Service Segment in accordance with Ergon Energy's Final Distribution Determination Attachment 13 (Classification of Services).

The cost of meter reading is identified by separate codes within the general ledger. Reporting requires extracting the total expenditure from designated codes.

The adjustment relates to the cost of meter reading for customers on Ergon Energy's isolated and unregulated networks. These costs are separately identified in the general ledger.

Customer service (including Call Centre)

Customer Service relates to the cost of providing customer service to customers.

Customer Service costs is separately identified in the general ledger.

The adjustment relates to the cost of providing customer service to customers on Ergon Energy's isolated and unregulated networks.

Other Operating Costs

The regulated component of these costs relates, in part, to the DM incentive arrangements, GSLs which are separately identified in the Ellipse general ledger.

The adjustment relates to unclassified costs of operating the isolated systems, and unregulated assets

Training

Training relates to the cost of providing Training to Employees.

Training costs are separately identified in the general ledger.

Feed-in-tariff

A jurisdictional scheme associated with the Queensland Government Solar Bonus Scheme. For 2018-19 jurisdictional schemes are disclosed separately in Table 8.1.1.2 Expenditure and Template 7.10 Jurisdictional Schemes.

The Feed-in Tariff is separately identified in the general ledger.

Corporate Restructuring

Corporate Restructuring costs relating to the organisational restructure of Ergon Energy including employee redundancy payments.

Corporate restructuring costs are separately identified in the general ledger.

Non-network alternatives

Non-Network Alternatives (NNA) are systems and processes implemented to reduce peak demand on the shared network. As such, all expenditure is related to SCS.

NNA costs are separately identified in the general ledger.

Not Proceeding Network Initiated Capital Works

Not proceeding Network initiated capital works are costs Ergon Energy has incurred in progressing Network initiated capital works which did not proceed to completion.

In 2018-19 Ergon Energy recognised work as non-proceeding by removing the incurred cost that had been capitalised and allocated to an Asset Class (par 4.3 Appendix A), from the Regulatory Asset Base resulting in a loss on disposal of asset. Subsequently, as the sale (disposal) of inventory, asset or scrap is recognised as an unregulated non-distribution service in accordance with Attachment 13 (Classification of Services) in Ergon Energy's 2015-20 Final Distribution Determination the loss on disposal is unregulated. For statutory purposes expenditure is recognised in Work in Progress when incurred and capitalised on commissioning of the asset. As such non-proceeding works not yet capitalised are removed from WIP and reported as 'other' expenditure for the audited statutory accounts.

CPI Adjusted Forecasts

Forecasts must be adjusted for the impact of actual inflation outcomes to be in the same dollar terms as the actual data reported in the Financial Information Templates at Appendix B.

Ergon Energy has used the forecasts contained in its as 2015-20 Distribution Determination, and adjusted these amounts for actual consumer price index (CPI).

The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2018-19 regulatory year in the Post Tax Revenue Model (PTRM).

The actual CPI entered into the PTRM is based on the relevant Australian Bureau of Statistics (ABS) December to December CPI weighted average of 8 capital cities result sourced from the ABS website.

TABLE 8.4.2 - OPERATING & MAINTENANCE EXPENDITURE BY PURPOSE - MARGINS ONLY

Related Party Margin Expenditure

'Related Party Margin Expenditure' comprises only profit margins or management fees paid directly or indirectly to related party contractors (not including actual incurred expenses of the related party contractor) for the regulatory reporting period

For 2018-19 Ergon Energy does have profit margins or management fees paid directly or indirectly for related party contracts. Disclosed in table 8.4.2.

Energex provided Margin information based on invoice numbers issued to Ergon that fall within Ergon's AP data. The transactions with related party margins were mapped into the AR OPEX RIN categories.

Ergon Energy confirms, as required by the AER in Appendix F, Definitions that it has assessed its response to this templates in accordance with the related party definition.

14.5 Assumptions

No assumptions were made.

14.6 Estimated Information

Ergon Energy has provided actual information, in accordance with the AER's definition.

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.

14.7 Explanatory Notes

Not applicable.