Energex

Category Analysis RIN
Basis of Preparation

2015/16

energex

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1. BoP 2.1.1 - Expenditure Summary & Reconciliation

The AER requires Energex to provide the following categories relating to RIN table 2.1.1 Standard Control Services capex:

- Replacement expenditure
- Connections
- Augmentation expenditure
- Non-network
- Capitalised network overheads
- Capitalised corporate overheads
- Metering
- Public lighting
- Balancing item
- TOTAL GROSS CAPEX (includes capcons)
- Capcons

The AER requires Energex to provide the following categories relating to RIN table 2.1.2 Standard Control Services opex:

- Vegetation management
- Maintenance
- Emergency response
- Non-network
- Network overheads
- Corporate overheads
- Metering
- Public lighting
- Balancing item
- TOTAL OPEX

The AER requires Energex to provide the following categories relating to RIN table 2.1.3 Alternative Control Services capex:

- Connections
- Capitalised network overheads
- Capitalised corporate overheads
- Metering
- Public lighting
- Fee and Quoted
- Balancing item
- TOTAL CAPEX

The AER requires Energex to provide the following categories relating to RIN table 2.1.4 Alternative Control Services opex:

- Connections
- Network overheads
- Corporate overheads
- Metering

- **Public lighting**
- **Fee and quoted**
- **Balancing item**
- **TOTAL OPEX**

The AER requires Energex to provide the following categories relating to RIN table 2.1.5 Dual function assets capex:

- **Replacement expenditure**
- **Connections**
- **Augmentation expenditure**
- **Non-network**
- **Capitalised network overheads**
- **Capitalised corporate overheads**
- **Balancing item**
- **TOTAL GROSS CAPEX (includes Capcons)**
- **Capcons**

The AER requires Energex to provide the following categories relating to RIN table 2.1.6 Dual function assets opex:

- **Vegetation management**
- **Maintenance**
- **Emergency response**
- **Non-network**
- **Network overheads**
- **Corporate overheads**
- **Balancing item**
- **TOTAL OPEX**

These variables are part of Regulatory Template 2.1 Expenditure Summary.

All data within Template 2.1 Expenditure Summary are actual information.

Please refer to the Basis of Preparation for each individual Regulatory Template inputting into the Expenditure Summary and Reconciliation to identify the components that are Actual and Estimated Information.

1.1 Consistency with CA RIN Requirements

Table 1.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must calculate the expenditure for each capex and opex category reported in regulatory templates 2.2 to 2.10 and 4.1 to 4.4 and reports these amounts in the corresponding rows in tables 2.1.1 to 2.1.6.	Energex does not have dual function assets therefore no values were reported in RIN tables 2.1.5 and 2.1.6. These tables were not referred to hereafter. The line items reported in Template 2.1

Requirements (instructions and definitions)	Consistency with requirements
	equal, or in some cases sum to, the totals reported in templates 2.2 to 2.10 and 4.1 to 4.4. In particular, templates 2.5, 2.10 and 4.1 to 4.4 don't disaggregate capex and opex; however these numbers need to be separately identified in template 2.1. Note that from 1 July 2015, there are two major changes: 1. In recognition of the use of non-network assets in the delivery of ACS, an allocation of non-network capex is made in accordance with Energex approved CAM. However, Non-network expenditure presented in table 2.1.1 Standard control service capex includes SCS services as well as ACS services. 2. Energex no longer has services termed as "fee based services" or "quoted services" as required in templates 4.3 Fee Based Services and 4.4 Quoted Services. Instead, there are ancillary network services which include both fee based and quoted services. Therefore, ancillary network services expenditure will be input in templates 4.3 and 4.4 based on service categories in the Energex Pricing Proposal.
The total expenditure for the capex and opex for each service classification in Regulatory Template 2.1 must be mutually exclusive and collectively exhaustive. Total expenditure for capex must be reported on an "as-incurred" basis.	The total expenditure for capex and opex for each service classification in Regulatory Template 2.1 is mutually exclusive and collectively exhaustive. Total expenditure for capex is reported on an "as-incurred" basis.
Energex must report an amount that reconciles total capex and opex with the sum of the capex and opex line items in the "balancing item" row in each table in Regulatory Template 2.1. For the avoidance of doubt this means that the sum of each of the capex and opex	The balancing items reported by Energex in Template 2.1 contain only items that have been reported more than once within regulatory templates 2.2 to 2.10 and 4.1 to 4.4.

Requirements (instructions and definitions)	Consistency with requirements
line items in each of the tables in Regulatory Template 2.1 minus the balancing item must equal the total capex or opex line item in these tables. To do this the balancing item must: (a) Include the amount of capex and opex reported where these expenditures have been reported more than once within the Regulatory Templates 2.2 to 2.10, and 4.1 to 4.4; and Account for any differences arising due to the reporting of capex on a basis other than the "as-incurred" basis.	All capex is reported on an as-incurred basis therefore there are no balancing items for this component.
Energex must provide an excel spread sheet that contains the calculation of balancing items reported in Regulatory Template 2.1. At a minimum, this spread sheet must: (a) for each instance where an expenditure item is reported more than once (i.e. double counted), identify: (i) where that instance is reflected in expenditure included in the Regulatory Templates (ii) the value of that expenditure in each Regulatory Template (b) Identify each instance where the Notice requires Energex to report capex not on an "as-incurred" basis in Regulatory Templates 2.2 to 2.10 and, for the relevant expenditure item, list its corresponding value when expressed on an "as incurred" basis.	Energex has provided the calculation of balancing items reported in Regulatory Template 2.1 in Appendix 1 – Balancing Items and as a separate excel spread sheet. Where the expenditure figure is reported more than once (i.e. double counted) the spreadsheet identifies: (a) where that instance is reflected in the relevant Regulatory Templates; and (b) the value of that expenditure in the relevant Regulatory Template. All capex is reported on an "as incurred" basis and as such there were no balancing items for this component.
Energex must provide a reconciliation between the total capital and operating expenditure provided in the Regulatory Template 2.1 to the capital and operating expenditure recorded in Energex's Regulatory Accounting Statements and Audited Statutory Accounts.	Appendix 2 – Reconciling Items contains a reconciliation of total capex and opex for SCS and ACS, from the regulatory templates to the Annual Performance RIN to the Audited Statutory Accounts.

1.2 Sources

- Summary numbers in Regulatory Template 2.1 were sourced from the relevant CA RIN Regulatory Templates. Details of specific sources can be found in their respective Basis of Preparations.
- Balancing items in Regulatory Template 2.1 were sourced from a review of individual templates to identify items reported more than once.

- Reconciling items were sourced from a review of each Annual Performance RIN and/or supporting work papers, combined with the detailed workings for each relevant Regulatory Template.

Appendix 3 – Mapping Table contains mapping of the CA RIN capex categories to the Annual Performance RIN categories.

The statutory to Annual Performance RIN reconciliation is provided in **Appendix 2 – Reconciling Items** and reconciles:

- Capex from the Annual Performance RIN to the CAPEX reported in the audited statutory accounts. The CAPEX in the audited statutory accounts represents movements in Property, Plant and Equipment and Intangible assets Work in Progress for additions and capitalised interest; and

- Opex from the Annual Performance RIN to total expenses from the audited statutory accounts.

1.3 Methodology

The methodology for calculating balancing and reconciling items is detailed in section **Error! Reference source not found. Error! Reference source not found.**.

1.3.1 Assumptions

- Summary numbers are direct costs only, which are calculated as total costs less general overheads.

- General overheads are calculated in accordance with the approved Cost Allocation Method applicable for 2016.

- Summary numbers from the individual templates are not considered hereafter in this Basis of Preparation and further details can be found in the relevant Basis of Preparation for the individual templates.

1.3.2 Approach

Balancing items

Balancing item calculations are detailed in **Appendix 1 – Balancing Items.**

Balancing items have been calculated for amounts that appear more than once in the summary numbers, as detailed below:

- Fleet oncosts – captured as part of the direct capex and opex amounts for SCS and ACS (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in:
  - Template 2.6 Non-network as Motor Vehicles opex and Other Fleet Tools & Equipment opex; and

  - Template 2.10 Overhead as Corporate Overhead – Fleet.

- Materials oncosts – captured as part of the direct capex and opex numbers for SCS and ACS (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and captured in Template 2.10 Overhead as Network Overhead – Logistics and stores (POW Material Management).

- Property opex – captured in:
  - Template 2.6 Non-network as Buildings & Property opex; and
  - Template 2.10 Overhead as Corporate Overhead – Property.

- IT & Communications opex– captured in:
  - Template 2.6 Non-network IT & Communications opex; and
  - Template 2.10 Overhead as Corporate Overhead – IT and Communications.

- Metering the various line items within Template 4.2 Metering are duplicated as follows:
  - Meter Investigation – also captured in Template 4.3 Fee-Based Services as a Meter Inspect;
  - Special meter reading – also captured in various line items in Template 2.5 Connections and in Template 4.3 Fee-Based Services as Off-cycle Meter Reads
  - Scheduled Meter Reading – also captured in Template 2.10 Overheads as Network Overheads – Customer Services;
  - Other metering – certain items also captured in Template 4.3 Fee-Based Services as Reconfigure Meter

- Public Lighting opex– captured in:
  - Template 4.1 Public Lighting as light maintenance; and
  - Template 4.3 Fee Based Services and 4.4 Quoted Services.

- Connections – the various line items within Template 2.5 Connections are duplicated as follows:
  - Template 2.5 Connections; and
  - Template 4.3 Fee Based Services and 4.4 Quoted Services

- There is no duplication of Public Lighting capex as the numbers reported in Template 2.2 Repex and Template 4.1 Public Lighting are for different expenditure items (refer to Basis of Preparation 4.1.3 Public Lighting – Cost Metrics for more information).

Reconciling items

Where the summary numbers do not equal the Annual Performance RIN numbers, differences are detailed in the reconciliation included in **Appendix 2 – Reconciling Items.** These reconciling items typically relate to:

- Expenditure not included in the relevant regulatory templates as there was no basis on which to allocate a portion of expenditure to categories, but is included in the Annual Performance RIN numbers.
- Items which are excluded from (or included in) the relevant CA RIN regulatory templates in accordance with the definitions, but are included in (or excluded from) the Annual Performance RIN numbers.

Energex's approach to obtaining the regulatory accounting numbers is detailed in Table 1.2:

Table 1.2: Approach to obtaining Annual Performance RIN numbers

Table 2.1.1 - Standard control services capex	
	Actual ($ nominal)
	2016
Replacement expenditure	As per the AER CA RIN requirements (page 53, CA RIN explanatory statement), repex includes Control Centre - SCADA which was reported in non-system assets in the Annual Performance RIN.
Replacement expenditure	Directly from the Annual Performance RIN
Connections	Annual Performance RIN and/or supporting workings.
Augmentation Expenditure	Directly from the Annual Performance RIN
Non-network	Annual Performance RIN and/or supporting workings. Control Centre - SCADA direct costs are included in repex as explained above.
capitalised network overheads	Annual Performance RIN and/or supporting workings
capitalised corporate overheads	Annual Performance RIN and/or supporting workings
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL GROSS CAPEX (includes capcons)	Annual Performance RIN and/or supporting workings
capcons	Annual Performance RIN and/or supporting workings

Table 2.1.2 - Standard control services opex by category	
	Actual ($ nominal)
	2016
Vegetation management	Directly from the Annual Performance RIN
Maintenance	Directly from the Annual Performance RIN; includes Inspection and Planned Maintenance. Breakdown into Inspection and Planned Maintenance is obtained from the data supporting the Annual Performance RIN.
Emergency response	Directly from the Annual Performance RIN; includes Corrective Repair and Emergency Response from the Annual Performance RIN. Breakdown into Inspection and Planned Maintenance is obtained from the data supporting the Annual Performance RIN.
Non-network	Sum of opex totals from table 2.6 Non-network as non-network opex summary numbers are not available from the Annual Performance RIN
network overheads	Annual Performance RIN and/or supporting workings
corporate overheads	Annual Performance RIN and/or supporting workings
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL OPEX	Annual Performance RIN

Table 2.1.3 - Alternative control services capex	
	Actual ($ nominal)
	2016
Connections	Annual Performance RIN and/or supporting workings
capitalised network overheads	Annual Performance RIN and/or supporting workings
capitalised corporate overheads	Annual Performance RIN and/or supporting workings
Metering	Annual Performance RIN and/or supporting workings
Public lighting	Annual Performance RIN and/or supporting workings
Fee and quoted	Annual Performance RIN and/or supporting workings
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL CAPEX	Annual Performance RIN

Table 2.1.4 - Alternative control services opex	
	Actual ($ nominal)
	2016
Connections	Directly from the Annual Performance RIN
network overheads	Annual Performance RIN and/or supporting workings
corporate overheads	Annual Performance RIN and/or supporting workings
Metering	Directly from the Annual Performance RIN
Public lighting	Directly from the Annual Performance RIN
Fee and quoted	Annual Performance RIN and/or supporting workings
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL OPEX	Annual Performance RIN

1.4 Estimated Information

No Estimated Information was reported.

1.4.3 Justification for Estimated Information

Not applicable.

1.4.4 Basis for Estimated Information

Not applicable.

1.5 Explanatory notes

Explanatory notes can be found in the individual Basis of Preparations for respective Regulatory Templates.

1.6 Accounting policies

On a regular basis a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Energex. Changes are advised to the Audit & Risk Committee and implemented where required and the associated Energex accounting policies are updated accordingly.

2. BoP 2.2.1 - Repex Expenditure

The AER requires Energex to provide actual expenditure values and replacement volumes for the 2015/16 regulatory year in RIN table 2.2.1, for the following asset groups:

- **Poles, disaggregated by highest operating voltage and material type;**
- **Pole top structures, disaggregated by highest operating voltage;**
- **Overhead conductors, disaggregated by highest operating voltage and number of phases;**
- **Underground cables, disaggregated by highest operating voltage;**
- **Service lines, disaggregated by, connection voltage, customer type and connection complexity;**
- **Transformers, disaggregated by mounting type, highest operating voltage, ampere rating and number of phases;**
- **Switchgear, disaggregated by highest operating voltage and switch function;**
- **Public lighting, disaggregated by asset type and lighting obligation;**
- **SCADA, network control and protections systems, disaggregated by function; and**
- **Other, DNSP defined.**

Actual Information is provided for all figures.

These variables are a part of Regulatory Template 2.2 – Repex.

This Basis of Preparation excludes Asset Failures which is covered in a Basis of Preparation 2.2.2.

2.1 Consistency with CA RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1 – Demonstration of Compliance

Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 2.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category.	Not applicable as asset sub-categories have not been provided
In instances where Energex is reporting expenditure associated with asset refurbishments/ life extensions capex it must insert additional rows at the bottom of the table for the relevant asset group to account for this. Energex must provide the required data, applying the corresponding asset category name followed by the word “REFURBISHED”.	Not applicable
In instances where Energex considers that both the prescribed asset	Demonstrated in section

group categories and the sub-categorisation provisions set out in (a) do not account for an asset on Energex's distribution system, Energex must insert additional rows below the relevant asset group to account for this. Energex must provide the required data, applying a high level descriptor of the asset as the category name. The line item titled "OTHER – PLEASE ADD A ROW IF NECESSARY AND NOMINATE THE CATEGORY" illustrates this requirement. Energex must ensure that the sum of the individual asset categories, including any additional sub-category, additional other asset category or asset refurbishment/ life extension asset category expenditure reconciles to the total expenditure of the asset group.	2.5 - Explanatory notes and the Basis of Preparation for Regulatory Template 5.2 – Asset Age Profile.
Energex must ensure that the replacement volumes by asset group are equal to the applicable replacement volume data provided in Table 2.2.2.	Demonstrated in Step 4 – Final consistency check against RIN table 2.2.2 below.
Energex must ensure that the sum of the asset group replacement expenditures is equal to the total replacement expenditure contained in Regulatory Template 2.1.	Demonstrated in Basis of Preparation for Regulatory Template 2.1 - Expenditure Summary & Reconciliation.

2.2 Sources

The key data sources used to produce figures for replacement expenditure and asset replacement volumes through Distribution Monitoring Analytics (DMA) solution using source General Ledger (GL) Transaction table and Planning Approval Reports.

Table 2.2 below sets out the sources from which Energex obtained the required information.

Table 2.2: Information sources

	Variable	Source
Expenditure dollar values	Poles	DMA Solution
	Pole top structures	DMA Solution
	Overhead conductors	DMA Solution
	Underground cables	DMA Solution
	Service lines	DMA Solution
	Transformers	DMA Solution
	Switchgear	DMA Solution

	Variable	Source
	Public lighting	DMA Solution
	SCADA, network control and protection systems	DMA Solution
Volume of asset replacements	Poles	DMA Solution
	Pole top structures	DMA Solution
	Overhead conductors	DMA Solution
	Underground cables	DMA Solution
	Service lines	DMA Solution
	Transformers	DMA Solution
	Switchgear	DMA Solution
	Public lighting	DMA Solution
	SCADA, network control and protection systems	DMA Solution, Planning approval reports

2.3 Methodology

2.3.1 Assumptions

- At present, Energex does not report replacement expenditure according to the asset categories listed in RIN table 2.2.1. In order to satisfy the data requirements in RIN table 2.2.1, Energex had to develop a methodology of allocating replacement expenditure to the Repex asset categories.
- For each project that was analysed as part of RIN table 2.2.1, Energex has calculated a value of the life-to-date materials expenditure against each of the Repex asset categories. The materials expenditure for Repex asset categories has been converted into weighted averages, based on the materials expenditure in each Repex asset category relative to the total materials expenditure for the project. The weighted average values calculated for each Repex asset category was used as a basis for allocating total non-Repex material expenditure (labour, contract and others) to respective Repex asset categories in the Repex template.
- Asset replacement volumes for Service Lines include apportionment of Services replaced under (C2025, C2040, C2065, C2540 and C2545). These quantities have been calculated using 25m length for each service line quantity.
- Service line expenditure and volume split into Residential and Commercial & Industrial. The split between Residential and Commercial & Industrial service lines was based on the overall customer base, where 8% of customers are Commercial &Industrial and the

balance Residential. Refer basis of preparation 5.2.2 Asset age profile – Service lines for more information.

- ACS Public lighting projects included in Regulatory Template 4.1 were excluded from RIN table 2.2.1.
- Overhead conductor and underground cable replacement volumes were provided as “km”.

2.3.2 Approach

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

2.3.2.1 Replacement Expenditure Process

Step 1 – Replacement project data extraction

- A report was run from DMA solution source table – GL transaction which listed all replacement projects that incurred expenditure in the 2015/16 regulatory year under the replacement financial activity codes detailed in
- Table 2.3 below:

Table 2.3 – Replacement financial activity codes

Activity Code	Description	Typical Project Scope	Project Life Cycle
C2025	C20 - ART Asset Replacement - 11KV Network	Transmission replacement projects –overhead lines and Underground Cables (=11kV).	12 months to max of 4-5 years
C2040	C20 - ART Asset Replacement – Sub-transmission	Transmission replacement projects – power transformers, switchgear (>=11kV), overhead lines and Underground Cables (>11kV).	12 months to max of 4-5 years
C2065	C20 SCADA- ART Asset Replacement - SCADA / Telecoms	SCADA and Communications projects – Field Devices, various communication assets and Load Control devices	12 months to max of 4-5 years
C2540	C25 - ARD Ageing Assets	Distribution replacement	maximum 12 months

		projects – cross arms, transformers, switches, overhead lines and underground cables (<=11kV).	
C2545	C25 - ARD Pole Reinstatement & Pole Nailing	Distribution replacement projects – poles, pole staking	maximum 12 months

- This report provided a list of all transactions incurred on replacement projects over the period.
- About DMA Solution:
  - The Distribution Monitoring Analytics (DMA) Program introduced new capabilities to support the Asset Management Division to use information about Energex's assets in a way that improves network reliability, reduces network operations risks and enables proactive cost effective maintenance.
  - Previously information about our assets is housed in different repositories. DMA brought the data together so it is now easier to manage and better supports effective decision making.
  - DMA was designed to provide a single source of truth for asset information. Information from multiple systems brought together in two enterprise data solutions:
    - 1.The Enterprise Data Warehouse (EDW) and
    - 2. OSI PI Historian, which currently houses SCADA information.
  - The DMA program supports the vision for Energex to comply with PAS55 and ISO5500 global standards.

Step 2 – Stock code with Repex Asset Category code extraction

- Life to date material transaction records were used to allocate expenditure to the Repex asset categories for all projects that had expenditure in 2015/16.
- Stock code from Work orders - Every transaction happens under a work order which contains stock code with Repex asset category and expenditure.
- Stock code from Estimates - Every project in Energex contains an Ellipse estimate which contains stock code with Repex asset category code and estimated material amount. The process to get stock code from these estimates is to filter 'in-progress' and 'Authorised' estimates with management phase "04 – construct" and/or "14-construction warehouse".

Step 3 (a) – Apportionment Methodology – C20 (non-SCADA) & C25

- To illustrate how the apportionment process occurs is explained with a following example.
- From GL Transaction table, following transaction extracted for a Repex top project C0125252 DBS Replace 110kV Transformer with 2015/16 financial year expenditure.

Table 2.4 – GL Transaction 2015/16– Repex Project Transaction Example

Transaction No:	Expense Element	Transaction Amount	Repex Asset Category
67241280000	Labour	$500,000	Unknown
71872900000	Material	$790,000	TR Grd>66kV<=132kV<=100MVA
71872900002	Material	$10,000	Unknown
27874220000	Contract	$100,000	Unknown
67241280000	Other	$31,981	Unknown
	Total	***$1,631,981***	

- As shown in Table 2.4 material expenditure with Repex asset category will pass through directly to respective AER asset class. In the example, $790,000 will be allocated to AER asset class ‘TR Grd>66kV<=132kV<=100MVA’ in Repex Table 2.2 expenditure template.
- To allocate remaining unknown expenditure ($1,631,981 – $790,000 = $841,981), life to date Repex asset category material transaction expenditure associated with the respective top project is extracted using step 2. The materials expenditure for Repex asset category will be converted into weighted averages, based on the materials expenditure in each Repex asset category relative to the total Repex materials expenditure for the project.

Table 2.5 – Life to Date Repex Material – Top Project C0125252

Stock Code	Repex Asset Category	Transaction Amount	% Apportionment = (Material Transaction amount) / (Total Material Transaction)
SC19456	SCADA Field Devices	$214,000	2.29%
SC1256	Switchgear>22kV<=33kV;CB	$1,500,000	16.04%
SC69856	Switchgear>66kV<=132kV;CB	$1,440,000	15.39%

SC98647	TR Grd<22kV>60kVA<=600kVA;Multi Ph	$200,000	2.14%
SC64785	TR Grd>66kV<=132kV<=100MVA	$6,000,000	64.14%
Total cost of materials	***Total***	***$9,354,000***	***100%***

- Remaining unknown expenditure ($1,631,981 – $790,000 = $841,981), will be allocated to the respective Repex asset category based on weightings shown in Table 2.5.

Table 2.6 – Allocation of Expenditure – Top Project C0125252

Asset Category	Apportionment	Repex Expenditure
SCADA Field Devices	= 2.29% x $ 841,981	$19,263
Switchgear>22kV<=33kV;CB	= 16.04% x $ 841,981	$135,019
Switchgear>66kV<=132kV;CB	= 15.39% x $841,981	$129,619
TR Grd<22kV>60kVA<=600kVA;Multi Ph	= 2.14% x $841,981	$18,003
TR Grd>66kV<=132kV<=100MVA	= 64.14% x $841,981	$540,078
Total	***100%***	***$841,981***

Step 3 (b) – Apportionment Methodology – SCADA

- Manual interpretation is required for some of the SCADA projects for the following reasons
    - Materials are sometimes provided by contractors and hence have no stock codes to use for apportionment.
    - The labour component of the SCADA/Communications projects far exceeds the material costs. The material transaction amounts for SCADA/Communications assets are also substantially less than non-communication materials (e.g. Poles). Applying the apportionment methodology based on material cost over-allocates expenditure to the non-communication assets and misrepresents the SCADA/communication costs.
- Refer manual apportionment methodology (Step 4) for SCADA manual apportionment process.

Step 3 (c) – Apportionment Methodology – Pole Staking

- From GL Transaction Top project number, identify the work orders containing following pole staking Network Asset Management Program (NAMPs) – DF07, LF05, MS01 and SF08.

- Summation of these respective work orders expenditure will be allocated in RIN REPEX template accordingly for pole staking.

Step 4 – Manual Apportionment Methodology

- Manual apportionment is required for REPEX top projects in the following scenarios:
    - Where the data is returned from DMA as unmatched due to following reasons
        - Projects with no Repex AER asset category
        - Projects Repex transaction not able to produce weightings due to summation of material transaction is either zero or negative value.
    - SCADA projects as stated in Step 3 (b)

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

- Manually apportioned information will be fed back into the DMA solution to ensure that the reporting is governed and repeatable.

Step 5 – Template Input

- Outcome of apportionment methodology will be consolidated by Repex asset category and will be allocated accordingly in the Repex template Table 2.2.1

2.3.2.2 Replacement Volume Process

Step 1 and Step 2 are as same as illustrated in 2.3.2.1Replacement Expenditure process

Step 3 (a) – Replacement Volume – C25

- The lifecycle of C25 projects are typically a maximum of one year

- In Energex for C25 projects, material transaction work orders will be closed once the transacted material has been electrically commissioned.

- Using this material transaction work order closed date; materials commissioned in the nominated financial year go directly to the respective AER asset categories as ‘replacement volumes’ in REPEX template Table 2.2.1.

Step 3 (b) – Replacement Volume – C20 (non –SCADA)

- The lifecycle of C20 projects vary from one to multiple years
- Using the 'date in service' from each sub – project or product (stage) level of each top project, respective AER asset class commissioned in the nominated financial year is obtained.
- The validated quantities are entered into REPEX template Table 2.2.1 accordingly.

Step 3 (c) – Replacement Volume – SCADA

- As per Step 3 (b) C20 (non-SCADA); and
- Materials are sometimes provided by contractors and hence have no Energex stock codes with AER asset classification. These materials are added manually to ensure accuracy and completeness of the data (e.g. equipment sourced for the Matrix project)

Step 3 (d) – Replacement Volume –Pole Staking

- The 'replacement volume' for the 'staking of a wooden pole' category is obtained from the DMA source system 'Physicals Actual' table
- The total 'replacement volume' is the summation of the 'actual physical' count from NAMPs DF07, LF05, MS01 and SF08 with a 'work order closed date' in the given financial year.
- The summated quantity is entered in the REPEX template Table 2.2.1.

Step 4 – Final consistency check against RIN table 2.2.2

- Energex ensured that the "replacement volumes by asset group" was equal to the applicable replacement volume data provided in RIN table 2.2.2.

2.4 Estimated Information

Not Applicable

2.4.1 Justification for Estimated Information

Not Applicable

2.4.2 Basis for Estimated Information

Not Applicable

2.5 Explanatory notes

General issues

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

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

Asset specific issues

- Communications Network Assets and Communications Site Infrastructure have equipment where there is a significant amount of equipment not sourced through the Energex Store systems, thus it is necessary to manually adjust a range of figures to account for this.

- The 2015/16 expenditure for asset category ‘TR Grd>66kV<=132kV<=100MVA’ was -$1,000,900 (negative value which is credit). Following 3 projects contribute to this expenditure:

Table 2.7 – TR Grd>66kV<=132kV<=100MVA – 2015/16 Expenditure

Top Project ID	Project Description	2015/16 Expendture
C0125252	DBS - Replace Trfs.	$105,550.37
C0357175	canc CMA Capitalise TR7 repair cost	-$1,124,776.37
C0414414	CMA - Replace Failed TR7	$18,325.95
	Total	***-$1,000,900.05***

  - On the 15th November 2012, power transformer TR7 110/33kV 100MVA at Coomera SSCMA substation suffered an internal failure. To return the network to normal, the strategic spare transformer was permanently installed at Coomera. Capital project C0357175 was created for replacement of TR7 (with strategic spare) and repair of failed TR7.

  - At later stage, C0414414 was created to capitalise the installation of strategic spare at SSCMA. The failed transformer was then repaired and return back to inventory as a strategic spare. Therefore capital project C0357175 was cancelled and expenditure had been journaled from capital project C0357175 to store inventory. This is the reason in 2015/16 expenditure C0357175 had -$1,124,776.37

Other asset categorisation

- Energex identified expenditure in 15/16 that could not be allocated to existing replacement categories. This expenditure is listed in the other (DNSP defined) at the bottom of the template as “Other non AER Asset Categories”. This expenditure covers combination of following categories:
    - Non AER assets:
        - >=11kV <=33kV CT (Current Transformer)
        - >=1kV <= 11kV Capacitor
        - >=1kV <=11kV Regulator
        - TR Pole>22kV>60kVA<=600kVA;Multi P
        - Instrument Transformer
        - 110/132kV Insulators
        - Meter
        - NER – Neutral Earthing Resistor
        - OHEW – Over Head Earth Wire
        - Substation Batteries
        - Security Fence
        - Fire Protection System
        - Swipe Card Access
        - Surge Arrestors
        - Protection Fuses
        - Software Development
    - General Other:
        - Allocation of on costs: This reflects adjustments to actual costs, posted as an accrual at a high level only. Detailed entries are posted to projects in the following financial year. These amounts represent adjustments to the standard labour rates or oncost rates posted to projects throughout the year based on expected spend, with the adjustment reflecting the actual costs incurred.
        - Balancing WIP account: Expenditure with ‘unknown’ top project and work order information is -$31,806.24. A data quality (DQ) rule exists for work orders not attached to a project ‘FIN02 002 Capital Work Orders with

Costs Must Have Project'' – currently no exceptions. This requires finance to action any capital work orders with a balance. The transactions are clearing transactions from previous financial years. Due to this the transactions appearing in a reporting financial year that relate to previous financial years to clear Work in Progress account (WIP).

- The annual expenditure allocated to "Other Non AER Asset Categories" in the Repex model for the 2015/16 regulatory year was $9,395,069.

Differences between last CARIN (2014/15 data from Submission) VS 2015/16 CARIN methodology

Table 2.8 – 2014/15 Submission vs 2015/16 CARIN Methodology

Category	14/15	15/16	Reason
2.2.1 C25 Expenditure	Estimated	Actual	DMA process governance
2.2.1 C20 Expenditure	Estimated	Actual	DMA process governance
2.2.1 SCADA Expenditure	Estimated	Actual	DMA process governance
2.2.1 Pole Staking Expenditure	Estimated	Actual	DMA process governance
2.2.1 C25 Volumes	Estimated	Actual	DMA process governance
2.2.1 C20 Volumes	Estimated	Actual	DMA process governance
2.2.1 SCADA Volumes	Estimated	Actual	DMA process governance
2.2.1 Pole Staking Volumes	Estimated	Actual	DMA process governance

- Comparing to previous year 2014/15, this year 2015/16 Repex submission was done using DMA solution which had following advantages where Energex was in progress of developing in year 2014/15

- DMA – RIN Solution process governance
- Data transparency and repeatability
- Repex data and report can be produced periodically (monthly, quarterly, half yearly and annually).

- Annual Stock code review added new ones and reviewed few existing stock codes so they mapped correctly to the respective Repex asset category.
- In 2014/15, for each top project, the total expenditure including Repex asset category material expenditure was apportioned. This resulted in skewered actual Repex material expenditure for 2014/15. In 2015/16, this issue has been identified and the apportionment methodology has been reviewed to exclude Repex asset category material expenditure from apportioning and allocate directly to the respective Repex asset category in the Repex Template. This resulted in accurate actual Repex asset category materials spend for 2015/16 and also consistent with 2.12 input table for Repex Material Expenditure.
- In 2014/15, for C25 volumes, the material transaction date was assumed as commissioned date for the respective material, In 2015/16, after in depth analysis, it has been found that, after the material electrically commissioned, the work order for respective material will be closed within one week interval. Therefore the material work order close is more accurate representation of material commission date compare to 2014/15 assumption which is material transaction date.
- In 2014/15, for C20 projects, the commissioned data for respective material had been analysed manually using several project documentation. In 2015/16, RIN DMA solution has been developed to ensure the material commission date (in-service date) will be obtained from ELLIPSE through DMA solution which is transparent and repeatable.

3. BoP 2.2.2 - Repex Asset Failures by Category

The AER requires Energex to provide asset failure volumes for the 2015/16 Regulatory year in RIN table 2.2.1 for the following asset groups:

- **Poles, disaggregated by highest operating voltage and material type**
- **Pole top structures, disaggregated by highest operating voltage**
- **Overhead conductors, disaggregated by highest operating voltage and number of phases**
- **Underground cables, disaggregated by highest operating voltage**
- **Service lines, disaggregated by connection voltage, customer type and connection complexity**
- **Transformers, disaggregated by mounting type, highest operating voltage, ampere rating and number of phases**
- **Switchgear, disaggregated by highest operating voltage and switch function**
- **Public lighting, disaggregated by asset type and lighting obligation**
- **SCADA, network control and protections systems, disaggregated by function**

Actual Information was provided for all components of submitted data.

These variables are a part of Regulatory Template 2.2 – Repex.

3.1 Consistency with CA RIN Requirements

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

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The number of asset failures must be reported against the Asset Category. An asset failure is defined as the failure of an asset to perform its intended function safely and in compliance with jurisdictional regulations. It excludes external impacts such as: • extreme or atypical weather events • third party interference, such as traffic accidents and vandalism • wildlife interference, but only where the wildlife interference directly, clearly and unambiguously influenced asset performance • vegetation interference, but only where the vegetation interference directly, clearly and unambiguously influenced	Demonstrated in section 3.3 (Methodology)

Requirements (instructions and definitions)	Consistency with requirements
asset performance It also excludes planned interruptions.	

3.2 Sources

Table 3.2 below sets out the sources from which Energex obtained the required information.

Table 3.2: Information sources

Variable	Source
Poles Failures	In-service Pole Failure Register
Pole Top Structures Failures	EPM
Overhead Conductors Failures	EPM
Underground Cables Failures	EPM
Service Lines Failures	EPM
Transformers Failures (110kV/132kV/33kV) (Distribution Transformer)	Power Transformer Issues Register EPM
Switchgear Failures(>= 33kV Circuit Breakers) (All other types)	Network Investigation Report EPM
Public Lighting	Ellipse, Report Explorer, Intrinsic Energy Activity Database
SCADA	Ellipse

3.3 Methodology

- Failure data was extracted from the relevant source systems for each Asset Category for the current reporting period and filtered to ensure only inherent functional failures were included. This was achieved by excluding particular failure codes, using key word searches and analysing failure descriptions. Each failure event has the date recorded, enabling it to be counted in the appropriate year.

3.3.1 Assumptions

- For Overhead Conductor, Underground Cable and Service Line Asset failures, the quantity of failure events in the year is reported, not the length of failed asset.
- For street light luminaires and lamps, asset replacement volumes were used as a proxy for asset failures. Whilst some of the replacements will be based on asset failures, this information is not reported in Energex's systems.

3.3.2 Approach

- A level of consistency in data extraction and filtering was maintained wherever practically possible throughout the reporting process.
- For each Asset Group, the failures data was extracted from the source systems into a central working folder ("AER_CA_RIN_Asset Failures 2015-16"). A separate folder for each Asset Group was created beneath the central working folder, and a worksheet was created using the failures data. Each worksheet was filtered for the Asset Category to derive the number of failures. The individual worksheets contain the specific Asset Category information sorted by highest operating voltage – this ensured that any filtering criteria used were clearly visible in each worksheet.

Poles Failures

- All in-service pole functional failures are investigated and recorded in a pole failure register by the Asset Lifecycle Management Group within Asset Management. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further analysis.
- In-service functional failure of street light poles is also recorded under Poles failures.
- The filtered spreadsheet was included in the central working folder. The data was collated for each of the relevant sub-categories in the RIN table 2.2.1.

Pole Top Structures Failures

- The major source of in-service failures for pole top structures is due to the failure of crossarms. Crossarm failures are reported in the corporate performance reporting system EPM. An EPM report was developed to provide crossarm failures by line voltage level, as required in RIN table 2.2.1.
- The filtered spreadsheet was included in the central working folder. The data was collated for each of the relevant sub-categories in the RIN table 2.2.1.

Overhead Conductors Failures

- Overhead conductor failure outage data for the period 01/07/2015 to 30/06/2016 was extracted from the EPM report and placed in the central working folder. Failure outage data based on specific cause codes (e.g. third party, vegetation, weather, underground, substation, wildlife, etc.) was excluded. Any outage data with an underground cause code or a part code indicating underground or crossarm was also excluded.

- The data was analysed in detail by examining the ‘fault’ description and ‘action taken’ description entered by the Network Operator. All of the failure data was analysed in detail, with an additional ‘FLAG’ column added to the spreadsheet to indicate whether the data was to be included or excluded (any data that was erroneous was not included in the filtered spreadsheet view).
- The total asset failures were then collated for each of the relevant sub-categories in RIN table 2.2.1.

Underground Cables Failures

- Underground conductor failure outage data for the period 01/07/2015 to 30/06/2016 was extracted from the EPM report and also placed in the central working folder. Filtering techniques involved the inclusion of data containing the specific cause code for underground equipment failure (this excludes for example: third party, vegetation, weather, substation, wildlife). It must be noted that failures of pillars were not included as underground cables failures.
- The data was analysed in detail by examining the ‘fault’ description and ‘action taken’ description entered by the Network Operator. All of the failure data was analysed in detail, with an additional ‘FLAG’ column added to the spreadsheet to indicate whether the data was to be included or excluded (any data that was erroneous was not included in the filtered spreadsheet view).
- The total asset failures were then collated for each of the relevant sub-categories in RIN table 2.2.1.

Service Lines Failures

- Service line failure data for the period 01/07/2015 to 30/06/2016 was extracted from the EPM report and also placed in the central working folder. Due to the specific cause codes for Service Lines (Network - Repair Active Service Tail, Network - Repair Neutral Service Tail, Network - Replaced Service, Network - Replaced Service Fittings), additional filtering was unnecessary as this naturally excludes for example: third party, vegetation, weather, substation, and wildlife.
- The total asset failures were then collated for each of the relevant sub-categories in RIN table 2.2.1.

Transformers Failures

- For 11 kV distribution transformer failures; outages involving in-service failure data are identified in EPM for the period 01/07/2015 to 30/06/2016. This data was included in the central working folder. The initiating component identifier was used to filter for the relevant outages. The outages already included in previous reports were also removed from consideration. The remaining filtered failure data was analysed in detail, with an additional ‘FLAG’ column added to the spreadsheet to indicate whether the data was to be included or excluded. The total asset failure figures were then collated for each of the relevant sub-categories in RIN table 2.2.1.

- Power transformer asset failures in the primary voltage range 132 kV to 33 kV are collected after investigation and recorded in the Power Transformer Issues Register by the Asset Lifecycle Management Group within Asset Management. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further analysis. This data was included in the central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in RIN table 2.2.1.

Switchgear Failures

- All in-service circuit breakers failures are investigated and recorded in the Network Investigations Report Register by the Asset Lifecycle Management Group within Asset Management. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further analysis. This data was extracted into the central working folder to collate the total asset failures for each of the relevant sub-categories in RIN table 2.2.1.

- For switchgear failures, outages involving in-service failure data are identified in EPM for the period 01/07/2015 to 30/06/2016. This data was included in the central working folder. The outages already included in other categories were filtered out. All of the filtered failure data was analysed in detail, with an additional 'FLAG' column added to the spreadsheet to indicate whether the data was to be included or excluded. The total asset failures were then collated for each of the relevant sub-categories in RIN table 2.2.1.

Public Lighting Failures

- For public lighting luminaire failures, all replacements undertaken by streetlighting maintenance contractor Intrinsic Energy with a failure mode indicating the luminaire has been identified as no longer operational have been included. Failure data based on third party cause codes (e.g. storm, vandalism.) was excluded.

- For public lighting lamp failures, all replacements undertaken by streetlighting maintenance contractor Intrinsic Energy indicating the lamp has been replaced, and identified with the following drivers have been included:

    - a replacement driver of either end of life

    - a fault driver of either inoperative, flickering or cycling

    - did not require a luminaire replacement

  Failure data based on third party cause codes (e.g. storm, vandalism.) was excluded.

- The data for actual number of failures is extracted from Streetlighting maintenance contractor Intrinsic Energy monthly Activity Report. The maintenance data is captured at site in conjunction with the completion each activity utilizing the contractors electronic work dispatching/updating device. This data is then uploaded into their database and utilized for reporting and billing purposes.

- This contract constitutes the bulk of the maintenance work on lights in the Energex network, with lighting maintenance undertaken by internal staff only for the remote towns of Boonah, Gatton & Esk.

(A failure of a street light pole is contained under Poles Failures.)

Public Lighting Failures - Brackets

- The volume of public lighting bracket failures was reported as nil for each year on the basis that Energex has not reported any brackets failures during the reporting period.

SCADA, Network Control and Protection Systems Failures

- Failure rates for SCADA, Network Control and Protection Systems assets were obtained by evaluating repair work orders. The process commenced by extracting a list of all work orders relating to the failure of service / equipment from Ellipse. If the work order showed there was a loss of function of an asset, this was categorised as an asset failure and allocated against an appropriate asset category in the year in which it occurred. Data at the work order level was then collated to provide the total number of asset failures for each asset category for the 20115/16 regulatory year

3.4 Estimated Information

There is no estimated information for this template.

3.4.1 Justification for Estimated Information

Not applicable.

3.4.2 Basis for Estimated Information

Not applicable.

4. BoP 2.2.3 - Repex Asset Characteristics

The AER requires Energex to provide the following information in RIN table 2.2.2 – Selected Asset Characteristics:

Asset volumes currently in Commission and Asset Replacements for:

- **Total Poles By: Feeder Type**
- **Overhead Conductors By: Conductor Length By Feeder Type**
- **Overhead Conductors By: Conductor Length Material Type**
- **Underground Cables By: Cable Length By Feeder**
- **Transformers By: Total MVA**

Actual Information was provided for asset volumes currently in commission for each category and for all transformer asset replacements.

All other asset replacement figures are Estimated Information.

These variables are a part of Regulatory Template 2.2 – Repex.

4.1 Consistency with CA RIN Requirements

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

Table 4.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide total volume of assets currently in commission and replacement volumes of certain asset groups by specified aggregated metrics. In instances where this information is estimated Energex must explain how it has determined the volumes, detailing the process and assumptions used to allocate asset volumes to the aggregated metrics.	This requirement was addressed in the preparing RIN table 2.2.2

4.2 Sources

Table 4.2 sets out the sources from which Energex obtained the required information:

Table 4.2: Information sources

Variable	Source
Assets Volumes Currently in Commission	

Variable	Source
Total Poles By: Feeder Type	DMA/GIS
Overhead Conductors By: Conductor Length By Feeder Type	DMA
Overhead Conductors By: Conductor Length Material Type	DMA
Underground Cables By: Cable Length By Feeder	DMA
Transformers By: Total MVA	DMA
Asset Replacements	
Total Poles By: Feeder Type	Other variables within Tables 2.2.1 and 2.2.2.
Overhead Conductors By: Conductor Length By Feeder Type	Other variables within Tables 2.2.1 and 2.2.2.
Overhead Conductors By: Conductor Length Material Type	Other variables within Tables 2.2.1 and 2.2.2.
Underground Cables By: Cable Length By Feeder	Other variables within Tables 2.2.1 and 2.2.2.
Transformers By: Total MVA	DMA

4.3 Methodology

4.3.1 Assumptions

Asset Volumes Currently in Commission

Total Poles By: Feeder Type

- The pole data does not include assets that are in store or held for spares.
- The pole data does not include Streetlight poles of a material of Steel or Aluminium. There are159,144 of 607,018 poles that are Streetlights

  This only includes poles that are In Service and Inferred In Service (poles that are non-spatial are not included).

Overhead Conductors by: Conductor Length by Feeder Type

- The overhead conductor data does not include assets that were in store or held for spares.
- Feeder type will be derived from the feeder category.

Overhead Conductor by: Conductor Length Material Type

- The overhead conductor data does not include assets that were in store or held for spares.
- Only one conductor type can exist per span.

Underground Cable by: Cable Length by Feeder Type

- The underground cable data does not include assets that were in store or held for spares.
- Feeder type will be derived from the feeder category.

Transformer by: Total MVA

- All data derived from DMA which is generally not the usual source for all capacity data. This is because the usual system, SIFT, is used for sub-transmission capacity, however this system is unable to determine replacement and disposal information.

Asset Replacements

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

- feeder classification and material type:
  - Total Poles By: Feeder Type;
  - Overhead Conductors By: Conductor Length By Feeder Type;
  - Overhead Conductors By: Conductor Length Material Type; and
  - Underground Cables By: Cable Length by Feeder.
- Replacement of Power Transformers will have a material effect on the values reported.

POWER TRANSFORMERS (MVA)	***2015/16***
TOTAL MVA REPLACED	160
TOTAL MVA DISPOSED OF	85

4.3.2 Approach

Energex applied the following approach to obtain the required information:

The RIN Configuration Solution data Profiling types:

a. Global Prorata – This process involves taking all poles with complete information and generating a profile for all the Pole outcomes. Poles then with missing information are allocated across the all possibilities based on the percentages generated by the profile.

b. Prorata – The data is found in a particular group i.e. Poles dated pre 1920. A profile is then created based on the data found at the destination of the Prorated data i.e. 1970 through to 1999. The data is then distributed across the range based on the Profile.

c. Lookup Profile – A profile is generated and loaded in the solution which can be applied over the Data.

Asset Volumes Currently in Commission

Total Poles By: Feeder Type

1) Core information was extracted from DMA Reports.
   a. Current feeder categories were used to determine the feeder category.
   b. LV network inherited the feeder category of the 11kV feeder delivering the supply to the network.
   c. Voltages higher than 11KV were not included as they are not allocated a feeder Category.
2) The extract was from the DMA RIN Reports:
   a. All sites with a grade code of W were excluded as W sites are customer owned sites.
   b. Plastic Poles were also excluded (24 Poles in total).
   c. Streetlight poles with a material type of Steel or Aluminium (159,144 Poles in total)
3) Results were extracted to Excel file Pole_SITE_list_2016.xlsx
4) Overhead routes were assigned feeder categories based snapshot taken at the end of the financial year 2015/16.

a. Where Routes had more than one feeder category, the pole inherited a category based on the following order:

    i. Urban

    ii. Rural

    iii. CBD(High Density)

5) Poles from Pole_SITE_list_2016.xlsx are Spatial joined to the Routes

    a. Poles and their routes were spatially mapped using GIS tool.

    b. Poles were linked to the closest route and inherit the feeder category from the route.

Overhead Conductors by: Conductor Length by Feeder Type

1) SRC_OVERHEAD is the source table, which contains snapshotted history.

2) A report was extracted from the RIN Configuration Solution in DMA:

    a. Conductors were not allocated an ownership value, which generally means that customer owned conductors were not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurred Energex captured these conductors. In addition, assets that were sold to customers and there are benefits in continuing to store this data the data was not removed from NFM.

    To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor was also customer owned and excluded.

Estimated Customer Conductor	*Quantity (km)*
Unknown Category	1.25
Urban	1.24
Rural	2.54

3) Within the report conductors with an unknown category (340.18 km) were pro-rated into categories CBD, Urban and Rural based on a Global Prorata.

Overhead Conductor By: Conductor Length Material Type

1) SRC_OVERHEAD is the source table, which contains snapshotted history.

2) A report was extract from the RIN Configuration Solution in DMA

    a. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these conductors captured. In addition assets that have been sold to customers and Energex believes there is a benefits to continue to store this data.

To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor was also customer owned and excluded.

Estimated Customer Conductor	*Quantity (km)*
AAAC	0
HDBC	0
ACSR	2.6
AAC	1.89

b. Only overhead conductors were extracted.

c. Where different conductor types existed for a single span the material with the maximum code value was used. Generally this will result in the following preference, affecting a non-material portion of conductors:

   i. OH conductor LV ABC

   ii. OH conductor Steel

   iii. OH conductor ACSR

   iv. OH conductor AAAC

   v. OH conductor AAC

   vi. OH conductor HDBC

d. OH Conductor ABC were split to OH conductor HVABC and OH conductor LV ABC as Energex has ABC used for LV and 11KV. The OH Conductor HV ABC was added to the total for OH Conductor AAC.

3) The detailed conductor types were manually rolled up to OH Conductor ABC, OH conductor Steel, OH conductor ACSR, OH conductor AAAC, OH conductor AAC, OH conductor HDBC

4) The detailed conductor types roll up allocation was then validated by the Maintenance Department to ensure data integrity.

5) Within the DMA RIN Configuration Solution, conductors with an unknown conductor type (25.84 km) have been pro-rated into categories OH conductor ABC, OH

conductor Steel, OH conductor ACSR, OH conductor AAAC, OH conductor AAC, OH conductor HDBC based on existing data.

Underground Cables by: Cable Length by Feeder Type

1) SRC_UNDERGROUND is the source table, which contains snapshotted history.

2) The Report was run from the RIN Configuration Solution in DMA

   a. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurred Energex captured these conductors. In addition, assets that were sold to customers and there are benefits in continuing to store this data the data was not removed from NFM.

   To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor was also customer owned and excluded.

Estimated Customer Cable	***Quantity (km)***
Unknown Category	0
Urban	10.99
Rural	2.92

3) Within the report cables with an unknown category (29.55 km) were pro-rated into categories CBD, Urban and Rural using a global Prorata.

Transformer By: Total MVA

1) SLOT_TR is the source table, which contains snapshotted history.

2) A report was run from the RIN Configuration Solution in DMA.

3) Current Capacity was the summation of all known Rated Outputs for the end of financial year 2015/16.

Asset Replacements

1) The following variables were calculated from values contained in RIN tables 2.2.1 and 2.2.2:

   a. Total Poles By: Feeder Type;

   b. Overhead Conductors By: Conductor Length By Feeder Type;

   c. Overhead Conductors By: Conductor Length Material Type; and

   d. Underground Cables By: Cable Length by Feeder.

2) Asset replacement volumes for the specific asset groups have been calculated by taking the total number of assets replaced from RIN table 2.2.1 and apportioning the replacements based on the asset volumes currently in commission from table 2.2.2. For example. The total number of poles of all voltages replaced in 2015/16 is spread between CBD, Urban; and Rural short poles based on the volumes currently in service.

Transformer By: Total MVA

1) SLOT_TR is the source table, which contains snapshotted history.

2) A report was run from the RIN Configuration Solution in DMA.

3) Report contained all distribution transformers installed under a Repex costing Category and all possible Power transformer candidates for the current financial year. The report contained details on current transformer capacity, previous capacity, Top Project Identifier and Cost Groupings.

    a) The Top Project and the Cost Grouping align with 2.2.1. This allowed the use of the same base information to identify which Transformers where installed under a Repex costing. Without this information it was not possible to identify Repex from other costing groups e.g. Augex in 2014/15.

4) Excel files were used to update power transformer details that were replaced under Repex works.

5) Both manually entered Power Transformer Data and automated Distribution MVA data were added together for the current financial year to populate the Replaced and Previous MVA for the Disposed.

4.4 Estimated Information

The following asset replacement volumes are Estimated Information:

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

These asset replacement volumes are considered Estimated Information due to the judgements made during the categorisation of the quantities.

We have also had regard to the correspondence issued to management by the Australia Energy Regulator on 21 July 2016 and 12 August 2016 clarifying the presentation requirement of information in the Regulatory Information Notice data templates, in particular the requirement to present information as estimated if the Energex is unable to provide actual Information.

4.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN tables 2.2.2. As such Energex was required to manually categorise each into the categories required.

Energex notes that replacement projects can be by nature have a combination of two or more of the zone attributes (CBD, Urban and rural). Energex systems and processes currently do not enable detailed zone attributes to be captured.

4.4.2 Basis for Estimated Information

Energex has estimated the replacement volumes for the specific asset groups *(Selected Asset Characteristics RIN Table 2.2.2)* based on the total volume of actual assets replaced as set out in RIN table 2.2.1 therefore it is the most reliable source of data for asset replacement volumes as per the AERs definitions. The RIN Configuration Solution was used to report on the 15/16 RIN reporting requirements. The RIN Configuration Solution developed by Energex provides a single source system (using actual source system data) transparency and repeatability. There are processes and governance for the RIN Configuration Solution to ensure integrity of data sourced via this reporting system.

Asset replacement volumes for the specific asset groups and metric sets have been calculated by taking the total number of assets replaced from RIN table 2.2.1 (reported as actuals) and then apportioning the appropriate replacement volume(s) across the categories in table 2.2.2. The actual asset volumes in commission are obtained from corporate systems which are contemporaneous and represent the best known network asset information. This same information is used by Energex for making asset lifecycle planning and investment decisions. Based on current business practice, and the fact there is no other valid alternative to source this specific metric set information, Energex's considers this represents the best estimate available as it uses actual data and disaggregates this to provide the best known asset information at the metric set (i.e. disaggregated) level.

4.5 Explanatory notes

Energex does not have any rural long feeders.

5. BoP 2.3.1 - Augex Subtransmission Descriptor Metrics

The AER requires Energex to provide the following information in RIN table 2.3.1 – Sub-Transmission Substations, Switching Station and Zone Substations (projects closed during 2015/16):

- **Substation ID**
- **Substation Type**
- **Project ID**
- **Project Type**
- **Project Trigger**
- **Voltage**
- **Substation Rating Normal Cyclic (MVA)**
- **Substation Rating Emergency (MVA)**

The AER requires Energex to provide the following information in RIN table 2.3.2 – Sub-Transmission Lines:

- **Line ID**
- **Project ID**
- **Project Type**
- **Project Trigger**
- **Voltage**
- **Route Line Length Added**

These figures forms part the of Regulatory Template 2.3 – Augex.

Actual Information is provided for the following columns:

- **Substation ID**
- **Substation Type**
- **Line ID**
- **Project ID**
- **Project Type**
- **Project Trigger**
- **Voltage**
- **Route Line Length Added**
- **Substation Rating Normal Cyclic (MVA)**
- **Substation Rating N-1 Emergency (MVA)**

5.1 Consistency with CA RIN Requirements

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

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Details around the development of the project list are covered in the Basis of Preparation under Section 6.3.2 Approach.
Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). As specified in the respective definitions of normal cyclic rating (for substations) and thermal rating (for lines and cables), Energex must provide its definition(s) of 'normal conditions' in the Basis of Preparation.	The calculations of capacity are based on normal conditions. Please refer to Section 5.3.1 Assumptions for the definition of normal conditions.
Energex must not include information for gifted assets.	Details around the development of the project list are covered in BoP 2.3.2 for Augex - Subtransmission - Cost Metrics under Section 6.3.2 Approach.
Energex must enter related party and non-related party contracts expenditures in the 'All related party contracts' and 'All non-related party contracts' columns, respectively. i. Expenditure figures inputted into the 'All related party contracts' and 'All non-related party contracts' columns do not contribute to the column that calculates the total direct expenditure on an Augex project ('Total direct expenditure'). ii. Energex must record all contract expenditure for Augex projects under the 'All related party contracts' and 'All non-related party contracts' columns. Energex must then allocate such contract expenditure to the appropriate 'Plant and equipment expenditure and volume' and 'Other expenditure columns. For example, if a non-related party contract involves expenditure on civil works, Energex must record that expenditure under the 'All non-related party contracts' and 'Other expenditure – Civil works' columns.	Details around the reporting of party and non-related party contracts expenditure is covered in BoP 2.3.2 for Augex – Substransmission – Cost Metrics under Section 6.3.2 Approach
Energex must not include augmentation information relating to connections in this Regulatory Template.	Details around the development of the project list are covered in BoP 2.3.2 for Augex - Subtransmission - Cost Metrics

Requirements (instructions and definitions)	Consistency with requirements
	under Section 6.3.2 Approach.
For Table 2.3.1: "For projects with a total cumulative expenditure over the life of the project of greater than or equal to $5 million (nominal):" (i) insert a row for each augmentation project on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred at any time in the years specified; and (ii) input the required details. For Table 2.3.2 (iii) insert a row for each augmentation project on a subtransmission line owned and operated by Energex where project close occurred at any time during the years specified; and (iv) input the required details.	Details around the development of the project list are covered in BoP 2.3.2 for Augex - Subtransmission - Cost Metrics under Section 6.3.2 Approach.
For projects with a total cumulative expenditure over the life of the project less than $5 million (nominal) (non-material projects): For Table 2.3.1 (i) input the total expenditure for all non-material augmentation projects on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred in the years specified in the penultimate row in the table, as indicated. For Table 2.3.2 (ii) input the total expenditure for all non-material augmentation projects on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred in the years specified in the penultimate row in the table, as indicated.	Details around the development of the project list are covered in BoP 2.3.2 for Augex - Subtransmission - Cost Metrics under Section 6.3.2 Approach.
Energex must record all expenditure data on a project close basis in real dollars ($2012–13). Energex must not	Details around the development of the project list are covered in BoP 2.3.2 for

Requirements (instructions and definitions)	Consistency with requirements
include data for augmentation works where project close occurs after the years specified but incurs expenditure prior to this date.	Augex - Subtransmission - Cost Metrics under Section 6.3.2 Approach.
In relation to RIN table 2.3.1: (d) For the avoidance of doubt, this includes augmentation works on any substation in Energex 's network, including those which are notionally operating at transmission voltages. In such cases, choose 'Other - specify' in the 'Substation type' category and describe the type of substation in the basis of preparation. (e) Each row must represent data for an augmentation project for an individual substation. i. If an augmentation project applies to two substations, for example, Energex must enter data for the two substations in two rows. (f) Where a substation augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation. (g) Where Energex chooses 'Other – specify' in a drop down list, it must provide details in the basis of preparation document(s). (h) For 'Substation ID' and 'Project ID', input Energex's identifier for the substation and project, respectively. This may be the substation/project name, location and/or code. (i) For 'Project trigger', choose the primary trigger for the project from the drop down list. Describe secondary triggers in the Basis of Preparation. Where there is no primary trigger (among multiple triggers), choose 'Other – specify' and describe the triggers in the Basis of Preparation. (j) For substation voltages, enter voltages in the format xx/xx, reflecting the primary and secondary voltages. For example, a transformer may have its voltage recorded as 500/275, where 500kV is the primary voltage and 275kV is the secondary voltage. Where a tertiary voltage is applicable, enter voltages in the format xx/xx/xx. For example, a transformer may have its voltage recorded as 220/110/33, where 220kV, 110kV and 33kV are the primary, secondary and tertiary voltages, respectively. (k) For substation ratings, 'Pre' refers to the relevant characteristic prior to the augmentation work; 'Post'	(d) Please refer to section 5.3.2 - Approach – Voltage and Substation Type (e) Data has been entered in accordance with instructions (f) Please refer to Table 5.5: Substation Projects with Feeder Components (g) Please refer to section 5.3.2 - Approach - Project Type (h) Please refer to section 5.3.2 - Approach - Substation ID and Project ID (i) Please refer to section 5.3.2 - Approach – Project triggers (j) Data has been entered in accordance with instructions (k) Data has been entered in accordance with instructions

Requirements (instructions and definitions)	Consistency with requirements
refers to the relevant characteristic after the augmentation work. Where a rating metric does not undergo any change, or where the project relates to the establishment of a new substation, input the metric only in the 'Post' column. Under 'Total expenditure' for transformers, switchgear, capacitors, and other plant items, include only the procurement costs of the equipment. This must not include installation costs.	Details around the reporting expenditure on materials is covered in BoP 2.3.2 for Augex – Substransmission – Cost Metrics under Section 6.3.2 Approach
In relation to RIN table 2.3.2: (d) For the avoidance of doubt, this includes augmentation works on any subtransmission line in Energex's network. If Energex owns and operates any lines or cables notionally operating at transmission voltages, record any augmentation expenditure relating to such lines or cables in this table.	(d) Please refer to section 5.3.2 - Approach – Voltage
(e) Each row should represent data for all circuits of a given voltage subject to augmentation works under the Project ID. (i) If an augmentation project applies to two circuits of the same voltage, for example, Energex must enter data for the two circuits in one row. (ii) If an augmentation project applies to two circuits of different voltages, for example, Energex must enter data for the two circuits in two rows	(e) Data has been entered in accordance with instructions
(f) Where a subtransmission lines augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation.	(f) Please refer to Table 5.5 Substation Projects with Feeder Components
(g) Where Energex chooses 'Other - specify' in a drop down list, provide details in the basis of preparation.	(g) Please refer to section 5.3.2 - Approach - Project type
(h) For 'Line ID', input Energex's identifier for the circuit(s) subject to augmentation works under the Project ID. This may be the circuit name(s), location and/or code.	(h) Please refer to section 5.3.2 - Approach - Line ID
(i) For 'Project ID', input Energex's identifier for the project. This may be the project name, location and/or code.	(i) Please refer to section 5.3.2 - Approach - Project ID
(j) For 'Project trigger', choose the primary trigger for the project from the drop down list. Describe secondary triggers in the basis of preparation. Where there is no primary trigger (among multiple triggers), choose 'Other – specify' and describe the triggers in	(j) Please refer to section 5.3.2 - Approach – Project triggers

Requirements (instructions and definitions)	Consistency with requirements
the basis of preparation. (k) For length metrics, 'km added' refers to the gross addition of the relevant length measure resulting from the augmentation work: This must not be net of line or cable removal. If the augmentation project includes line or cable removal, describe the amount in Basis of Preparation.	(k) Please refer to section 5.3.2 - Approach – Route Line Length Added Please refer to section 5.3.2 - Approach – Route Line Length Added
Under 'Total expenditure' for transformers, switchgear, capacitors, poles/towers, lines, cables and other plant items, include only the procurement costs of the equipment. This must not include installation costs.	Details around the reporting of material total expenditure is covered in BoP 2.3.2 for Augex – Substransmission – Cost Metrics under Section 6.3.2 Approach
Under 'Total expenditure' for civil works, do not include civil works expenditure related to poles/towers. As a guide, expenditure Energex may input under 'Other expenditure – Civil works' includes (but is not limited to) construction of access tracks, construction pads and vegetation clearance.	Details around the reporting of material total expenditure is covered in BoP 2.3.2 for Augex – Substransmission – Cost Metrics under Section 6.3.2 Approach
Expenditure inputted under the 'Land and easements' columns is mutually exclusive from expenditure that appears in the columns that sum to the 'Total direct expenditure' column. In other words, the 'Total direct expenditure' for a particular project must not include expenditure inputted into the 'Land and easements' columns.	Details around the reporting of material total expenditure is covered in BoP 2.3.2 for Augex – Substransmission – Cost Metrics under Section 6.3.2 Approach
If Energex records land and easement projects and/or expenditures as separate line items for regulatory purposes, select 'Other – specify' and note 'Land/easement expenditure' in the basis of preparation document(s). (i) Energex must input expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively. These costs include legal, stamp duties and cost of purchase or easement compensation payments.	Details around the reporting of material total expenditure is covered in BoP 2.3.2 for Augex – Substransmission – Cost Metrics under Section 6.3.2 Approach

5.2 Sources

As outlined in the Table 5.2, data was extracted from a number of primary sources:

Table 5.2: Information sources

Variable	Source
Project Type	Project Approval Report, Engineering Specification, Feasibility Study, Project Scope Statement
Project Trigger	Project Approval Report
Substation Rating	Project Approval Report, ERAT2
Route Line Length Added	Engineering Specification, Feasibility Study, Project Scope Statement, GIS, Simulation Models(verification only)
Substation ID	Project Approval Report
Substation Type	Project Approval Report, ERAT2
Voltage	Project Approval Report, ERAT2
Line ID	Project Approval Report

5.3 Methodology

5.3.1 Assumptions

Energex obtained the required information based on actual data as follows:

- Normal conditions is described as the system state where all plant are configured in its intended operational state, without planned or forced outages on any plant item.
- Zone substations include 110/11 kV, 33/11 kV substations and 33 kV regulator stations.
- Sub-transmission feeders include 132 kV, 110 kV and 33 kV feeders.
- Pre-project rating information is based on information obtained from planning approval reports, which may have been calculated based on previous plant rating methodologies.
- Post-project rating information is based on current plant rating methodologies.
- All ratings are based on Summer season.
- All newly established zone substations have no pre-project ratings.

- Substation projects consisting of subtransmission feeder works with less than a route length of 500m are not part of Table RIN 2.3.2 for sub-transmission lines.
- Regulators and switchgear installation works are defined as part of substation works even if it does not contribute to an increase or decrease in substation capacity. These projects are included in RIN table 2.3.1. A full list of projects that did not result in a change in capacity is shown in Table 5.7.
- Feeder works documented is based on the operated voltage of the feeder.

5.3.2 Approach

All information is sourced based on the AER's requirements. Figures are produced through manual review and cross referencing of sources identified above. The development of each value is explained below:

Augex Project List

- The Augex project list is compiled in line with requirements set out in the CA RIN. The development of the project lists is discussed in the Basis of Preparation for Augex expenditure figures (BoP 2.3.2).
- Only projects with total project expenditure greater or equal to $5m are included in the detailed portion of RIN table 2.3.1 and RIN table 2.3.2.
- The following projects are identified as closed in 15/16 financial year:

Project ID	Project ID
C0062187	C0077354
C0065092	C0082077
C0065225	C0094795
C0065333	C0012644
C0074512	C0117380
C0077211	C065303

Substation ID

- The details of which substation is augmented for each project is taken from the planning approval report and verified with SIFT. The Substation IDs provided are the three letter substation acronyms of the relevant substations.

Substation Type

- Zone Substations are classified as having a secondary voltage of 11 kV, this includes 33/11 kV, 110/11 kV and 132/11 kV substations. Bulk Supply Substations are classified as Sub-transmission Substations having a secondary voltage of 33 kV, this includes 110/33 kV and 132/33kV substations. Switching Stations are classified as substations where the substation does not transform voltage from one level to another.

- Based on the substation ID, the substation type is sourced from SIFT, where it classifies each substation to its substation type.

Project ID

- Energex project numbers generated by its enterprise system are used as the Project ID.

Line ID

- The Line ID is based on Energex feeder number acronyms. The ID reported is the current feeder number associated with the feeder works. Changes to feeder names are verified as per the project title and/or project scope. This is because feeder names can change as subsequent works are carried out.

- Based on the project, the line ID for each feeder works is sourced from the planning approval report and cross referenced to the current feeder ID in ERAT2.

Voltage

- The voltage allocated under RIN table 2.3.1 is based on the transformation voltage of the transformer. Hence, for a zone substation equipped with 110/11 kV transformers, the voltage would be entered as “110/11”. For a switching station, the rated voltage of the circuit breakers is used to determine the operating voltage of the switching station. Hence, for a 33 kV switchgear switching station site, the voltage would be entered as “33”.

- The voltage allocated under RIN table 2.3.2 is based on the construction voltage of the feeders. The project approval report provides an indication of the construction voltage, and ERAT2 provides an indication of the current operating voltage.

- Table 5.3 shows the voltage for feeders where “Other-Specify” is entered in RIN table 2.3.2:

Table 5.3: Voltage for Sub-Transmission Feeders Table 2.3.2

Project ID	Voltage (kV)	Project ID	Voltage (kV)
C0062187	33	C0074512	33
C0065225	33	C0077211	33
C0065303	33	C0082077	110 & 33
C0065333	33	C0117380	33

Project Trigger

- Project trigger is identified from the project approval report under the section 'Limitations of the Existing Network' which gives a detailed description of the type of network limitations such as demand growth or voltage issue as well as including secondary drivers such as refurbishment or reliability improvement. It also provides further details such as the load forecast graph and network utilisation. Apart from that, 'Impact of Doing Nothing' in the PAR summarises all the network limitations not complying with the applied service standards on the basis that no work is undertaken.
- The list of project with secondary and "other" type drivers and their descriptions can be seen in Table 5.4:

Table 5.4: Projects with Other Project Trigger or Secondary Drivers

Project ID	Other Project Triggers
C0062187	Project also addresses a voltage and reliability issue.
C0065092	Due to fault level constraint, the substation bus was run split which resulted in loss of supply to customers under an N-1 contingency. A decrease in substation capacity post project is due to two of the transformers being put into standby under the project. This project also addresses an 11kV switchgear refurbishment issue.
C0065303	Project also addresses a voltage and a reliability issue.
C0065333	Project primary driver was to address a reliability issue.
C0074512	Project also addresses a voltage constraint issue.
C0077211	Project also address a cable refurbishment issue.
C0117380	Project also addresses a reliability issue.

Project Type

- The ‘Recommended Development’ section of the Project Approval Report provides a high level scope of the project. The Project Scope Statement and Feasibility Study documents contain early drafts of the project scope. The Engineering Specification document produced by the design team contains the highest level of detail of the project scope. All of the documents above contain information that allows the determination of the Project Type.

- The Project Approval Report is the primary source in determining the project type. Other sources of information are also used where the Project Approval Report does not contain sufficient information, including Engineering Specification, Project Scope Statements and Feasibility Studies.

Route Line Length Added

- Route line length added for a feeder augmentation project is first obtained through the Engineering Specification under any ‘MAINS’ works, which included overhead feeders and underground cable work descriptions. When going through each project, important key words such as ‘feeder’, ‘mains’, ‘cable’ are searched through the whole document to ensure that no feeder works in the project is overlooked. The engineering specification however only reports the amount of cable/conductor length per core. The total route length would need to be equally proportioned based on a 3 core configuration and a single circuit (SCCT) or double circuit (DCCT) type arrangement. This provides a reference of how much conductor or cable is required for the augmentation.

- Other sources of information for the circuit/route length may include the ‘Scope of work’ in Project Scope Statement and Project Approval Report. The collated source of length data is then verified against Energex 33 kV SINCAL model, and the Energex corporate GIS systems.

- If the information differ between all sourced systems, the GIS model is used as the final result as it is based on corporate data for “as constructed” feeder works.

- There are instances where substation type projects consist of feeder augmentation works. These feeder components of these projects are also documented as a separate entry under RIN table 2.3.2.

- Table 5.5 shows substation projects which have feeder components entered in RIN table 2.3.2:

Table 5.5: Substation Projects with Feeder Components

Project ID	Augmentation
C0062187	New DCCT OH, Upgrade OH Line, New UG DCCT UG
C0065225	New DCCT OH, Upgrade OH Line, UG DCCT UG
C0065303	New DCCT UG
C0065333	New SCCT UG

- The length metrics “km added” is based on the gross addition of the relevant length measured resulting from the augmentation works. Among the list of projects, there are projects which involve removal of line or cable to accommodate for the installation of the new circuit. These projects are identified as per Table 5.6: Substation Projects with Recoverable Feeder Components below.

Table 5.6: Substation Projects with Recoverable Feeder Components

Project ID	Augmentation
C0062187	Recover OH sections
C0065225	Recover OH sections
C0077211	Recover three UG feeders

Substation Rating

- Substation Rating can be identified from the Project Approval Report under section ‘Limitations of the Existing Network’ which gives a detailed description of the type of network limitations, this includes the Pre-Project Rating. The Post-Project Rating are obtained from the current corporate databases ERAT2 and SIFT.
- SIFT substation ratings are based on the current rating methodology, and this takes into account of the load sharing capability between transformers to work out the true substation rating capability.
- Table 5.7 below details projects where transformers are removed as part of the project scopes:

Table 5.7: Substation projects which have transformers removal components

Project Number	Transformers Removed
C0062187	Removed 1x5/8 MVA 33/11kV transformer.
C0094795	Removed 1x5 MVA 33/11kV transformer.

5.4 Estimated Information

Not Applicable

5.4.1 Justification for Estimated Information

Not Applicable

5.4.2 Basis for Estimated Information

Not Applicable

6. BoP 2.3.2 - Augex Subtransmission Cost metrics

The AER requires Energex to provide the following information relating to RIN table 2.3.1 - Augex Asset Data - Subtransmission Substations, Switching Stations And Zone Substations:

- **Plant And Equipment Expenditure And Volume**
- **Other Expenditure**
- **Total Direct Expenditure**
- **Years Incurred**
- **All Related Party Contracts**
- **All Non Related Party Contracts**
- **Land And Easements**

The AER requires Energex to provide the following information relating to RIN table 2.3.2 - Augex Asset Data - Subtransmission Lines:

- **Plant And Equipment Expenditure And Volume**
- **Other Expenditure**
- **Total Direct Expenditure**
- **Years Incurred**
- **All Related Party Contracts**
- **All Non Related Party Contracts**
- **Land And Easements**

These variables forms part of the Regulatory Template 2.3 – Augex.

6.1 Consistency with CA RIN Requirements

Table 6.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes are reported.
Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). As specified in the respective definitions of normal cyclic rating (for substations) and thermal rating (for lines and cables), Energex must provide its definition(s) of 'normal conditions' in	Details around the definition of normal conditions are covered in BoP 2.3.1 for Augex – Subtransmission - Descriptor Metrics under Section 5.3.1

Requirements (instructions and definitions)	Consistency with requirements
the basis of preparation document(s).	
Energex must not include information for gifted assets.	No gifted assets included.
Energex must not include augmentation information relating to connections in this Regulatory Template. Augmentations in relation to connections are to be inputted in the connections Regulatory Template (Regulatory Template 2.5).	No connection expenditure is included as stated in the connections Regulatory Template.
Energex must enter related party and non-related party contracts expenditures in the 'All related party contracts' and 'All non-related party contracts' columns, respectively. i. Expenditure figures inputted into the 'All related party contracts' and 'All non-related party contracts' columns do not contribute to the column that calculates the total direct expenditure on an Augex project ('Total direct expenditure'). Energex must record all contract expenditure for Augex projects under the 'All related party contracts' and 'All non-related party contracts' columns. Energex must then allocate such contract expenditure to the appropriate 'Plant and equipment expenditure and volume' and 'Other expenditure columns. For example, if a non-related party contract involves expenditure on civil works, Energex must record that expenditure under the 'All non-related party contracts' and 'Other expenditure – Civil works' columns.	Only the "all non-related party contract" expenditure is reported as required in RIN Tables 2.3.1 and 2.3.2. There is no "related party contract" expenditure reportable.
Record all expenditure data on a project close basis in real dollars ($2012–13). Energex must not include data for augmentation works where project close occurs after the years specified but incurs expenditure prior to this date. Energex must provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.	Expenditure data is reported on project close basis in real dollars in $2015-16.
For projects with a total cumulative expenditure over the life of the project of greater than or equal to $5 million (nominal): For RIN table 2.3.1: (i) insert a row for each augmentation project on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred at any time in the years specified; and (ii) input the required details. For RIN table 2.3.2:	Only projects equal to or greater than $5 million direct nominal expenditure over the life of the project is reported. Data is entered in accordance with the instructions.

Requirements (instructions and definitions)	Consistency with requirements
(i) insert a row for each augmentation project on a subtransmission line owned and operated by DNSP where project close occurred at any time during the years specified; and (ii) input the required details.	
For projects with a total cumulative expenditure over the life of the project less than $5 million (nominal) (non-material projects): For RIN table 2.3.1: (i) input the total expenditure for all non-material augmentation projects on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred in the initial regulatory years in the penultimate row in the regulatory template, as indicated. For RIN table 2.3.2: input the total expenditure for all non-material augmentation projects on subtransmission lines owned and operated by Energex where project close occurred in the initial regulatory years in the penultimate row in the regulatory template, as indicated	Projects with less than $5 million nominal expenditure over the life of the project are consolidated into the expenditure figures shown in the penultimate row of each table.
For RIN table 2.3.1: Each row must represent data for an augmentation project for an individual substation. (i) If an augmentation project applies to two substations, for example, Energex must enter data for the two substations in two rows. For RIN table 2.3.2: Each row should represent data for all circuits of a given *voltage* subject to *augmentation* works under the Project ID. (i) If an augmentation project applies to two circuits of the same voltage, for example, Energex must enter data for the two circuits in one row. (ii) If an augmentation project applies to two circuits of different voltages, for example, Energex must enter data for the two circuits in two rows	Data has been entered in accordance with instructions.
For RIN table 2.3.1: For 'Substation ID' and 'Project ID', input Energex's identifier	Details around the reporting of Substation ID, Project ID and Line ID

Requirements (instructions and definitions)	Consistency with requirements
for the substation and project, respectively. This may be the substation/project name, location and/or code. For RIN table 2.3.2: For 'Line ID', input Energex's identifier for the circuit(s) subject to augmentation works under the Project ID. This may be the circuit name(s), location and/or code. For 'Project ID', input Energex's identifier for the project. This may be the project name, location and/or code.	are covered in BoP 2.3.1 for Augex – Subtransmission - Descriptor Metrics under Section 5.3.2 Approach.
For RIN table 2.3.2: For length metrics, 'km added' refers to the gross addition of the relevant length measure resulting from the augmentation work: This must not be net of line or cable removal. If the augmentation project includes line or cable removal, describe the amount in Basis of Preparation.	Details around the reporting of the length metrics are covered under BoP 2.3.1 for Augex Subtransmission – Descriptor Metrics under Section 5.3.2 - Approach – Route Line Length Added
For 'Project trigger', choose the primary trigger for the project from the drop down list. Describe secondary triggers in the Basis of Preparation. Where there is no primary trigger (among multiple triggers), choose 'Other – specify' and describe the triggers in the Basis of Preparation.	Details around the reporting of 'Project Trigger' are covered in BoP 2.3.1 for Augex – Subtransmission - Descriptor Metrics under Section 5.3.2 Approach.
For RIN table 2.3.1: For substation voltages, enter voltages in the format xx/xx, reflecting the primary and secondary voltages. For example, a transformer may have its voltage recorded as 500/275, where 500kV is the primary voltage and 275kV is the secondary voltage. Where a tertiary voltage is applicable, enter voltages in the format xx/xx/xx. For example, a transformer may have its voltage recorded as 220/110/33, where 220kV, 110kV and 33kV are the primary, secondary and tertiary voltages, respectively.	Details around the reporting of substation voltage are covered in BoP 2.3.1 for Augex – Subtransmission - Descriptor Metrics under Section 5.3.2 Approach.
For RIN table 2.3.1: For substation ratings, 'Pre' refers to the relevant characteristic prior to the augmentation work; 'Post' refers to the relevant characteristic after the augmentation work. Where a rating metric does not undergo any change, or where the project relates to the establishment of a new substation, input the metric only in the 'Post' column.	Details around the reporting of substation ratings are covered in BoP 2.3.1 for Augex – Subtransmission - Descriptor Metrics under Section 5.3.2 Approach.

Requirements (instructions and definitions)	Consistency with requirements
For RIN table 2.3.1: Under 'Total expenditure' for transformers, switchgear, capacitors, and other plant items, include only the procurement costs of the equipment. This must not include installation costs. For RIN table 2.3.2: Under 'Total expenditure' for *poles/towers*, include the procurement costs of the equipment and *civil works*. This must not include installation costs.	Installation costs are reported separately in each table with the material expenditure only reported for under the total expenditure for material.
Expenditure inputted under the 'Land and easements' columns is mutually exclusive from expenditure that appears in the columns that sum to the 'Total direct expenditure' column. In other words, the 'Total direct expenditure' for a particular project must not include expenditure inputted into the 'Land and easements' columns.	Total direct expenditure does not include any material type expenditure for land or easements.
If Energex records land and easement projects and/or expenditures as separate line items for regulatory purposes, select 'Other – specify' and note 'Land/easement expenditure' in the basis of preparation document(s).	No Land and easement projects greater than $5m are included in 2015-16.
Energex must input expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively. These costs include legal, stamp duties and cost of purchase or easement compensation payments.	Data has been entered in accordance with instructions.
Where a substation or subtransmission lines augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation.	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information.
Where Energex chooses 'Other – specify' in a drop down list, it must provide details in the basis of preparation document(s).	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information.

6.2 Sources

Table 6.2 sets out the sources from which Energex obtained the required information.

Table 6.2: Information sources

Variable	Source
All variables	DMA RIN

6.3 Methodology

All figures for RIN tables 2.3.1 and 2.3.2 are calculated by identifying the Energex projects that fit the criteria related to subtransmission Augex. Each of these projects is then classified as either material or non-material based on the expenditure threshold as per the instructions. The transactions against each material project are then analysed in order to report against the required categories in RIN tables 2.3.1 and 2.3.2.

6.3.1 Assumptions

Energex applied the following criteria to obtain the required information:

- Subtransmission lines projects equal to or greater than the nominal $5M cumulative direct expenditure must include material amount of subtransmission lines works. Please refer to the “Project Description and Changes” Basis of Preparation for further details;
- In RIN table 2.3.1 “other plant items” includes subtransmission line material costs detailed in RIN Table 2.3.2 where applicable;
- In RIN table 2.3.2 “other plant items” includes zone and bulk supply material costs detailed in RIN Table 2.3.1 where applicable;
- Installation labour in RIN table 2.3.1 includes cable installation labour;
- Installation labour is allocated based on work activity type;
- Installation volume in RIN table 2.3.1 is the sum of labour hours for the substation assets installed;
- Installation volume in RIN table 2.3.2 is the sum of labour hours for the circuit length installed.
- Design and construction contracts are spread over installation labour, civil works and other direct costs;
- Nominal costs are escalated based on CPI sourced from ABS;
- Cost components of each project are escalated based on a single escalation value calculated for each project;
- Number of poles upgraded is dependent on the driver of the project;

- Feeder re-conductoring works, conductor re-tensioning, pole upgrades, and feeders that are re-energised to higher voltage levels are deemed to be classified as subtransmission upgrades.
- Related party margins are zero; and
- For strategic land purchased, the project type and project trigger are listed as "Other Specify".

6.3.2 Approach

Project List Development

1) A report is run from DMA RIN which lists all projects closed within the regulatory year 2015/16, under the Augex financial activity codes in Table 6.3:

Table 6.3: Augex Financial Activity Codes for Projects Transactions in 2015/16

Activity Code	Description
C2020	Augmentation – Sub Transmission & 11kV Network
C2030	Reliability Improvement & Power Quality
C2050	Demand Primary Reliability Secondary
C2060	Augmentation – 11kV Network
C2070	Land & Right of Way
C2075	Easements
C2090	Engineering and Admin
C2095	Infrastructure Projects
C2099	Transmission PoW Efficiency
C2530	External Business Income
C2565	Augmentation – Distribution
C2566	Power Quality
C2580	Control & Metering
C2585	Load Control
C2590	Engineering and Admin

Activity Code	Description
C2595	Infrastructure Projects
C2599	Distribution PoW Efficiency

2) This report includes all Energex augmentation type projects based on its subtransmission plant items; excluding any gifted assets to Energex.

3) This list is then filtered for a cumulative nominal direct expenditure over the life of the project equal or greater than $5,000,000, and is reported as a separate project entry in the Regulatory Template.

4) The filtered list provides a breakdown of the expenditure in the different Augex categories; “subtransmission” or “subtransmission lines” to assist with the segregation of projects into its respective project type; a substation type project (for input into RIN table 2.3.1) or a subtransmission line project (for input into RIN table 2.3.2). Based on the breakdown, the material project could be reported within both tables if it incorporates both substation and line construction works.

5) Projects which have a total cumulative nominal direct project expenditure less than $5,000,000 are labelled as non-material projects and will be consolidated into a single substation line item in the RIN table 2.3.1 and a single subtransmission line item in RIN table 2.3.2.

6) This then gives the list of subtransmission projects reported.

Plant and Equipment Expenditure and Volumes

1) The measured cost expenditure for each project reported in RIN tables 2.3.1 and 2.3.2 is calculated based on the yearly costs for each project extracted from DMA RIN. In accordance with the AER’s RIN instructions, all closed project related expenditure data is to be reported in real dollars ($2015–16). Specifically, values must not include data for augmentation works where projects are to close after the specified years but incurs expenditure prior to this date. These yearly costs are multiplied by an escalation factor to convert the figures to a $2015-16 basis. The escalation factors are derived from the ABS CPI values that is based on the eight capital cities average and is shown in Table 6.4:

Table 6.4: Escalation Factors

Financial Year	Escalation Factor
2015-16	1.000
2014-15	1.017
2013-14	1.034
2012-13	1.065
2011-12	1.091
2010-11	1.109
2009-10	1.145
2008-09	1.179
2007-08	1.208
2006-07	1.259
2005-06	1.290
2004-05	1.328
2003-04	1.359
2002-03	1.386

2) DMA RIN is set up to provide detail expenses and quantities against each augmentation project to be used for the population of RIN tables 2.3.1 and 2.3.2 template.

3) Expenditure and volume data obtained from DMA RIN is based on the materials costs against each project. Each material expense is classified by a Stock Item Group Class (SIGC) which is mapped to a REPEX asset category and classified under its corresponding AUGEX group.

4) As every individual stock item is assigned to an Augex asset category classification, the DMA RIN system is able to extract expenditure and volume information for every project for the required subtransmission material components (transformer, switchgear, capacitor, underground cables, overhead lines, and poles). Table 6.5 and table 6.6 outline the grouping of asset categories as required for RIN table 2.3.1 and Table 2.3.2 respectively.

Table 6.5: Grouping of asset categories for RIN table 2.3.1

CA RIN Category – Table 2.3.1	Asset Categories
Transformers Units Added	Material quantity values within: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV<=15MVA • TR Grd>33kV<=66kV>15MVA<=40MVA

CA RIN Category – Table 2.3.1	Asset Categories
	• TR Grd>33kV<=66kV>40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA • TR Grd>132kV<=100MVA • TR Grd>132kV>100MVA
Transformers MVA Added	The summation of the material quantity value multiplied by the name plate rating within: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV<=15MVA • TR Grd>33kV<=66kV>15MVA<=40MVA • TR Grd>33kV<=66kV>40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA • TR Grd>132kV<=100MVA • TR Grd>132kV>100MVA
Transformers	The summation of the material expenses within: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV<=15MVA • TR Grd>33kV<=66kV>15MVA<=40MVA • TR Grd>33kV<=66kV>40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA • TR Grd>132kV<=100MVA • TR Grd>132kV>100MVA
Switchgear Units Added	Material quantity values within: • Switchgear<=11kV;CB • Switchgear>11kV<=22kV;CB • Switchgear>11kV<=22kV;Switch • Switchgear>22kV<=33kV;CB • Switchgear>22kV<=33kV;Switch • Switchgear>33kV<=66kV;CB • Switchgear>33kV<=66kV;Switch • Switchgear>66kV<=132kV;CB • Switchgear>66kV<=132kV;Switch • Switchgear>132kV;CB • Switchgear>132kV;Switch

CA RIN Category – Table 2.3.1	Asset Categories
Switchgear	The summation of the material expenses within: • Switchgear<=11kV;CB • Switchgear>11kV<=22kV;CB • Switchgear>11kV<=22kV;Switch • Switchgear>22kV<=33kV;CB • Switchgear>22kV<=33kV;Switch • Switchgear>33kV<=66kV;CB • Switchgear>33kV<=66kV;Switch • Switchgear>66kV<=132kV;CB • Switchgear>66kV<=132kV;Switch • Switchgear>132kV;CB • Switchgear>132kV;Switch •
Capacitors Units Added	Material quantity values within: • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Capacitors MVAR Added	The summation of material quantity multiplied by the rating within: • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Capacitors	The summation of expenses within: • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Other Plant Item	The summation of material expenses for all other asset categories excluding: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV<=15MVA • TR Grd>33kV<=66kV>15MVA<=40MVA • TR Grd>33kV<=66kV>40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA • TR Grd>132kV<=100MVA • TR Grd>132kV>100MVA • Switchgear<=11kV;CB • Switchgear>11kV<=22kV;CB

CA RIN Category – Table 2.3.1	Asset Categories
	• Switchgear>11kV<=22kV;Switch • Switchgear>22kV<=33kV;CB • Switchgear>22kV<=33kV;Switch • Switchgear>33kV<=66kV;CB • Switchgear>33kV<=66kV;Switch • Switchgear>66kV<=132kV;CB • Switchgear>66kV<=132kV;Switch • Switchgear>132kV;CB • Switchgear>132kV;Switch • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor

Table 6.6: Grouping of asset categories for RIN table 2.3.2

CA RIN Category – Table 2.3.2	Asset Category Filters Applied
Poles / Towers Added	Material quantity values within: • Pole>22kV<=66kV;Wood • Pole>66kV<=132kV;Wood • Pole>132 kV;Wood • Pole>22kV<=66kV;Concrete • Pole>66kV<=132kV;Concrete • Pole>132kV;Concrete • Pole>22kV<=66kV;Steel • Pole>66kV<=132kV;Steel • Pole>132kV;Steel Poles are allocated as either added or upgraded based on the main driver of the project
Poles / Towers Upgraded	
Poles/Towers Expenditure	The summation of material expenses within: • Pole>22kV<=66kV;Wood • Pole>66kV<=132kV;Wood • Pole>132 kV;Wood • Pole>22kV<=66kV;Concrete • Pole>66kV<=132kV;Concrete • Pole>132kV;Concrete • Pole>22kV<=66kV;Steel • Pole>66kV<=132kV;Steel • Pole>132kV;Steel

<table>
<tr><th>CA RIN Category – Table 2.3.2</th><th>Asset Category Filters Applied</th></tr>
<tr><td>Overhead Lines Circuit KM Added</td><td rowspan="2">Material quantity values within:
• OH Conductor>22kV<=66kV
• OH Conductor>66kV<=132kV
• OH Conductor>132kV

Overhead lines are allocated as either added or upgraded based on the main driver of the project</td></tr>
<tr><td>Overhead Lines Circuit KM Upgraded</td></tr>
<tr><td>Overhead Lines Expenditure</td><td>The summation of material expenses within:
• OH Conductor>22kV<=66kV
• OH Conductor>66kV<=132kV
• OH Conductor>132kV</td></tr>
<tr><td>Underground Cables Circuit KM Added</td><td rowspan="2">Material quantity values within:
• UG Cable>22kV<=33kV
• UG Cable>33kV<=66kV
• UG Cable>66kV<=132kV
• UG Cable>132kV

Underground cables are allocated as either added or upgraded based on the main driver of the project</td></tr>
<tr><td>Underground Cables Circuit KM Upgraded</td></tr>
<tr><td>Underground Cables Expenditure</td><td>The summation of material expenses within:
• UG Cable>22kV<=33kV
• UG Cable>33kV<=66kV
• UG Cable>66kV<=132kV
• UG Cable>132kV</td></tr>
<tr><td>Other Plant Item Expenditure</td><td>The summation of material expenses for all other asset categories excluding:
• Pole>22kV<=66kV;Wood
• Pole>66kV<=132kV;Wood
• Pole>132 kV;Wood
• Pole>22kV<=66kV;Concrete
• Pole>66kV<=132kV;Concrete
• Pole>132kV;Concrete
• Pole>22kV<=66kV;Steel
• Pole>66kV<=132kV;Steel
• Pole>132kV;Steel
• OH Conductor>22kV<=66kV
• OH Conductor>66kV<=132kV
• OH Conductor>132kV
• UG Cable>22kV<=33kV
• UG Cable>33kV<=66kV
• UG Cable>66kV<=132kV
• UG Cable>132kV</td></tr>
</table>

5) The remaining material and equipment expenditure which are not specified in RIN table 2.3.1 and 2.3.2 are then allocated under the "Other Plant Item – Expenditure" column.

6) The non-material expenditure of a project is then filtered within DMA RIN into its respective expenditure categories; installation labour, civil, contract and other direct expenditures. Table 6.7 below outlines the logic applied to the group of expenses and volumes into their intermediate expense categories.

7)

Table 6.7: Logic applied to group expenses

CA RIN Category	Logic Filter Applied
Installation Labour Expenditure and Volume	The summation of expenses related to project equipment installation and a third of the project's non-related party contract expenditure. • The Expenditure Element Cost Category ID is 'INTLAB • The work order Maintenance Type ID is not 'PL,DE,LE'
Civil	The summation of expenses related to project civil works and a third of the project's non-related party contract expenditure. • The text 'civil' appears in the Work Order Description • The text 'pit' appears in the Work Order Description • The text 'CV' appears in the Work Order Description
Other Direct Expenditure	The summation of all other expenditure, not relating to project civil works and equipment installation, and a third of the project's non-related party contracts. • All Other Non-Material cost that does not fall under the installation labour, civil and all non-related party contracts categories.
All Non-Related Party Contracts	The summation of expenses related to the project's non-related party contract expenditure. • The Expenditure Element Cost Category is "Contracts'
Land and Easement	The summation of expenses related land and easements. • The Expenditure Element Cost Category is "Materials' • The work order Maintenance Type ID is 'LE'

8) Consistent with AER's RIN instruction, contract expenditures have been allocated to the appropriate 'Plant and equipment expenditure and volume' and 'Other

expenditure columns. The contract expenditures are also separately reported under the 'All non-related party contracts' column. The formula for the total direct expenditure column within the RIN template does not include the data inputted under the 'All non-related party contracts' column, hence the contract expenditures are not double counted.

9) All other directly attributable land and easement expenditure (where applicable) are included under the 'Land and easements' column, other associated expenditure such as town planning or environmental assessment costs are included under 'other direct expenditure' column. Consistent with AER's instructions, expenditure inputted under the 'Land and easements' columns is mutually exclusive from expenditure that appears in the columns that sum to the 'Total direct expenditure' column.

10) As there are no transparency for Energex to breakdown the cost of turn-key design and construct contracts into civil, installation labour and other direct cost, the contract cost is allocated equally among the three categories in order for the cost to be reflected in the 'total direct expenditure' column of a project.

11) The total amount of subtransmission feeder materials (poles/tower, overhead lines and underground cables) of a project are extracted from actual financial transaction data. The classification of them into Addition or Upgraded has been done through analysis of feasibility study reports or engineering specifications - whichever represents the most recent information for the project. The units added or upgraded for each subtransmission feeder components of a project are apportioned based on the spread of subtransmission feeder materials outlined in the feasibility study report or engineering specification.

6.4 Estimated Information

6.4.1 Justification for Estimated Information

Not Applicable.

6.4.2 Basis for Estimated Information

Not Applicable.

6.5 Explanatory notes

Not Applicable.

7. BoP 2.3.3 – Augex - HV/LV Feeders and Distribution Substations

The AER requires Energex to provide the following information in RIN table 2.3.3.1 – Augex Data – HV/LV Feeders And Distribution Substations – Descriptor Metrics:

- **HV Feeder Augmentations - Overhead Lines (Circuit Line Length Km)**
- **HV Feeder Augmentations - Underground Cables (Circuit Line Length Km)**
- **LV Feeder Augmentations - Overhead Lines (Circuit Line Length Km)**
- **LV Feeder Augmentations - Underground Cables (Circuit Line Length Km)**
- **Distribution Substation Augmentations - Pole Mounted**
- **Distribution Substation Augmentations - Ground Mounted**
- **Distribution Substation Augmentations – Indoor**

The AER requires Energex to provide the following information relating to RIN table 2.3.3.2 – Augex Data – HV/LV Feeders And Distribution Substations – Cost Metrics:

- **HV Feeder Augmentations - Overhead Lines ($0's)**
- **HV Feeder Augmentations - Underground Cables ($0's)**
- **HV Feeder Non-Material Projects ($0's)**
- **LV Feeder Augmentations - Overhead Lines ($0's)**
- **LV Feeder Augmentations - Underground Cables ($0's)**
- **LV Feeder Non-Material Projects ($0's)**
- **Distribution Substation Augmentations - Pole Mounted ($0's)**
- **Distribution Substation Augmentations - Ground Mounted ($0's)**
- **Distribution Substation Augmentations - Indoor ($0's)**

These values are a part of Regulatory Template 2.3 – Augex.

7.1 Consistency with CA RIN Requirements

Table 7.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes are reported.
Energex must not include information for gifted assets.	No gifted assets are included.
Energex must not include augmentation information relating to connections in this Regulatory Template. Augmentations in relation to connections are to be inputted in the connections Regulatory Template (Regulatory Template 2.5).	No connection expenditure is included and it is stated in the connections Regulatory Template.

Requirements (instructions and definitions)	Consistency with requirements
For Table 2.3.3.2 – "Complete the table by inputting the required details for: i) the rows that summarise all augmentation works on the specified types of HV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of greater than or equal to $0.5 million (nominal); and the row that summarises all augmentation works on HV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of less than $0.5 million (nominal)"	HV feeder projects with greater than $0.5 million nominal expenditure over the life of the project are reported separately. Those with less than $0.5 million are input in the summary row.
For Table 2.3.3.2 – "Complete the table by inputting the required details for: i) the rows that summarise all augmentation works on the specified types of LV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of greater than or equal to $50,000 (nominal); and the row that summarises all augmentation works on LV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of less than $50,000 (nominal).	LV feeder projects with greater than $50,000 nominal expenditure over the life of the project are reported separately. Those with less than $50,000 are input in the summary row.
Record all expenditure data on an 'as incurred' basis in nominal dollars.	All project costs are stated in nominal dollars in the year incurred.
For projects that span across regulatory years, input figures for the 'Circuit km added' and 'Circuit km upgraded' columns according to the final year in which expenditure is incurred for the project.	Circuit km added and upgraded figures are input for projects closed in 2015-16
Energex must not include expenditure related to land purchases and easements in the 'Total direct expenditure' column. Land purchases and easements expenditure related to augmentation works on all LV feeders owned and operated by Energex must be inputted in Table 2.3.6.	Expenditure figures do not include any expenditure for land or easements. Land purchases and easements expenditure related to augmentation works on all LV feeders owned and operated by Energex are inputted in Table 2.3.4.

7.2 Sources

Table 7.2 sets out the sources from which Energex obtained the required information.

Table 7.2: Information sources

Variable	Source
All variables	DMA RIN
Classification of projects as Addition or Upgrade	Project Scope Statements, Planning Approval Reports, Feasibility Study, Engineering Specifications, Total Outturn Cost Approval, Construction Drawings

7.3 Methodology

All figures for RIN table 2.3.3.1 were sourced from the financial transactions recorded against all augmentation projects that were closed during the 2015-16 financial year. The materials booked to these projects were then used to calculate the number of units. A final logic is applied to determine if the units were added or upgraded based on the project description.

All figures for RIN table 2.3.3.2 were calculated based on the financial transactions recorded in the financial year. The transactions were filtered to obtain only augmentation related activities. The cumulative project costs of each of the relevant projects were then obtained and compared to the thresholds specified for each project type.

The population of RIN table 2.3.3.2 was completed by grouping the expenditure into the required project types as per the table.

7.3.1 Assumptions

Energex applied the following criteria to obtain the required information:

- The expenditure data is a subset of data in Table 2.3.4 categories “HV feeders”, “LV feeders” and “Distribution substations” where the data is further classified into the required categories in Table 2.3.3.2.
- Expenditure not relating to materials are apportioned across the augmentation capex categories based on the expenditure on materials for each project.

7.3.2 Approach

1) A report is run from DMA RIN which lists all projects closed within the regulatory year 2015/16, under the Augex financial activity codes in Table 7.3:

Table 7.3: Augex Financial Activity Codes for Project Transactions 2015/16

Activity Code	Description
C2020	Augmentation – Sub Transmission & 11kV Network
C2030	Reliability Improvement & Power Quality
C2050	Demand Primary Reliability Secondary
C2060	Augmentation – 11kV Network
C2070	Land & Right of Way
C2075	Easements
C2090	Engineering and Admin
C2095	Infrastructure Projects
C2099	Transmission PoW Efficiency
C2530	External Business Income
C2565	Augmentation – Distribution
C2566	Power Quality
C2580	Control & Metering
C2585	Load Control
C2590	Engineering and Admin
C2595	Infrastructure Projects
C2599	Distribution PoW Efficiency

2) This report includes all Energex augmentation type projects with financial transactions in FY2015/16. Gifted assets and connection assets are not included in the financial activity codes above.

3) The financial transactions are filtered to exclude any overheads applied to give the direct expenditure for each project.

4) Only projects with expenditure against HV feeder augmentations, LV feeder augmentations and distribution substation augmentations are selected.

Project Data Allocation

1) The mapping of assets to AER Augex asset categories is based on the analysis of stock items group class (SIGC) which are mapped to corresponding Repex asset categories classifications.

2) Entries of the AER asset category are then mapped to AUGEX categories in order to group and evaluate metrics for overhead cable, underground cable, and distribution transformer materials.

Table 7.4: Grouping of asset categories for RIN table 2.3.3

Augmentation Capex Category	REPEX asset category
HV Feeders Augmentations – Overhead Lines	Pole>1kV<=11kV;Wood Pole>11kV<=22kV;Wood Pole>1kV<=11kV;Concrete Pole>11kV<=22kV;Concrete Pole>1kV<=11kV;Steel Pole>11kV<=22kV;Steel Pole Top>1kV<=11kV Pole Top>11kV<=22kV OH Conductor>1kV<=11kV OH Conductor?11kV<=22kV;SWER OH Conductor?11kV<=22kV;Single-Phase OH Conductor?11kV<=22kV;Multiple-Phase Services<=11kV;C&I;Simple Type Services<=11kV;C&I;Complex Type Services<=11kV;Subdivision;Complex Type Services>11kV<=22kV;C&I Services>11kV<=22kV;Subdivision Switchgear<=11kV;Fuse Switchgear<=11kV;Switch Switchgear>11kV<=22kV;Switch Non REPEX Category >1kV <=11kV Regulator
HV Feeders Augmentations – Underground Cables	UG Cable>1kV<=11kV UG Cable>11kV<=22kV
LV Feeders Augmentations – Overhead Lines	Pole<=1kV;Wood Pole<=1kV;Concrete Pole<=1kV;Steel Pole Top<=1kV OH Conductor<=1kV Services<=11kV;Residential;Simple Type Services<=11kV;Residential;Complex Type
LV Feeders Augmentations – Underground Cables	UG Cable<=1kV

Augmentation Capex Category	REPEX asset category
Distribution Substations Augmentations – Pole Mounted	TR Pole<=22kV<=60kVA;One Ph Other TR Pole>22kV<=60kVA;One Ph Other TR Pole>22kV>60kVA<=600kVA;One Ph Other TR Pole>22kV>600kVA;One Ph Other TR Pole>22kV<=60kVA;Multi Ph Other TR Pole>22kV>60kVA<=600kVA;Multi P Other TR Pole>22kV>600kVA;Multi Ph TR Pole<=22kV>60kVA<=600kVA;One Ph TR Pole<=22kV>600kVA;One Ph TR Pole<=22kV<=60kVA;Multi Ph TR Pole<=22kV>60kVA<=600kVA;Multi Ph TR Pole<=22kV>600kVA;Multi Ph
Distribution Substations Augmentations – Ground Mounted	TR Grd<22kV<=60kVA;One Ph TR Grd<22kV>60kVA<=600kVA;One Ph TR Grd<22kV>600kVA;One Ph TR Grd<22kV<=60kVA;Multi Ph TR Grd<22kV>60kVA<=600kVA;Multi Ph TR Grd<22kV>600kVA;Multi Ph
Distribution Substations Augmentations – Indoor	TR Kiosk<=22kV<=60kVA;One Ph TR Kiosk<=22kV>60kVA<=600kVA;One Ph TR Kiosk<=22kV>600kVA;One Ph TR Kiosk<=22kV<=60kVA;Multi Ph TR Kiosk<=22kV>60kVA<=600kVA;Multi Ph TR Kiosk<=22kV>600kVA;Multi Ph

For Table 2.3.3.1 Descriptor Metrics

3) The project close date is used to determine if a project is closed or open. If project is closed in this financial year then this is the final year in which expenditure is incurred for the project.

4) The quantity of materials booked over the life of the project are used to calculate the units installed.

5) Each project is assessed to determine whether the augmentation is an upgrade of an existing asset or an addition to the network. This is based on reviewing available documentations (Project Scope Statements, Planning Approval Reports, Feasibility Study, Engineering Specifications, Total Outturn Cost Approval or Construction Drawings) of each project. These documents contain details that allow the determination of the nature of the augmentation.

6) There are a small number of projects where documentations are not readily available and keywords within the project description are used to determine the nature of the work. The keywords used are listed in **Error! Reference source not found.**.

7) The results of the extensive review of project documents will be used to expand and refine the accuracy of keywords search in future RIN submissions.

Table 7.5: Keywords used to categorise units added

HV Feeders	LV Feeders	Distribution Transformers
Addition	Addition	Addition
• Est • Establish • New • Tie • Install • Build • Extend • Rel	• Rel • Ins • Ext • Instx • Inssp • Install • Est • New • Build	• Rel • Ins • Ext • Instx • Inssp • Install • VI • Est • New • Build

For Table 2.3.3.2 Cost Metrics

8) The cumulative nominal expenditure are calculated for each project. Filters are applied to identify distribution expenses for projects with accumulated costs greater than or equal to the thresholds defined by the AER. The cost thresholds are $500k for HV feeder projects, $50k for LV feeder projects and no thresholds for distribution transformer projects.

9) Based on the expenditure on materials for each project, the costs are allocated to the augmentation capex categories in Table 7.4. Labour costs are apportioned across the augmentation capex categories using the same proportions as the expenditure on materials.

10) The total direct expenditure is then reported against each category.

7.4 Estimated Information

7.4.1 Justification for Estimated Information

Not applicable.

7.4.2 Basis for Estimated Information

Not applicable.

7.5 Explanatory notes

Not applicable.

8. BoP 2.3.4 - Augex – Total expenditure

The AER requires Energex to provide the following information relating to RIN table 2.3.4 - AUGEX DATA - TOTAL EXPENDITURE:

- **Subtransmission substations, switching stations, zone substations**
- **Subtransmission lines**
- **HV feeders**
- **HV feeders – land Purchase and easements**
- **Distribution Substations**
- **Distribution Substation – land purchase and easements**
- **LV Feeders**
- **LV Feeder – land purchase and easements**
- **Other Assets**

These variables are a part of Regulatory Template 2.3 – Augex.

8.1 Consistency with CA RIN Requirements

Table 8.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes are reported.
Energex must not include information for gifted assets.	No gifted assets are included.
Energex must not include augmentation information relating to connections in this Regulatory Template. Augmentations in relation to connections are to be inputted in the connections Regulatory Template (Regulatory Template 2.5).	No connection expenditure is included and it is stated in the Connections Regulatory Template.
Record all expenditure data on an 'as incurred' basis in nominal dollars.	Expenditure is nominal as incurred.
Energex must explain how the sum of the asset group augmentation expenditures reconciles to the augmentation expenditure in Tables 2.3.1 to 2.3.5	Refer to section 8.5 Explanatory Notes
Expenditure inputted under the 'Land and	'Land and easements' rows are mutually

Requirements (instructions and definitions)	Consistency with requirements
easements' rows are mutually exclusive from expenditure that appear in the rows for the corresponding asset group. For example, Augex attributed to HV feeders must not include expenditure related to 'HV feeders – land purchases and easements'.	exclusive.

8.2 Sources

Table 8.2 sets out the sources from which Energex obtained the required information.

Table 8.2: Information sources

Variable	Source
All variables	DMA RIN

8.3 Methodology

All figures for RIN table 2.3.4 were calculated based on the financial transactions recorded in the financial year. The transactions were filtered to obtain only augmentation related activities.

The population of RIN table 2.3.4 was completed by grouping the expenditure into the required project types as per the table.

8.3.1 Assumptions

Energex applied the following criteria to obtain the required information:

1) Expenditure not relating to materials are apportioned across the augmentation capex categories based on the expenditure on materials for each project.

2) Certain types of equipment that cannot be associated with a specific voltage are classified as Other Assets.

3) Strategic land and easement purchases for subtransmission lines and subtransmission substations, switching stations, zone substations categories are included as Other Assets in RIN table 2.3.4.

8.3.2 Approach

Project List Development

1) A report is run from DMA RIN which listed all projects with transactions within the 2015/16 regulatory year under the following Augex financial activity codes in Table 8.3:

Table 8.3: Augex Financial Activity Codes for Projects Transactions in 2014/15

Activity Code	Description
C2020	Augmentation – Sub Transmission & 11kV Network
C2030	Reliability Improvement & Power Quality
C2050	Demand Primary Reliability Secondary
C2060	Augmentation – 11kV Network
C2070	Land & Right of Way
C2075	Easements
C2090	Engineering and Admin
C2095	Infrastructure Projects
C2099	Transmission PoW Efficiency
C2530	External Business Income
C2565	Augmentation – Distribution
C2566	Power Quality
C2580	Control & Metering
C2585	Load Control
C2590	Engineering and Admin
C2595	Infrastructure Projects
C2599	Distribution PoW Efficiency

2) This report includes all Energex augmentation type projects with financial transactions in FY2015/16. Gifted assets and connection assets are not included in the financial activity codes above.

3) The financial transactions are then filtered to exclude any overheads applied to give the direct expenditure for each project.

Project Data Allocation

1) Each material expense is classified by a Stock Item Group Class (SIGC) which is mapped to a REPEX asset category and classified under its corresponding AUGEX group. This is listed under Table 8.4.

Table 8.4: Grouping of asset categories for RIN table 2.3.4

Augmentation Capex Category	REPEX asset category
Subtransmission Substations, Switching Stations, Zone Substations	SCADA Local Network Wiring Assets SCADA Master Station Assets SCADA AFLC TR Grd>=22kV<=33kV<=15MVA TR Grd>=22kV<=33kV>15MVA<=40MVA TR Grd>=22kV<=33kV>40MVA TR Grd>33kV<=66kV<=15MVA TR Grd>33kV<=66kV>15MVA<=40MVA TR Grd>33kV<=66kV>40MVA TR Grd>66kV<=132kV<=100MVA TR Grd>66kV<=132kV>100MVA TR Grd>132kV<=100MVA TR Grd>132kV>100MVA TR Other Other Instrument Transformer Other NER Switchgear<=11kV;CB Switchgear>11kV<=22kV;CB Switchgear>22kV<=33kV;Switch Switchgear>22kV<=33kV;CB Switchgear>33kV<=66kV;Switch Switchgear>33kV<=66kV;CB Switchgear>66kV<=132kV;Switch Switchgear>66kV<=132kV;CB Switchgear>132kV;Switch Switchgear>132kV;CB Switchgear Other Other OHEW Other Planned Batteries Non REPEX Category - Earthing Transformer Non REPEX Category >= 110kV Capacitor Non REPEX Category >= 110kV CT Non REPEX Category >= 110kV VT Non REPEX Category >11kV <= 33kV Capacitor Non REPEX Category >11kV <= 33kV VT Non REPEX Category >11kV <=33kV CT Non REPEX Category >1kV <= 11kV Capacitor

Augmentation Capex Category	REPEX asset category
Subtransmission Lines	Pole>22kV<=66kV;Wood Pole>66kV<=132kV;Wood Pole>132 kV;Wood Pole>22kV<=66kV;Concrete Pole>66kV<=132kV;Concrete Pole>132kV;Concrete Pole>66kV<=132kV;Steel Pole>132kV;Steel Pole Top>22kV<=66kV Pole Top>66kV<=132kV Pole Top>132kV OH Conductor>22kV<=66kV OH Conductor>66kV<=132kV OH Conductor>132kV UG Cable>22kV<=33kV UG Cable>33kV<=66kV UG Cable>66kV<=132kV UG Cable>132kV Services>22kV<=33kV;C&I Services>22kV<=33kV;Subdivision Services>33kV<=66kV;C&I Services>33kV<=66kV;Subdivision Services>66kV<=132kV;C&I Services>66kV<=132kV;Subdivision Services>132kV;C&I Services>132kV;Subdivision Other Insulators
HV Feeders	Pole>1kV<=11kV;Wood Pole?11kV<=22kV;Wood Pole>1kV<=11kV;Concrete Pole?11kV<=22kV;Concrete Pole>1kV<=11kV;Steel Pole?11kV<=22kV;Steel Pole Top>1kV<=11kV Pole Top>11kV<=22kV OH Conductor>1kV<=11kV OH Conductor?11kV<=22kV;SWER OH Conductor?11kV<=22kV;Single-Phase OH Conductor?11kV<=22kV;Multiple-Phase UG Cable>1kV<=11kV UG Cable>11kV<=22kV Services<=11kV;C&I;Simple Type Services<=11kV;C&I;Complex Type Services<=11kV;Subdivision;Complex Type Services>11kV<=22kV;C&I Services>11kV<=22kV;Subdivision Switchgear<=11kV;Fuse Switchgear<=11kV;Switch Switchgear>11kV<=22kV;Switch Non REPEX Category >1kV <=11kV Regulator

Augmentation Capex Category	REPEX asset category
Distribution Substations	TR Pole<=22kV<=60kVA;One Ph Other TR Pole>22kV<=60kVA;One Ph Other TR Pole>22kV>60kVA<=600kVA;One Ph Other TR Pole>22kV>600kVA;One Ph Other TR Pole>22kV<=60kVA;Multi Ph Other TR Pole>22kV>60kVA<=600kVA;Multi P Other TR Pole>22kV>600kVA;Multi Ph TR Pole<=22kV>60kVA<=600kVA;One Ph TR Pole<=22kV>600kVA;One Ph TR Pole<=22kV<=60kVA;Multi Ph TR Pole<=22kV>60kVA<=600kVA;Multi Ph TR Pole<=22kV>600kVA;Multi Ph TR Kiosk<=22kV<=60kVA;One Ph TR Kiosk<=22kV>60kVA<=600kVA;One Ph TR Kiosk<=22kV>600kVA;One Ph TR Kiosk<=22kV<=60kVA;Multi Ph TR Kiosk<=22kV>60kVA<=600kVA;Multi Ph TR Kiosk<=22kV>600kVA;Multi Ph TR Grd<22kV<=60kVA;One Ph TR Grd<22kV>60kVA<=600kVA;One Ph TR Grd<22kV>600kVA;One Ph TR Grd<22kV<=60kVA;Multi Ph TR Grd<22kV>60kVA<=600kVA;Multi Ph TR Grd<22kV>600kVA;Multi Ph
LV Feeders	Pole<=1kV;Wood Pole<=1kV;Concrete Pole<=1kV;Steel Pole Top<=1kV OH Conductor<=1kV UG Cable<=1kV Services<=11kV;Residential;Simple Type Services<=11kV;Residential;Complex Type

Augmentation Capex Category	REPEX asset category
Other Assets	Public Lighting Luminaires; Major Road Public Lighting Luminaires; Minor Road Public Lighting Lamps; Minor Road Public Lighting Poles/Columns; Major Road Public Lighting Poles/Columns; Minor Road PUBLIC LIGHTING OTHER POLE OTHER Public Lighting Brackets; Major Road Public Lighting Brackets; Minor Road Public Lighting Lamps; Major Road SCADA Field Devices SCADA Communications Network Assets SCADA Communications Site Infrastructure SCADA Communications Linear Assets Pole Top Other SCADA Other OH Conductor Other UG Cable Other Other Meter1 Other Meter2 Services Other Other Other Material

2) Based on the expenditure on materials for each project, the costs are allocated to the augmentation capex categories in Table 8.4. Labour costs are apportioned across the augmentation capex categories using the same proportions as the expenditure on materials. Land and easements expenditure are excluded from the apportionment.

3) Expenditure on land and easements are reported separately under the HV feeders – land Purchase and easements, Distribution substation – land purchase and easements and LV Feeders – land purchase and easements categories accordingly. There were no land and easements transactions in relation to HV feeders, LV feeders or Distribution substations identified in 2015/16.

Other Assets

4) In addition to the grouping of asset categories as described on Table 8.4 above, the following costs are also reported under this category.

- Land and easements expenditure for Subtransmission lines and Subtransmission substations, switching stations, zone substations are reported under Other Assets. The total amount of land and easements expenditure included in 2015/16 for Augex is $1,017,951.34.

- Adjustments due to under or over allocations of labour, fleet oncosts and materials oncosts are also reported under Other Assets. This reflects adjustments to actual costs, posted as an accrual at a high level only. Detailed entries are posted to projects in the following financial year. These amounts represent adjustments to the standard labour rates or oncost rates posted to projects throughout the year based on expected spend, with the adjustment reflecting the actual costs incurred. The total amount of adjustments included in 2015/16 for Augex is $2,891,577.72.

- Expenditure that cannot be associated with any augmentation capex categories are reported under Other Assets. These include projects that are in a very early stage where the scope is still in development, or cancelled projects that do not have a project scope. The total amount of uncategorised expenditure included in 2015/16 for Augex is $229,360.11.

8.4 Estimated Information

8.4.1 Justification for Estimated Information

Not applicable.

8.4.2 Basis for Estimated Information

Not applicable.

8.5 Explanatory notes

Energex is required to explain how the sum of the asset group expenditure reconciles with data in RIN tables 2.3.1 to 2.3.5. The AER gave further guidance through the CA RIN Issues Register:

> *The explanation should include a general description of the link between Tables 2.3.1 to 2.3.3 and Table 2.3.4, including any assumptions and calculations utilised in the relationships between Tables 2.3.1 to 2.3.3 and Table 2.3.4. Tables 2.3.1 and 2.3.2 require expenditure (and other) data on a project close basis. While Ergon is not required to provide this data on an as incurred basis in the tables, it may choose to do so in demonstrating reconciliation if it finds this convenient/ efficient.*
>
> *We would expect expenditure information reported in Table 2.3.3 to reconcile with the corresponding line items in Table 2.3.4. Where this is not the case, Ergon must provide reasons.*

- The HV feeder, LV feeder and distribution substation elements in RIN table 2.3.4 reconciles with RIN table 2.3.3. This is expected as they are based on the same data set.
- RIN table 2.3.4 is unable to be reconciled with RIN table 2.3.1 and Table 2.3.2. The difference are:
  - Expenditure in RIN table 2.3.1 and 2.3.2 are given in real $ 2015/16.
  - RIN table 2.3.1 and 2.3.2 only included closed projects, where RIN table 2.3.4 included open and closed projects.

9. BoP 2.5.1 - Connections

The AER requires Energex to provide the following information in RIN table 2.5.1 – Connections Descriptor Metrics:

- **Residential Connections**
  - **Distribution Metrics**
  - **Augmentation Metrics**
- **Commercial/Industrial Connections**
  - **Distribution Metrics**
  - **Augmentation Metrics**
- **Subdivision Connections**
  - **Underground and Overhead Connections**
  - **Distribution Metrics**
  - **Augmentation Metrics**
  - **Cost per Lot**
- **Embedded Generation Connections**
  - **Underground and Overhead Connections**
  - **Distribution Metrics**
  - **Augmentation Metrics**

The AER requires Energex to provide the following information in RIN table 2.5.2 – Connections Cost Metrics (Expenditure and Volume metrics):

- **Residential Connections**
  - **Simple connections expenditure only**
  - **Complex connections expenditure and volumes**
- **Commercial/Industrial Connections**
  - **Simple connections expenditure only**
  - **Complex connections expenditure and volumes**
- **Subdivision Connections**
  - **Simple connections expenditure and volumes**
  - **Complex connections expenditure and volumes**
- **Embedded Generation Connections**
  - **Simple connections expenditure and volumes**
  - **Complex connections expenditure and volumes**

Actual Information was provided for all figures.

These variables are a part of Regulatory Template 2.5 – Connections.

Please Note: remaining information relating to Regulatory Template 2.5 is covered by the Basis of Preparation 2.5.2

9.1 Consistency with CA RIN Requirements

Table 9.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 9.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for connection services reconciles to internal planning models used in generating Energex's proposed revenue requirements.	As advised by the AER in the CA RIN Issues Register (item 74), this requirement does not apply to DNSPs that are not completing reset RINs
Energex is not required to distinguish expenditure for connection services between standard or ACS in Regulatory Template 2.5.	No distinction was made between SCS and ACS.
Energex is not required to distinguish expenditure for connection services as either capex or opex in Regulatory Template 2.5.	No distinction was made between opex and capex.
Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	No cash contributions were included in these tables
Energex must report data for non-contestable, regulated connection services. This includes work performed by third parties on behalf of Energex.	Only data for regulated services was reported.
Energex must not report data in relation to gifted assets, negotiated connection services or connection services which have been classified as contestable by the AER.	No contestable data was reported and no gifted assets were included.
For augmentation metrics, 'km added' refers to the net addition of circuit line length resulting from the augmentation work of complex connections.	Km added takes into account the effect of multiple circuits.
The definitions of *complex connections* in appendix F provide guidance on the types of augmentation works which must be reported as *connection services*, as descriptor metrics for Table 2.5.1 and as cost metrics for Table 2.5.2.	Complex connections were reported in line with the AER's definitions.
Energex must only report augmentation for connections in Regulatory Template 2.5 relating to customer connection requests, as per the definition of connection expenditure in appendix F. Energex must not double count augmentation requirements by twice reporting augmentation data in Regulatory Templates 2.3 and 2.5.	Connection data has not been duplicated across the Regulatory Templates 2.3 and 2.5.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the MVA added for distribution substations installed for connection services. Where MVA added must be calculated by Energex as the sum of the nameplate rating of all the distribution substations installed for the relevant year.	MVA was calculated as the sum of the nameplate ratings.

9.2 Sources

Table 9.2 sets out the sources from which Energex obtained the required information.

Table 9.2: Information sources

Variable	Source
Table 2.5.1 – Descriptor Metrics	
Residential	
Distribution Substation Metrics	DMA Solution
Augmentation Metrics	DMA Solution
Commercial/Industrial	
Distribution Substation Metrics	DMA Solution
Augmentation Metrics	DMA Solution
Subdivision	
Underground and Overhead Connections	Report Explorer ELL00197 -number of lots commissioned
Distribution Substation Metrics	DMA Solution
Augmentation Metrics	DMA Solution
Cost per Lot	Calculated field (Total cost / no. of lots)
Embedded Generation	
Underground and Overhead Connections	PEACE, Network Connection Contracts
Distribution Substation Metrics	NA
Augmentation Metrics	DMA Solution
Table 2.5.2 – Cost Metrics	
Residential	
Simple Connection LV	DMA Solution

Variable	Source
Complex Connection LV	DMA Solution
Complex Connection HV	DMA Solution
Commercial/Industrial	
Simple Connection LV	DMA Solution
Complex Connection HV (Customer Connected At LV, Minor HV Works)	DMA Solution
Complex Connection HV (Customer Connected At LV, Upstream Asset Works)	DMA Solution
Complex Connection HV (Customer Connected At HV)	DMA Solution
Complex Connection Sub-Transmission	DMA Solution
Subdivision	
Complex Connection LV	DMA Solution
Complex Connection HV (No Upstream Asset Works)	DMA Solution
Complex Connection HV (With Upstream Asset Works)	DMA Solution
Embedded Generation	
Simple Connection LV	PEACE, Network Connection Contracts
Complex Connection HV (Small Capacity)	Not applicable
Complex Connection HV (Large Capacity)	Not applicable

9.3 Methodology

All values covered by this Basis of Preparation were developed using the project listings for the 2015/16 regulatory year. Based on materials booked to projects, project financial activities or project descriptions, these projects were classified into their respective categories required in RIN tables 2.5.1 and 2.5.2, and the required expenditure and quantities have then been reported.

9.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

General

- HV was defined as anything over 1 kV and LV is defined as anything equal or less than 1 kV.

All Residential Variables

- Residential connections were assumed to be equivalent to the Energex financial activity code “C2510 – Domestic and Rural Customer Requested Works” less any projects where the project number begins with ‘S’ (this is considered a subdivision project). Residential variables also include an apportionment of activity code “C2570 – OH Service Connections” based on the ratio of volumes of simple LV connections to total Residential and Commercial and Industrial connections.
- Any project with a transaction against the Energex expense element “6270 – Capital Contributions Non-cash” was excluded based on the AER’s instructions to exclude gifted assets.
- For the volume of connections, it is assumed that each top project represents one connection.

All Commercial/Industrial Variables

- Commercial and Industrial connections were assumed to be equivalent to the Energex financial activity code “C2550 – Commercial and Industrial Customer Requested Work” less any projects where the project number that begins with ‘S’ (this is considered a subdivision project). Commercial/Industrial variables also include an apportionment of activity code “C2570 – OH Service Connections” based on the ratio of simple LV connection volumes to total Residential and Commercial and Industrial connections.
- Commercial and Industrial also includes any projects with a C20 or a C35 activity code. Any projects with a customer requested activity, i.e. C2596 or C2096, are removed as per the reset RIN definition.
- Any project with a transaction against the Energex expense element “6270 – Capital Contributions Non-cash” was excluded based on the AER’s instructions to exclude gifted assets.
- For the volume of connections, it is assumed that each top project represents one connection.

All Subdivision Variables

- Subdivision connections were assumed to be any project that has a project number beginning with ‘S’.
- Any project with a transaction against the Energex expense element “6270 – Capital Contributions Non-cash” was excluded based on the AER’s instructions to exclude gifted assets.
- For the volume of connections, a query was run from Ellipse to extract the lots commissioned for each project. The percentage of lots for each category was obtained from the subdivision agreements register and applied to the total figure reported in template 2.5.1.

- Complex connection HV (upstream works) were assumed to be HV connection projects with Energex expenditure greater than $250k. The assumption is based on the definition of Complex subdivision connection high voltage (with upstream asset works). The definition states that the connection may contain:
- extension or augmentation of HV feeders including major upstream works; and is intended to capture the cost of developing the network to serve new estates and possible upstream shared asset alterations that may be required.
- As “major upstream works” were not defined in the RIN a financial value for Energex expenditure of $250K was used to distinguish these projects.

Embedded Generation

- Connection expenditure for large embedded generation projects were excluded as these assets were either gifted, or don’t involve any works. Connection volumes were included.
- Connections expenditure for PV connections is excluded as it is included in Regulatory Template 4.2 (metering). Connection volumes were included.

9.3.2 Approach

Energex applied the following approach to obtain the required information:

- All individual projects undertaken by Energex within the 2015/16 regulatory year were extracted using the DMA Solution from the source table – GL transaction. This report detailed all projects along with the following items:
  - Project description
  - Financial activity code
  - Expenditure
- The DMA solution identified material transactions broken down by stock codes which were used to categorise projects into the individual connection classifications. These material transactions were also used to calculate the MVA added and net circuit kilometres added.
- A number of projects were excluded from the project list to ensure only projects consistent with the connections definition specified by the AER were reported. Table 9.3 provides the details of the project types excluded:

Table 9.3: Projects Excluded from Connections calculations

Exclusions	Reason
Public Lighting	Street lighting projects were not to be included within the connections Regulatory Template.

Exclusions	Reason
Projects with gifted assets	Gifted assets were excluded in accordance with the CA RIN by removing projects with any transaction in expense code 6270 (Capital Contributions Non-Cash Expenses).
Relocation of connection assets	Any projects that were deemed to be relocating connection assets were excluded as they were alterations to the network rather than connections. This included beautification projects. (i.e. C2596, C2096)

RIN table 2.5.1 – Descriptor Metrics

- Once the project list was defined, each project was assigned to be either a distribution substation, augmentation HV or augmentation LV classification by analysing the stock codes charged to each project. The following logic was applied:
  - A project was deemed to be a distribution substation project if a transformer was transacted against that project in 2015/16.
  - A project was deemed to be a HV or LV project based on the highest proportion of cable (based on expenditure) booked to the project (where a transformer was not booked to the project). If a project had a higher quantity HV cable then it would be classified as a HV project and vice versa. If there was no material to indicate voltage, then the project was assumed to be HV.

Residential

- Distribution Substation Installed Metrics:
  - Residential connections with distribution substations were determined to be those projects with an activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code did not start with ‘S’ and distribution transformers were transacted against the project. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the stock item description and quantity and then summating each figure to give the total.
  - The number of distribution substations was calculated as the frequency of projects that were classified as distribution substation.
  - The total spend figure was calculated as the cost incurred for each project in the 2015/16 regulatory year, for projects where there was a transformer transaction
- Augmentation HV Metrics:

- Residential connections with HV augmentation were determined to be those projects with an activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’. The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
- The total spend figure was calculated as the total project cost for the 2015/16 regulatory year, where there was not a transformer transaction and there was more HV cable than LV cable transacted against the project.

- Augmentation LV Metrics:
  - Residential connections with LV augmentation were determined to be those projects with an activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’ Added to this was also an apportionment of projects with the activity code “C2570 – Service Connections”. The projects under C2570 were allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes for the 2015/16 regulatory year.
  - The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  - The total spend figure was calculated as the total project cost for the 2015/16 regulatory year for projects under C2510, where there was not a transformer transaction and there was more LV cable than HV cable transacted against the project, as well as the apportionment of project cost to the residential classification from C2570.

Commercial/Industrial

- Distribution Substation Installed Metrics:
  - Commercial/Industrial connections with distribution substations were determined to be those projects with an activity code “C2550 – Commercial and Industrial Customer Requested Works” where the project code does not start with ‘S’, or has a funding type of C20 or C35 that had distribution substations transacted against the project. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the item description and quantity and then each figure was summated to give the total MVA.
  - The number of distribution substations was calculated as the frequency of projects that were classified as distribution substation.

- The total spend figure was calculated as the total project cost for the 2015/16regulatory year, for projects where there was a transformer transaction

- Augmentation HV Metrics:
  - Commercial/Industrial connections with HV augmentation were determined to be those projects with an activity "C2550 – Commercial and Industrial Customer Requested Works" where the project code does not start with 'S' or has a funding type of C20 or C35 that had a majority of HV cable transacted against the project. The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  - The total spend figure was calculated as the total project cost for 2015/16 regulatory year, where there was not a transformer transaction and there was more HV cable than LV cable transacted against the project.

- Augmentation LV Metrics:
  - Commercial/Industrial connections with LV augmentation were determined to be those projects with an activity code "C2550 – Commercial and Industrial Customer Requested Works" where the project code does not start with 'S' or a funding type of C20 that had a majority of LV cable transacted against the project. Added to this was also an apportionment of projects with the activity code "C2570 – Service Connections". The projects under C2570 were allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes in the 2015/16 regulatory year.
  - The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  - The total spend figure was calculated as the total project cost for the 2015/16 regulatory year for projects under C2550 where there was not a transformer transaction and there was more LV cable than HV cable transacted against the project as well as the apportionment of project cost to the residential classification from C2570.

Subdivision

- Underground and Overhead Connections
  - To obtain the split between overhead and underground lots gifted to Energex in a financial year, Energex reviewed the lots contracted for the financial periods required. This allowed Energex to identify the number of lots contracted that were underground and the number that were overhead. It applied this ratio to the number of lots gifted to Energex in the financial period.

- Distribution Substation Installed Metrics
  - Subdivision connections with distribution substations were determined to be those projects with a project code beginning with ‘S’ that had distribution substations transacted against the project. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the item description and quantity and then each figure was summated to give the total MVA.
  - The number of distribution substations was calculated as the frequency of projects that were classified as distribution substation.
  - The total spend figure was calculated as the total project cost for the 2015/16 regulatory year, for projects where there was a transformer transaction
- Augmentation HV Metrics
  - Subdivision connections with HV Augmentation were determined to be those projects with a project code beginning with ‘S’ that had the majority of HV cable transacted against the project. The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  - The total spend figure was calculated as the total project cost for the 2015/16 regulatory year, where there was not a transformer transaction and there was more HV cable than LV cable transacted against the project, also where there was a payment made towards the development (i.e. future use conduits, network augmentation)
- Augmentation LV Metrics
  - Subdivision connections with LV Augmentation were determined to be those projects with a project code beginning with ‘S’. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the item description and quantity and then each figure was summated to give the total MVA.
  - The total spend figure was calculated as the total project cost for the 2015/16 regulatory year, where there was not a transformer transaction and there was more LV cable than HV cable transacted against the project
- Cost per Lot
  - To obtain the cost per lot, Energex used the total cost reported in RIN table 2.5.1 for subdivisions divided by the number connections reported in overhead and underground connections for Subdivisions for the year.

Embedded Generation

- Underground and Overhead Connections

- Small solar PV system connections (<30 kW) were extracted from the PEACE customer Information System through report FRC213.
- The split of connections into the underground and overhead categories was done using the connection type found in the FRC213 report. Where connections did not have a connection type the residual connections were allocated to underground and overhead based on the proportions of known connection types.
- The number of large connections (>30 kW) were determined by reviewing network connection contracts.
- The total number of connections reported was the sum of connections >30kW and <30kW.
- No augmentation costs or volumes were allocated to embedded generation. The main costs of solar PV relate to metering works to enable to connection. Metering costs relating to solar PV were included in Regulatory Template 4.2.

RIN table 2.5.2 – Cost Metrics and Volumes

Once the project list was defined the variables required with RIN table 2.5.2 were calculated as follows:

Residential

- Simple Connection LV (expenditure only)
  - All expenditure for projects under the activity code “C2570 – Service Connections” was extracted. The total expenditure figure was then allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes for the 2015/16 regulatory year.
- Complex Connection LV
  - Residential complex connections were defined as being those projects under the activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’. The split between LV and HV was made using an analysis of stock codes transacted against each project. LV was defined as any project that did not include a transformer and had cable installed that was less than or equal to 1kV. Where a project included both LV and HV cables the project was allocated based on the cable type with the highest volume
  - The expense values were calculated as the total project expenses in the 2015/16 regulatory year. The volumes of connections were calculated by using the frequency of projects in the 2015/16 regulatory year.
- Complex Connection HV
  - Complex connection HV was defined as those projects under activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’ and that included a transformer, or more HV cable

than LV cable transacted against the project. For projects in activity C2510 where there were no materials to indicate voltage, these projects were assumed to be HV.

  - The expense values were calculated as the total project expenses in the 2015/16 regulatory year. The volumes of connections were calculated by using the frequency of projects in the 2015/16 regulatory year.

- Volumes
  - The sum total of underground and overhead connections from Table 2.5.1 are allocated across the 3 categories of Simple Connection LV, Complex Connection LV and Complex Connection HV. Volumes are determined by the project counts in the 2 Complex categories as described above. The balance of the total volumes is then allocated to Simple LV.

Commercial/Industrial

- Simple Connection LV (expenditure only)
  - All expenditure for projects under the activity code “C2570 – Service Connections” was extracted. The total expenditure figure was then allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes in the 2015/16 regulatory year. Added to this was expenditure for selected projects under the activity code “C2550 – Commercial and Industrial Customer Requested Works” where the project code does not start with ‘S’. These projects were identified as being LV projects by analysis of the project description.
- Complex Connection HV (Customer Connected At LV, Minor HV Works)
  - This classification was determined to be the remainder of projects under the activity code “C2550 – Commercial and Industrial Customer Requested Works” where the project code d not start with ‘S’.
  - The expense values were calculated as the total project expenses for the 2015/16 regulatory year. The volumes of connections were calculated by using the frequency of projects for the year.
- Complex Connection HV (Customer Connected At LV, Upstream Asset Works)
  - This classification was determined to be the remainder of projects under the C20 or C35 funding type.
  - The expense values were calculated as the total project expenses in the 2015/16 regulatory year. The volumes of connections were calculated by using the frequency of projects for the 2015/16 regulatory year.
- Complex Connection HV (Customer Connected At HV)
  - This classification was determined to be projects under the C20 or C35 funding type that were identified as HV projects. The projects were identified as being HV by having an understanding of the project. This was obtained by asking staff which were their projects where the Customer Connected at HV).

- The expense values were calculated as the total project expenses in the 2015/16 regulatory year. The volumes of connections were calculated by using the frequency of projects in the 2015/16 regulatory year.

- Complex Connection Sub-Transmission
  - This classification was determined to be projects under the C20 funding type that were identified as sub-transmission projects. The projects were identified as being sub-transmission by analysis of the project description, and by asking staff which were their projects were sub-transmission projects.
  - The expense values were calculated as the total project expenses in the 2015/16 regulatory year. The volumes of connections were calculated by using the frequency of projects for the 2015/16 regulatory year.

- Volumes
  - The sum total of underground and overhead connections from Table 2.5.1 are allocated across the 5 categories of Simple Connection LV, Complex Connection HV (customer LV, minor HV works), Complex Connection HV (customer LV, upstream asset works), Complex Connection HV (customer HV) and Complex Connection sub-transmission. Volumes are determined by the project counts in the 4 Complex categories as described above. The balance of the total volumes is then allocated to Simple LV.

Subdivision

- Complex Connection LV
  - This classification was determined to be projects with a project number starting with 'S'. The split between LV and HV was made using an analysis of stock codes transacted against each project. LV was defined as any project that did not include a transformer and had cable installed that was less than or equal to 1kV. Where a project included both LV and HV cables the project was allocated based on the cable type with the highest expense value.

- Complex Connection HV (No Upstream Works)
  - This classification was determined to be projects with a project number starting with 'S' and that included a transformer, high voltage cable (>1kV) or both. For projects that start with an 'S' where there were no materials to indicate voltage, these projects were assumed to be HV.

- Complex Connection HV (Upstream Works)
  - This classification was determined to be projects with a project number starting with 'S' where the expense was greater than $250,000.

- Volumes
  - The sum total of underground and overhead connections from Table 2.5.1 is allocated across the 3 categories of Complex Connection LV, Complex Connection HV (No upstream asset works) and Complex Connection HV (with

upstream asset works). Volumes are determined by the project counts in subdivisions as described above. The balance of the total volumes is then allocated to Complex Connection HV (No upstream asset works).

Embedded Generation

- Simple Connection LV
  - No expenditure data was supplied in this category as per assumptions stated above.
  - Volume data was based on Small solar PV system connections (<30 kW) plus volumes extracted from network connection contracts.
- Complex Connection HV (Small Capacity)
  - No expenditure data was supplied in this category, as per assumptions.
  - Volume data was based on network connection contracts.
- Complex Connection HV (Large Capacity)
  - No expenditure data was supplied in this category, as per assumptions.
  - Volume data was based on network connection contracts.

9.4 Estimated Information

There is no estimated information for this template.

9.4.1 Justification for Estimated Information

Not applicable.

9.4.2 Basis for Estimated Information

Not applicable.

9.5 Explanatory notes

10. BoP 2.5.2 - UG, OH and Simple Connections

The AER requires Energex to provide the following information relating to Connection Descriptor Metrics:

- **Underground Connections (Residential, Commercial/Industrial & Embedded Generation)**
- **Overhead Connections (Residential, Commercial/Industrial & Embedded Generation)**
- **Mean days to connect a residential customer with LV single phase connection**
- **Volume of GSL breaches for residential customers**
- **Volume of customer complaints relating to connection services**

The AER requires Energex to provide the following information relating to Cost Metrics by Connection Classification:

- **Simple Connection LV (Residential and Embedded Generation)**

Actual Information was provided for volume of connections, complaints and GSLs.

These variables are a part of worksheet 2.5– Connections

10.1 Consistency with CA RIN Requirements

Table 10.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 10.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide information within the relevant reportable year for the volumes of connections for residential, commercial and industrial customers	Energex provides information within the relevant reportable year for the volumes of connections for residential, commercial and industrial customers sourced from EPM data
GSL payments made to residential customers	GSLs are payable to small NMI class customers only therefore data provided has been based on the assumption that a small NMI classification is that of a residential customer.

Requirements (instructions and definitions)	Consistency with requirements
Volume of complaints relating to connection services	Volumes of complaints are providing based upon upon categorisation in Energex CMS that relate to connection services
Connection means a physical link between a distribution system and a retail customers premises to allow the flow of electricity.	Connections volumes are either new connections or alterations of existing connections of a physical nature between the distribution network and the customer's premises
Simple connection low voltage is defined as a single/multiphase customer service connection.	Simple connection low voltage follow the definition of single or multiphase customer service connections
Complaint is defined as a written or verbal expression of dissatisfaction about an action, or failure to act, or in respect of a product or service offered or provided by an electricity network distributor.	Complaints recorded in the Energex Customer Management System follow this definition as per the Customer Service Standards.

10.2 Sources

Table 10.2 sets out the sources from which Energex obtained the required information.

Table 10.2: Information sources

Variable	Source
Connections, Embedded Generation Volumes & Mean Days to Connect residential customer with LV single phase connection	EPM Report CUS016 sourced from PEACE
Complaints	Cherwell
GSL Breaches & GSL Payments	Cherwell

10.3 Methodology

- Data provided in tables 2.5.1 and 2.5.2 is derived from EPM Report CUS016 which extracts the data from the PEACE CIS system. This report provides a variety of metrics for each service order that is received, including variables such market outcome status, connection and customer type.

- By cross referencing completed jobs with connection and customer types, data was able to be provided for the Residential, Commercial and Embedded Generation volumes.

- Additionally the report provides the time in days between the obligation start date and time when it is completed in the field. An average of this data was used to provide the mean days to connect residential customers.

- Complaint data is derived from a feedback report which extracts information from the Cherwell system and encompasses all complaints received to Energex (via phone, letter or email). The report details the date the complaint was received and is categorised by the Customer Relations team using the systems feedback structure.

- Guaranteed Service Level (GSL) data is derived from a report which extracts information from the Cherwell system. The report details the type of GSL, the amount paid to a customer and the relevant date the payment was made.

10.3.1 Assumptions

- Data provided includes New Connections, Connection Alterations and Basic Embedded Generation Connection as defined by the National Electricity Rules.

- New connection service orders include both permanent and temporary connections thereby making it possible for more than one new connection service to occur for the same premises (NMI) within the reportable period.

- Mean days to connect may be artificially inflated where obligation timeframes have been renegotiated with a customer in line with the Electricity Industry Code. In these circumstances the earliest work start date is not updated to reflect new timeframes thereby inflating the average days to connect despite obligation timeframes having been changed and connections completed within required timeframes.

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

10.3.2 Approach

Energex applied the following approach to obtain the required information:

Connections

1) Total volumes of connections to the network are established by summing the total volume of connection service orders where the market outcome status was "complete" for the financial year.

2) As connection data is based upon business to business (B2B) information, the connection type taken from FRC213 is used to determine the total number of underground and overhead connections. Where a connection type was not able to

be attained these reflect instances where a retailer has not supplied this information within the B2B. Where there was insufficient data Energex has adopted an apportionment approach. That is, of the total connections where a connection type was supplied, the percentage of these connection types within the relevant year was applied to the instances where insufficient connection type information was available. This approach has been used as it represents a fair and valid calculation for those occasions where a connection type cannot be identified.

3) When using the above approach, the percentage of each unknown connection type (Residential, Commercial & Industrial and Embedded Generation) was less than 4 percent of the total connections which is considered immaterial and therefore reported as actual information.

Mean Days to Connect

Mean days to connect residential customer with LV single phase connection has been determined by calculating the average days between the earliest work start date and the actual completion date (field worker completes work in field) for a connection associated with the same NMI.

Complaints

1) Exclusion of complaints not categorised as the following:
   a. New connection
   b. Existing connection
2) Total volumes of complaints relating to connections are established by summing the total volume of the above complaint categories for the financial year.

GSLs

1) Collation of quarterly reports for financial year
2) Cross checked with a yearly report
3) Exclusions of GSLs not categorised as the following
   a. New Connection
4) Total volumes of GSL breaches are established by summing the total volume of the New Connection GSLs paid for each financial year.
5) GSL payments are established by summing the total financial amount of New Connection GSLs paid for each financial year.

10.4 Estimated Information

No Estimated Information was reported.

10.4.1 Justification for Estimated Information

Not applicable.

10.4.2 Basis for Estimated Information

Not applicable.

10.5 Explanatory notes

Not applicable.

11. BoP 2.6.1 - Non-Network IT & Communications

The AER requires Energex to provide the following information in RIN tables 2.6.1 and 2.6.2 relating to Non-Network Expenditure and annual descriptor metrics for 2015/16:

- **Client Devices Opex and Capex**
- **Recurrent Opex and Capex**
- **Non-Recurrent Opex and Capex**
- **Employee Numbers, users numbers and number of devices**

Actual Information was provided for all variables.

This document provides information regarding Energex total expenditure on IT and Communications (i.e. includes SPARQ costs which are charged to Energex as operating costs)

These variables are a part of Regulatory Template 2.6 – Non-Network Expenditure.

11.1 Consistency with CA RIN Requirements

Table 11.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER

Table 11.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If expenditure is directly attributable to an expenditure category in this Regulatory Template 2.6 it is a Direct Cost for the purposes of this Regulatory Template. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.	Energex has reported figures excluding overheads.
The AER defines Non-network IT & Communication - user numbers as Active IT system log in accounts used for standard control services work scaled for standard control services use (i.e. an account used 50% of the time for standard control services work equals 0.5 active IT log in accounts)	Information reported in table 2.6.2 is in line with this definition.
The AER defines Non-network It & Communications – device numbers as the number of client devices used to provide standard control services scaled for standard	Information reported in table 2.6.2 is in line with this definition.

Requirements (instructions and definitions)	Consistency with requirements
control services use (i.e. a device used 50% of the time for standard control services work equals 0.5 devices). Client Devices are hardware devices that accesses services made available by a server and may include desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones.	
The AER defines Non-network IT & Communications - Non Recurrent Expenditure as IT & Communications - Non Recurrent is all IT & Communications Expenditure that is Non-recurrent Expenditure excluding any expenditure reported under IT & Communications Expenditure - Client Devices Expenditure.	Information reported in RIN table 2.6.1 is in line with this definition.
Non-network IT & Communications Expenditure is all non-network expenditure directly attributable to IT and communications assets including replacement, installation, operation, maintenance, licensing, and leasing costs but excluding all costs associated with SCADA and Network Control Expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices. IT & Communications Expenditure includes: • costs associated with SCADA and Network Control that exist at the Corporate office side of gateway devices (routers, bridges etc.). For example, this would include cost associated with SCADA master systems/control room and directly related equipment • IT & Communications Expenditure related to management, dispatching and coordination, etc. of network work crews (e.g. phones, radios etc.). • any common costs shared between the SCADA and Network Control Expenditure and IT & Communications Expenditure categories with no dominant driver related to either of these expenditure categories. For example, a dedicated communications link used for both corporate office communications and network data communications with no dominant driver for incurring the expenditure attributable to either expenditure category should be reported as IT & Communications Expenditure. • expenditure related to network metering recording and storage at non network sites (i.e. corporate	Information reported in RIN table 2.6.1 is in line with this definition.

Requirements (instructions and definitions)	Consistency with requirements
offices/sites) • Sub categories of Non-network IT& Communications Expenditure are: • Client Devices Expenditure • Recurrent Expenditure (excluding any client devices expenditure) Non-Recurrent Expenditure (excluding any client devices expenditure).	
The AER defines Non-network IT & Communications Expenditure - Client Devices Expenditure as expenditure related to a hardware device that accesses services made available by a server. Client Devices Expenditure includes hardware involved in providing desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones.	Information reported in RIN table 2.6.1 is in line with this definition.
The AER defines Non-network IT & Communications Expenditure - Recurrent Expenditure as all IT & Communications Expenditure that is Recurrent Expenditure excluding any expenditure reported as IT & Communications Expenditure - Client Devices Expenditure.	Information reported in RIN table 2.6.1 is in line with this definition.
The AER defines Non-network IT & Communications Expenditure – Descriptor Metric – employee numbers as the average number of employees engaged in standard control services work over the year scaled for time spent on standard control services work (i.e. an employee spending 50% of their time on standard control services work equating to 0.5ASLs for the purposes of the labour metrics would be 0.5 employees). This metric does not include labour engaged under labour hire agreements.	Information reported in table 2.6.2 is in line with this definition.

11.2 Sources

The following sources were used by SPARQ Solutions to extract information for Energex:

- The financial data provided in RIN table 2.6.1 was extracted from monthly billing invoices provided to Energex by SPARQ Solutions in relation to ICT services rendered as recorded in the SPARQ Solutions finance system.
- Non-financial data provided in RIN table 2.6.2 was sourced as follows:

– Employee numbers – Energex Monthly Performance Report for June 2016 adjusted to reflect SCS employees based on the approved Cost Allocation Methodology (CAM) Non Network allocation methodology.

– User numbers – Microsoft Active Directory reports adjusted for SCS employees in line with the CAM methodology.

– Number of devices – the data reported was sourced from reports used for demonstrating compliance to Microsoft for the licensing obligations associated with the Microsoft applications used by these devices. These counts were determined using System Centre Configuration Manager (SCCM) and Microsoft Active Directory reports adjusted for SCS employees in line with the CAM methodology.

– SCCM is a Microsoft product used for systems management which has the ability to auto discover devices on the network and determine what software is running installed.

– Active Directory is a Directory Service product produced by Microsoft and used by SPARQ Solutions to manage network user accounts and computer objects. All employees were given a user account within Active Directory. Underpinning the directory service is a database which contains unique identifiers for each object as well as various attributes associate with those objects. Reports were run against this database to determine the number of employees, active computers etc.

- The following sources were used in the generation of the ICT figures:
  - EPM – FIN032 Divisional Profit and Loss
  - Ellipse – “Accounting Entry Report – incl Proj & WO Desc (ECA90W)”
  - Regulatory Accounts
  - SPARQ Solutions information as per RIN – Financial System Ellipse

Table 11.2 below sets out the sources from which Energex obtained the required information.

Table 11.2: Information sources

Variable	Source
Client Device Expenditure – OPEX ($000’s)	SPARQ Solutions information based on invoices issued to Energex
Client Device Expenditure – CAPEX ($000’s)	Accounting Entry Report per Ellipse
Recurrent Expenditure – OPEX ($000s)	Profit and Loss for SPARQ Solutions division from EPM for Cost of Sales, Telecommunications, Asset Usage Fee, Contractors and Consultant and Telco and passthrough costs and SLA
Recurrent Expenditure – CAPEX	Capex expenditure per Regulatory accounts less Client

Variable	Source
($000s)	Devices per Accounting Entry Report
Non-Recurrent Expenditure – OPEX ($000s)	Profit and Loss MOPEX RC 1020, account 4940 for 15/16
Non-Recurrent Expenditure – CAPEX ($000s)	Not applicable
Employee numbers	Sourced from Energex Monthly Performance Report for June 2016 adjusted by the CAM set percentage for SCS employees
User numbers	SPARQ Solutions Information provided for Active IT system log in account used in the year adjusted for SCS employees in line with the CAM set percentage
Number of devices	SPARQ Solutions Information provided for Client devices used as provided IT services adjusted for SCS employees in line with the CAM set percentage

11.3 Methodology

- The ICT figures for the CA RIN were developed by Energex with the assistance of SPARQ Solutions, the Energex ICT provider. SPARQ Solutions was created as its own entity to be the joint ICT provider for both Energex and Ergon in 2008/09. The employees for SPARQ Solutions came from the original ICT functions within Energex and Ergon.

- The cost information provided in RIN table 2.6.1 is as sourced from the SPARQ Solutions financial system and is stated “as billed” to Energex. The treatment of these costs as operating or capital expenditure is determined by Energex using its Cost Allocation Model.

- Costs billed by SPARQ Solutions were not allocated to specific Energex business operations as this is dealt with internally by Energex using the Cost Allocation Model. In providing the sub-category financial data, SPARQ Solutions applied the definitions provided by the AER on the following basis:
  - Non recurrent expenditure comprises costs incurred for Energex projects which may be reported as either operating or capital costs in Energex (this allocation was determined by Energex).
  - Client device expenditure reflects costs of supporting the operation and use of the Energex end user device fleet, including service desk support.
  - Recurrent expenditure comprises all other IT & communications costs incurred with SPARQ Solutions by Energex. Following recent clarification of changes in treatment provided by Energex of Network ICT costs, this sub-category

includes the cost of supporting the Energex Network Control and Distribution Management Systems.

11.3.1 Assumptions

No assumptions were made.

11.3.2 Approach

Energex applied the following approach to obtain the required information:

<u>OPEX</u>

1) SPARQ Solutions provided financial data detailing the charges from SPARQ Solutions to Energex. EPM reports identified the SPARQ responsibility centre to obtain 2015/16 figures

2) Energex then reconciled the SPARQ Solutions data to profit and loss reports from EPM. The SPARQ Solutions data was reconciled to the following accounts:
   a. 4940 - Sparq Contractor
   b. 4945 - Contr- Sparq Asset Usage Fee

3) Any variances were investigated and identified to ensure the SPARQ Solutions information matched the Energex financial records.

4) Client Devices Opex – SPARQ Solutions has populated the Opex component on behalf of Energex based on their invoices issued to Energex for client devices.

5) Recurrent Opex – Calculated as the total of the Cost of Sales, Telecommunications Costs, Asset Usage Fee Contractors and Consultant and Telco and passthrough costs and SLA from Energex EPM reports. The "Cost of Sales" expenditure relates to the purchase for small ICT equipment. The telecommunications costs relates to reclass of telecommunication costs for Metering Dynamics and some small item CAPEX purchases sent through the SLA. These figures were reconciled to the SPARQ Solutions RIN information.

6) Inventory is capitalised in Energex accounts and as such it was excluded from the recurrent expenditure charge.

7) Non-recurrent Opex, as per the definition, is deemed to be the Energex MOPEX payments. MOPEX costs were Energex project related costs which were expensed in the Energex Profit and Loss. These costs relate to project scoping and development costs which in accordance with Energex Finance Policy cannot be capitalised. MOPEX costs were costed to one separate Responsibility centre and were sourced from the relevant EPM report for that RC (1020).

CAPEX

1) Client devices Capex – Client devices capex was identified from the Accounting Entry Report for 2015/16, as extracted from Ellipse.

2) Recurrent Capex – Recurrent CAPEX is calculated as the difference between total Energex ICT Capex as recorded in the Regulatory accounts less the client devices calculated above.

3) Non-recurrent Capex – in accordance with the RIN definitions there is no non-recurrent ICT Capex for Energex

Descriptor Metrics

1) Employee Numbers – The employee numbers were extracted directly from the Energex Monthly Performance Report for June 2016. They have been scaled to reflect SCS employees as per the approved CAM Non Network allocation methodology.

2) User Numbers – The number of users was extracted at a point in time from SPARQ Solutions Information and represents as the number of active IT system log-in accounts used during each year. They have been scaled to reflect SCS employees per the CAM methodology. The number of active IT system log-in accounts is made up of the following:
   - Standard users including FTEs, Contractors accounts
   - Generic, test and other accounts required to operate or run the systems
   - FFA Users accounts
   - Field Workers accounts
   - Accounts for Users on extended leave (Maternity leave)
   - External users accounts e.g. Consultants
   - 50% of SPARQ users accounts (Assumed Energex portion)

3) Number of Devices – The number of devices was extracted as the number of client devices used as provided by SPARQ Solutions. They have been scaled to reflect SCS employees as per the CAM methodology.

11.4 Estimated Information

Energex has not used estimated data in preparation of these figures.

11.4.1 Justification for Estimated Information

Not applicable.

11.4.2 Basis for Estimated Information

Not applicable.

11.5 Explanatory notes

Not applicable.

11.6 Accounting policies

The Accounting Policies adopted by Energex during the 2015/16 regulatory year have not materially changed in nature

12. BoP 2.6.2- Non-Network Fleet, Tools and Equipment

The AER requires Energex to provide the following information relating to RIN table 2.6.1 Non-Network Expenditure:

- **Motor Vehicles – Opex and Capex**
- **Other Non-Network Expenditure: Fleet, Tools & Equipment, – Opex and Capex**

The AER requires Energex to provide the following variables relating to RIN table 2.6.3 Non-Network Expenditure:

- **Motor Vehicles Descriptor Metrics**

Actual Information was provided for all figures.

These variables are a part of Regulatory Template 2.6 Non-Network.

12.1 Consistency with CA RIN Requirements

Table 12.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 12.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If expenditure is directly attributable to an expenditure category in this regulatory template 2.6 it is a Direct Cost for the purposes of this regulatory template 2.6. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.	All Direct Costs have been reported as required. Any instances of multiple reporting of expenditure have been identified in accordance with paragraph 2.3 and recorded as a balancing item.
In RIN table 2.6.1, in relation to the Non-network Other expenditure category, if Energex has incurred $1 million or more (nominal) in capital expenditure for a given type or class of assets (e.g. mobile cranes), Energex must insert a row in the regulatory template and report that item separately.	Energex has nominated, and reported separately, expenditure for the following Service Sub-categories and Asset Categories: • Other – Other Fleet: Mobile Generators – Other: Tools & Equipment – Other Non-Network Expenditure Fleet

Requirements (instructions and definitions)	Consistency with requirements
The AER defines a Car as Motor Vehicles other than those that comply with the definition of Light commercial vehicle, Heavy commercial vehicle, Elevated work platform (LCV) or Elevated work platform (HCV).	This definition has been applied.
The AER defines Light commercial vehicles (LCVs) as Motor Vehicles that are registered for use on public roads excluding elevated work platforms that: • are rigid trucks or load carrying vans or utilities having a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; or have cab-chassis construction, and a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; or are buses with a gross vehicle mass not exceeding 4.5 tonnes.	This definition has been applied.
The AER defines Heavy commercial vehicles (HCVs) as Motor Vehicles that are registered for use on public roads excluding Elevated Work Platform (HCV)s that: • have a gross vehicle mass greater than 4.5 tonnes; or are articulated Vehicles; or are buses with a gross vehicle mass exceeding 4.5 tonnes	This definition has been applied.
The AER defines Elevated work platforms (HCV) as Motor Vehicles that have permanently attached elevating work platforms that would be HCVs but for the exclusion of elevated work platforms from the definition of HCV.	This definition has been applied.
The AER defines Elevated work platforms (LCV) as Motor Vehicles that have permanently attached elevating work platforms that are not Elevated work platform (HCV).	This definition has been applied.
The AER defines Non-Network Other Expenditure as all expenditure directly attributable to the replacement, installation, maintenance and operation of Non-network assets, excluding Motor Vehicle assets, Building and Property assets and IT and Communications assets and includes: • non road registered motor vehicles; non road motor vehicles (e.g. forklifts, boats etc.); • mobile plant and equipment; tools; trailers (road	This definition has been applied.

Requirements (instructions and definitions)	Consistency with requirements
registered or not); and elevating work platforms not permanently mounted on motor vehicles; and mobile generators.	

12.2 Sources

Table 12.2 sets out the sources from which Energex obtained the required information.

Table 12.2: Information sources

Variable	Source
Non-Network Opex Expenditure Motor Vehicles & Other 2015/16	• Ellipse Financial Reports: – Profit & Loss Reports – Detailed Transaction Reports • Discussions with Department Managers Operating Expenditure Reports from SG Fleet Australia Pty Limited (Fleet Managers) to allocate cost per Asset Category
Non-Network Capex Expenditure Motor Vehicles & Other 2015/16	• Ellipse Financial Reports: – Capex Summary Reports – Detailed Transaction Reports • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) Previous Annual Performance RIN Capex reports provided by Energex External Reporting team
Non-Network Descriptor Metrics Motor Vehicles 2015/16	• Ellipse Financial Reports: – Detailed Transaction Reports for Capex Purchases • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) Average kms per vehicle category & Units held at end of year data provided by SG Fleet Australia Pty Limited

12.3 Methodology

The below approach was taken to report the Non-Network Motor Vehicle and Other Expenditure into the Categories as outlined in the CA RIN.

12.3.1 Assumptions

Actual financial and fleet data was used to populate relevant metrics.

12.3.2 Approach

Energex applied the following approach to obtain the required information for Non-Network Motor Vehicles & Other Opex Expenditure for 2015/16:

1) Obtained the Profit and Loss report for all Departments within Motor Vehicles, Tools and Equipment and the detailed transaction report for Generator Services, Plant Workshops, Equipment Testing and Laboratory Services from Business Performance & Reporting (Energex Finance team).

2) Discussed reports and transactions with Department Managers for Generator Services, Plant Workshops, Equipment Testing and Laboratory Services to determine their nature, i.e. Tools & Equipment Testing vs Plant Testing.

3) Obtained the annual expenditure report from SG Fleet (Energex Fleet Management Company) by Asset Category by Expense type e.g. Repairs, Maintenance, Fuel & Registration. This information was used as the basis for the asset category split using the data in the Profit and Loss reports. Any additional costs that could not be attributed to an individual asset category were allocated across the asset categories using spend.

4) Specific spend that could be allocated to individual asset categories is detailed as follows:

   a. Generator Services Department operate and maintain Energex mobile generator fleet. Costs associated with Energex Un-Regulated Mobile generator fleet are excluded. Costs were allocated 100% to Non-Network Other.

   b. Plant Workshops Department repair, test and maintain Energex's plant e.g. Heavy Commercial Vehicles (HCV) with Elevated Work Platforms, HCV Crane Borers & HCV with Cranes. Work orders were used to determine costs relating to HCV – EWP and Heavy Commercial. Where there was insufficient detail the costs were allocated based on the known HCV - EWP and Heavy Commercial costs. This translated to approximately an 74/26 split.

   c. The Laboratory Services Department test and maintain the Energex meter assets as well as some of Energex's Tools and Equipment. The costs for this department were split using detailed transaction reports based on an analysis of work orders.

   d. The Equipment Testing Department electrically test and maintain Energex's tool and equipment assets as well as electrically test Heavy Commercial Vehicles (HCV) with Elevated Work Platforms. The costs for this department were split between Motor Vehicles and tools & equipment using detailed transaction reports based on an analysis of work orders.

e. Fringe Benefits Tax (FBT) was allocated 100% to Network Expenditure Car, as all other Motor Vehicle and Other Assets are excluded from FBT.

f. Employee Contributions were allocated 100% to Non-Network Operating Expenditure Car. Some employment positions within Energex require the employee to have a vehicle. This vehicle is also available for the employee's private use. For this privilege, the employee pays a contribution to Energex to offset the value of this private use, via salary sacrifice. (Contributions are deducted from operating expenditure)

5) In all instances, depreciation was excluded from the reported opex costs.

6) In all instances, only indirect costs were reported.

Energex applied the following approach to obtain the required information for Non-Network Motor Vehicles & Other Capex Expenditure for 2015/16:

1) Obtained the Capital Summary report and Detailed Capital Transaction Report for Motor Vehicles, Tools and Equipment from Business Performance & Reporting (Energex finance team). These reports were used to identify the total of the financial purchases in the 2015/16 year.

2) The Detailed Capital Transaction report was used to report the capital purchases, using the unique Fleet Number to identify the applicable asset categories. As a result of a requirement to make progress payments on certain assets due to the length of time that these assets take to build (in order to mitigate some of the suppliers' financial risk), transactions are recorded over several months. Assets that fall into this category were Elevated Work Platforms.

3) Per Clause 10.5 of the CA RIN, Energex has incurred $1 million or more in capital expenditure for one class of assets and this is therefore reported separately. The additional asset class is Tools & Equipment. Mobile Generator expenditure is also reported separately. All other Non-Network Other Capital Expenditure is reported as Other Non-Network Expenditure Fleet.

4) The Complete Fleet list was obtained, including historical Fleet Terminations (sales). This report was used to determine the number of fleet in each category as at 30 June 2016. This report was provided by SG Fleet Australia Pty Limited.

5) The Annual Performance (AP) RIN report was obtained to reconcile Motor Vehicles, Tools and Equipment Capital Expenditure.

Energex applied the following approach to obtain the required information for Non-Network Motor Vehicle Annual Descriptor Metrics 2015/16:

Annual kilometres:

1) Annual kilometres were calculated using the reported kilometres of all active vehicles during the financial year.

2) If the vehicle was purchased or sold during the financial year, the kilometres were annualised and the unit included in the average, as being active for the full year.

3) The vehicles were split into the asset categories and the kilometres totalled. The average was obtained from dividing the total kilometres by the number of vehicles. The raw annualised kilometres and Motor Vehicle data was provided by SG Fleet Australia Pty Limited.

Units Purchased:

1) The units purchased were based on vehicles delivered in 2015-16 FY. This was sourced from the Energex Fleet Program of Work file. This file is managed by the Fleet and Plant Operations team.

2) Vehicles that were paid and delivered to Energex in 2015-16 FY but not commissioned as at 30 June 2016 have been included in the numbers reported.

Leased Units:

1) Energex does not lease any Motor Vehicles.

Number in Fleet:

1) Obtained the Fleet Units on a month by month basis and have averaged over the FY as per appendix F of the CA RIN (Definitions) which outlines that the Number in Fleet should be the average of the units across the financial year. This information was sourced from SG Fleet Australia Pty Limited.

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

1) The percentage was determined by calculating the fleet on-costs allocated to each activity within the Energex Chart of Accounts using the FIN073 Account Balances Report. Every activity was mapped to one of three service classification – Standard Control Service (SCS), Alternative Control Services (ACS) or Unregulated Services.

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

12.4 Estimated Information

No Estimated Information was used. Information provided by Energex's Fleet Management Company SG Fleet Australia has also been relied upon and is considered Actual Information. This information was based on invoice payments per motor vehicle category.

12.4.1 Justification for Estimated Information

Not applicable.

12.4.2 Basis for Estimated Information

Not applicable.

12.5 Explanatory notes

- In must be noted that there can sometimes be a small delay between when an invoice is paid and the asset is commissioned. If either of these circumstances span a financial year, a disconnect between financial transactions and physicals (when the asset is actually commissioned) occurs.
- For 2015-16 an amount of $0.9M in fuel tax credits was received.
- The reduction in Mobile Generators CAPEX spend ($5.4M in 2014/15 to $0.3M in 15/16) is driven by the Mobile Generator replacement program. Twenty (20) units were purchased in 2014/15 compared to zero (0) in 2015/16. The 2015/16 expenditure of $0.3M was driven by enhancements made to the 20 units purchased in 2014/15 to ensure compliance with legislative and operational requirements.

12.6 Accounting policies

The Accounting Policies adopted by Energex during the 2015-16 regulatory year have not materially changed in nature.

13. BoP 2.6.3 - Non-Network Property

The AER requires Energex to provide the following information in RIN table 2.6.1 relating to Non-Network Expenditure for 2015/16:

- **Buildings and Property Opex and Capex**
- **Other Non-Network Expenditure – Plant and Equipment Opex and Capex**
- **Other Non-Network Expenditure – Office Furniture Opex and Capex**

Actual Information was provided for all variables.

These variables are a part of Regulatory Template 2.6 – Non-Network Expenditure.

13.1 Consistency with CA RIN Requirements

Table 13.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 13.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If expenditure is directly attributable to an expenditure category in this Regulatory Template 2.6 it is a Direct Cost for the purposes of this Regulatory Template. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.	Energex has reported all figures inclusive of Direct costs and on-costs but excluding overheads as per the Energex CAM approved by the AER.
In relation to the Non-network Other expenditure category, if Energex has incurred $1 million or more (nominal) in capital expenditure over the last five regulatory years for a given type or class of assets (e.g. mobile cranes), Energex must insert a row in the Regulatory Template and report that item separately.	Energex has stated values for “Other – Plant and Equipment” and “Other – Office Furniture” as their totals are greater than $1 million over the last five regulatory years.
Non-network Buildings and Property Expenditure – Expenditure directly attributable to non-network buildings and property assets including: the replacement, installation, operation and maintenance of non-network buildings, fittings and fixtures. It includes expenditure related to real chattels (e.g. interests in land such as a lease) but excludes expenditure related personal chattels (e.g. furniture) that should be reported under Non-network Other expenditure.	Energex now records furniture separately from fixtures and fittings, thereby enabling their reporting as “Other – Office Furniture” to align to the AER requirements.

13.2 Sources

- EPM – FIN032 Divisional Profit and Loss
- EPM – FIN077 Transaction Report
- Regulatory Accounts

Table 13.2 sets out the sources from which Energex obtained the required information.

Table 13.2: Information sources

Variable	Source
Building & Property Expenditure – OPEX ($0's)	Accounting Entry Report (FIN077) for RC 2510 and all indirect activities
Building & Property Expenditure – CAPEX ($0's)	Regulatory Accounts & FIN077 for C3010 CW Land, C3015 CW Buildings, C3040 Fixtures & Fittings
Other – Office Furniture – CAPEX ($0's)	Regulatory Accounts & FIN077 for C3041 PA Furniture & Office Equipment

13.3 Methodology

13.3.1 Assumptions

No assumptions were made in collating this information.

13.3.2 Approach

Energex applied the following approach to obtain the required information for Non Network Buildings and Property Expenditure (OPEX and CAPEX) and Non Network Other – Office Equipment CAPEX for 2015/16:

OPEX

1) The financial transaction report (FIN077) was run from EPM for the financial year for the responsibility centre 2510 – Property and filtered to all indirect activities (any activities starting with the number 6)

2) Non-regulated activities were identified using the activity code 62010 and excluded from the transaction report.

3) Network related Property costs were identified using the activity code 62025 and excluded from the transaction report.

4) Merger related Property costs were identified using the activity code 62960 and excluded from the transaction report as these are included in another RIN Template.

5) The remaining dollar value was used to report the 15/16 OPEX spend for Non Network Property.

Overheads and depreciation have not been included in the CA RIN as per the AER approved CAM.

CAPEX

1) The total figure reported for Buildings and Property Capex was taken from the stated figures in the regulatory accounts. These figures included direct expenditure and on-costs but excluded general overheads in accordance with Energex AER approved CAM. These figures also include non-system land purchases (C3010 – Constructed Assets – Land) and fixtures and fittings to the buildings (C3040 – Constructed Assets – Fixtures & Fittings).

2) Energex previously recorded furniture as part of fixtures and fittings but is now able to separately capture these costs (C3041 – Purchased Assets – Furniture & Office Equipment). Consequently, in accordance with the AER definition of Buildings and Property, personal chattels (e.g. furniture) expenditure is not included in the stated numbers for Buildings and Property and is reported as Other Non Network Expenditure - Office Furniture

3) When reviewing transactions it was identified that there was approximately $2.5M worth of furniture incorrectly classified as Fixtures & Fittings (C3040 – Constructed Assets – Fixtures & Fittings). This value has been removed from Total Buildings and Property Expenditure and added to the items that were correctly classified as Other Non Network Expenditure - Office Furniture.

13.4 Estimated Information

No Estimated Information has been reported.

13.5 Explanatory notes

Building and Property Capex decreased significantly in the 15/16 FY compared to the 14/15 FY as the 14/15 FY was the construction period of the previous AER determination and the 15/16 FY was the planning stage of the new AER period.

13.6 Accounting policies

The Accounting Policies adopted by Energex have not materially changed in nature.

14. BoP 2.7.1 – Vegetation Management Descriptor Metrics

The AER requires Energex to provide the following information relating to Table 2.7.1 – Descriptor Metrics By Zone:

For Zone 1

- **Route Line Length Within Zone (Km)**
- **Number Of Maintenance Spans (0's)**
- **Total Length Of Maintenance Spans (Km)**
- **Length Of Vegetation Corridors (Km)**
- **Average Number Of Trees Per Maintenance Span (0's)**
- **Average Frequency Of Cutting Cycle (Years)**

Length Of Vegetation Corridors (Km) is Estimated Information. All other information is Actual Information.

These variables are a part of worksheet 2.7 – Vegetation Management.

14.1 Consistency with CA RIN Requirements

Table 14.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 14.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Identify one or more vegetation management zones across the geographical area of Energex's network. To do so consider: a) areas where bushfire mitigation costs are imposed by legislation, regulation or ministerial order; and areas of the network where other recognised drivers affect the costs of performing vegetation management work.	Vegetation management zones have been defined as one area as legislation and cutting profiles are consistent across the Energex area. Energex fits inside one Bioregion
Provide, on separate A4 sheets, maps showing: a) each vegetation management zone; and the total network area with the borders of each vegetation management zone.	The map of the Energex vegetation management zone is contained in Appendix 4 – Vegetation Management Zones Map
For each vegetation management zone identified in 12.1 above, provide in the basis of preparation: a) a list of regulations that impose a material cost on performing vegetation management works (including,	Please refer to section 14.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
but is not limited to, bushfire mitigation regulations); b) a list of self-imposed standards from Energex's vegetation management program which apply to that zone; and an explanation of the cost impact of regulations and self-imposed standards on performing vegetation management work.	
If Energex does not record the average number of trees per maintenance span, estimate this variable using one or a combination of the following data sources… Field surveys using a sample of maintenance spans within each vegetation management zone to assess the number of mature trees within the maintenance corridor. Sampling must provide a reasonable estimate and consider the nature of maintenance spans in urban versus rural environments in determining reasonable sample sizes.	Field surveys were done to determine the variables. Please refer to section 14.3.2 (Approach) for further details.
A vegetation maintenance span is a span in DNSP's network that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include Inspection of vegetation Maintenance Spans	Demonstrated in section 14.3.2 (Approach)
For the purposes of calculating the average number of trees per maintenance span, a tree is a perennial plant (of any species including shrubs) that is: • equal to or greater in height than 3 metres (measured from the ground) in the relevant reporting period; and of a species which could grow to a height such that it may impinge on the vegetation clearance space of power lines.	Energex has counted trees based solely on the AER's definition.

14.2 Sources

Table 14.2 sets out the sources from which Energex obtained the required information.

Table 14.2: Information sources

Variable	Source
Route Line Length Within Zone (Km)	ArcGIS
Number Of Maintenance Spans (0's)	Field Survey ArcGIS

Variable	Source
Total Length Of Maintenance Spans (Km)	Field Survey ArcGIS
Length Of Vegetation Corridors (Km)	ArcGIS Vegetation Contractor Report
Average Number Of Trees Per Maintenance Span (0's)	Field Survey ArcGIS
Average Frequency Of Cutting Cycle (Years)	Contract Invoices

14.3 Methodology

Route line length was able to be extracted from the Energex ArcGIS. Energex has calculated all other variables using a statistical sampling methodology. This was performed for both Urban/CBD and Rural areas and across each of the zones to obtain the CA RIN figures.

14.3.1 Assumptions

A rural area is defined by the level of demand on a network. The following ranges were used to define a rural span:

- Urban/CBD: >300 kVA/km
- Rural: ≤300 kVA/km

The trees counted for the calculation the average number of trees per maintenance span were defined as a perennial plant (of any species including shrubs) that is:

- equal to or greater in height than 3 metres (measured from the ground) in the relevant reporting period; and
- of a species which could grow to a height such that it may impinge on the vegetation clearance space of power lines.

14.3.2 Approach

Definition of Vegetation Management Zones

1) Vegetation management zones have been defined as one area due to legislation and cutting profiles being consistent across the Energex area. Energex vegetation contracts are based around postcode areas which are modified to create suitable work packages. .

2) For the map of each zone with respect to the Energex network area please refer to Appendix 4 – Vegetation Management Zones Map.

Route Line Length within each Zone

1) The route line length has been extracted from ArcGIS as the point to point line length within each zone (not taking into account multiple circuits). The Rural and Urban/CBD proportions were broken up by the demand on each section of the network in each zone.

Number of Maintenance Spans, Average Number of Trees per Maintenance Span and Total Length of Maintenance Spans

A sample of spans was obtained to survey the spans in Energex's network that are subject to active vegetation management practices, for both Urban/CBD and Rural areas:

1) From the population sizes a minimum sample size for each population was calculated using the National Statistical Service's "Sample Size Calculator". The final number of sampled spans (2940 spans for both Urban/CBD and Rural) were deliberately higher than the minimum calculated to ensure statistical relevance of the sampling.

2) Spans were then chosen to be surveyed by repeating the following process until the span sample size for both urban/CBD and rural areas had been exceeded.

3) A pole with ID of nnnn (where $n = 1 \rightarrow \infty$) was taken. The pole with an ID matching the last prime number before nnnn was then chosen and centred in the middle of the GIS screen. The scale of the map was then adjusted to 1:3000 for urban areas and 1:10000 for rural areas and all spans in that area were included in the sample.

4) Each span was then surveyed by Energex. The span was marked as a maintenance span if the span required active vegetation management. If a span was labelled a maintenance span the number of trees that conformed to the AER definition of a tree were counted.

5) The number of urban/CBD and rural maintenance spans was calculated by multiplying the individual proportions of maintenance spans to non-maintenance spans by their respective population sizes.

6) The total length of maintenance spans was then calculated as the number of maintenance spans multiplied by the applicable average length of a span (calculated as the route line length in each zone and feeder category divided by the respective total number of spans obtained from GIS).

7) The sample average number of trees per vegetation maintenance span for urban/CBD and rural areas was used as the average for the entire population

8) For 2015/16 FY the statistical sample from 2014/15 was used on the basis that all 3 statistical sample undertaken have demonstrated no significant variations.

Length of Vegetation Corridors

1) The length of vegetation corridors was determined using 100% of the 132/110kV network and by recording each span that qualifies as a corridor as per the AER definition for voltages 33kV and below. Each month the vegetation contractors would provide a report on the number of spans that they worked on that qualified as a corridor. For each contractor's area the average span length was determined which was then multiplied by the number of spans. These were then summated and used for the figure at Length of vegetation corridor in table 2.7.1. To determine the break up for urban and rural the total % of urban/rural network for Energex was used. For 2015/16 the figure is deemed to be an estimate due to one of Energex's vegetation contractors going into administration and due to relevant staff leaving there was a two month period where no data was provided. For those two months the average of the other ten months has been used.

Average Frequency of Cutting Cycle

1) Average Frequency of Cutting Cycles were determined by contractors invoice. For each postcode it was determined when an invoice was received and the length of time in months which had elapsed since the previous invoice had been received. Each postcodes length was then split into its urban/rural component. It's time elapsed in months was applied to the individual section. The average over all postcodes with an appropriate weighting for its length was then used for the figure in the RIN table.

Legislation and self-imposed standards applicable to Vegetation Management

- Electrical Safety Act 2002
- Electrical Safety (Codes of Practice) Notice 2013
- Electrical Safety Regulation 2013
- Electricity Act 1994
- Electricity Regulation 2006
- Electrical Safety Code of Practice for Working Near Exposed Live Parts
- Mains Asset Maintenance Policy (RED 0296)
- OS119 Vegetation Worker Clearance
- Energex Health and Safety Risk Management (RED 554)

14.4 Estimated Information

The length of vegetation corridors (km) reported figure is Estimated Information. All other information is Actual Information.

We have also had regard to the correspondence issued to management by the Australia Energy Regulator on 21 July 2016 and 12 August 2016 clarifying the presentation requirement of information in the Regulatory Information Notice data templates, in particular the requirement to present information as estimated if the Energex is unable to provide actual Information.

14.4.1 Justification for Estimated Information

For 2015/16 the figure is deemed to be an estimate due to one of Energex’s vegetation contractors going into administration and due to relevant staff leaving there was a two month period where no data was provided.

14.4.2 Basis for Estimated Information

The data reflects actual length for 10 months as reported by the contractors plus the monthly average (of the 10 months) for the two months where the data was not reported.

14.5 Explanatory notes

Actual information would be achieved by 36 data entries (3 contractors’ monthly entries times 12 months). 34 out of 36 of these data entries are actual figures and only 2 are estimated. Energex considers that this is the best estimate given its based on predominantly actual data and the very limited estimated data is based on contemporaneous data for 2015/16.

The field survey method for calculating these variables was used and determined to be the most reliable and timely method available to Energex. Other methods were either not available to Energex (aerial inspection, LiDAR) or did not provide the data granularity required to estimate these variables accurately. For further detail please refer to the methodology section.

15. BoP 2.7.2 - Vegetation Management Cost Metrics

The AER requires Energex to provide the following information relating to RIN Table 2.7.2 – Expenditure Metrics By Zone:

For Zone 1

- **Tree trimming (excluding hazard trees) ($0's)**
- **Hazard tree cutting ($0's)**
- **Ground Clearance ($0's)**
- **Vegetation Corridors Clearance ($0's)**
- **Inspection ($0's)**
- **Audit ($0's)**
- **Contract Liaison Expenditure ($0's)**
- **Tree Replacement Program Costs ($0's)**

The following information is Estimated Information:

- **Ground Clearance ($0's)**
- **Vegetation Corridors Clearance ($0's)**
- **Inspection ($0's)**
- **Audit ($0's)**

All other information is Actual Information.

These variables are a part of Regulatory Template 2.7 – Vegetation Management.

15.1 Consistency with CA RIN Requirements

Table 15.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 15.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Identify one or more vegetation management zones across the geographical area of Energex's network. To do so consider: a) areas where bushfire mitigation costs are imposed by legislation, regulation or ministerial order; and areas of the network where other recognised drivers affect the costs of performing vegetation management work.	Vegetation management zones have been defined as one area as legislation and cutting profiles are consistent across the Energex area. Energex fits inside one Bioregion
Provide, on separate A4 sheets, maps showing: a) each vegetation management zone; and the total network area with the borders of each vegetation	The map of all Energex vegetation management zones is contained in Appendix 4 – Vegetation Management Zones

Requirements (instructions and definitions)	Consistency with requirements
management zone.	Map
For each vegetation management zone identified in 12.1 above, provide in the Basis of Preparation: a) a list of regulations that impose a material cost on performing vegetation management works (including, but is not limited to, bushfire mitigation regulations); b) a list of self-imposed standards from Energex's vegetation management program which apply to that zone; and an explanation of the cost impact of regulations and self-imposed standards on performing vegetation management work.	Please refer to BoP 2.7.1 – Approach.
If hazard tree clearance expenditures are not recorded separately, include these expenditures within tree trimming expenditure and shade the cells for hazard tree clearance black. For the Regulatory Years including and after 2015, Energex must provide data on hazard tree clearance expenditure.	Hazard tree cutting expenditure is captured separately and has been reported in RIN Table 2.7.2
If *ground clearance* works are not recorded separately, include these expenditures within tree trimming expenditure and shade the cells for *ground clearance* black. For the *Regulatory Years* including and after 2015 Energex must provide data on *ground clearance* expenditure.	Ground clearance expenditure is captured separately and has been reported in RIN Table 2.7.2
Only include expenditure on inspections where Energex inspects solely for the purpose of assessing vegetation. Include inspection expenditure for inspections assessing both Energex's assets and vegetation under maintenance (Regulatory Template 2.8). If Energex does not record expenditure on inspections of vegetation separately, Energex may shade the cells black. For the Regulatory Years including and after 2015, Energex must provide data on inspection expenditure.	Inspection is captured separately and has been reported in RIN Table 2.7.2
If auditing of vegetation management work is not recorded separately, include these expenditures within inspection expenditure. If Energex does not record expenditure on audits of vegetation management work separately, Energex may shade the cells black. For the Regulatory Years including and after 2015, Energex must provide data on auditing expenditure.	Audit expenditure is captured separately and has been reported in RIN Table 2.7.2
Annual vegetation management expenditure across all categories and zones must sum up to the total vegetation management expenditure each year. In Table 2.7.2, add any other vegetation management expenditure not requested in any other part of Regulatory Template 2.7 (or added in Regulatory Template 2.8) in	Refer to section 15.5 (Explanatory Notes)

Requirements (instructions and definitions)	Consistency with requirements
total annual vegetation management expenditure. In the Basis of Preparation, explain the expenditures that have been included in this table.	

15.2 Sources

Table 15.2 sets out the sources from which Energex obtained the required information.

Table 15.2: Information sources

Variable	Source
All Variables	EPM FIN077 General Ledger Transactions

15.3 Methodology

NAMP (Network Asset Management Plan) line costs were extracted from EPM and mapped to the RIN categories.

15.3.1 Assumptions

Tree trimming

- these costs were captured under NAMP lines VG02 (11kV - Vegetation Sector Based Distribution) and VG05 (LV - Customer Requested Vegetation).

Hazard tree cutting

- These costs were captured under NAMP lines VG03 (33kV VTA) and VG04 (11kV VTA).

Vegetation Corridor Clearance

- these costs were captured under NAMP line VG01 (Transmission clearance zone maintenance), VG07 (Transmission Vegetation Spots) and VG08 (Transmission Survey). This only captures costs for the 132 kV and 110 kV networks. The corridor clearing costs for 33 kV and below lines have been recorded from monthly reports provided by the vegetation contractor.

Ground Clearance

- these costs were captured under NAMP line VG01 (Transmission clearance zone maintenance), VG07 (Transmission Vegetation Spots) and VG08 (Transmission Survey). This only captures costs for the 132 kV and 110 kV networks. The ground clearing costs for 33 kV and below lines have been recorded from monthly reports provided by the vegetation contractor.

Inspection Costs

- Inspection Costs have been recorded from monthly reports provided by the vegetation contractor.

Audit Costs

- Audit Costs have been recorded from monthly reports provided by the vegetation contractor.

Tree replacement costs

- for the 2015/16 financial year this is captured under standard jobs linked to NAMP line VG06 (Vegetation – Tree Replacement MOU's).

Contractor Liaison Expenditure

- Energex captures these costs as an indirect cost and therefore has not included them in this Regulatory Template.

Other vegetation management costs not specified in sheet

- Energex captures these costs as an indirect cost and therefore has not included them in this Regulatory Template.

- The below costs were incurred against 41500 (Vegetation) for 41500 due to an incorrect Purchase order mapping. These costs are related to Transmission Access Tracks (NAMP line TF16) and should be recognised in the Access Track category of Table 2.8 (and also rolled into the 'Other' category of Table 2.12).This is in addition to the already mapped costs for TF16 incurred correctly on 41200 ($27,912). Excluding 8104-General Overhead the adjustment is $541,405.

NAMP	Element	Expense Element Description	Account Code	Total
TF16	3302	Ordinary Time Proj Cost	465041500P0003302	$0
	4900	Contractors - Operations	465041500P0004900	$541,405
	8102	Fleet On-cost	465041500P0008102	$0
	8104	General Overhead	465041500P0008104	$238,759
TF16 Total				$780,165

15.3.2 Approach

Vegetation management zones have been defined as one area as legislation and cutting profiles are consistent across the Energex area.

For the map of each zone with respect to the Energex network area please refer to Appendix 4 – Vegetation Management Zones Map.

15.4 Estimated Information

Estimated Information was reported for corridor clearance, ground clearance, audit and inspection expenditure.

We have also had regard to the correspondence issued to management by the Australia Energy Regulator on 21 July 2016 and 12 August 2016 clarifying the presentation requirement of information in the Regulatory Information Notice data templates, in particular the requirement to present information as estimated if the Energex is unable to provide actual Information.

15.4.1 Justification for Estimated Information

For 2015/16 the figure is deemed to be an estimate due to one of Energex's vegetation contractors going into administration and due to relevant staff leaving there was a two month period where no data was provided.

15.4.2 Basis for Estimated Information

The data reflects actual costs for 10 months as reported by the contractors plus the monthly average (of the 10 months) for the two months where the data was not reported.

15.5 Explanatory notes

Actual information would be achieved by 36 data entries (3 contractors' monthly entries times 12 months). 34 out of 36 of these data entries are actual figures and only 2 are estimated. Energex considers that this is the best estimate given its based on predominantly actual data and the very limited estimated data is based on contemporaneous data for 2015/16.

The total figures in table 2.7.2 exceed total vegetation expenditure as costs are captured multiple times (e.g. some of vegetation corridor clearance is also included in tree trimming).

16. BoP 2.7.3- Vegetation Management Unplanned Events

The AER requires Energex to provide the following information relating to Table 2.7.3 – Descriptor Metrics Across All Zones - Unplanned Vegetation Events:

- **Number Of Fire Starts Caused By Vegetation Grow-Ins (NSP Responsibility) (0's)**
- **Number Of Fire Starts Caused By Vegetation Blow-Ins And Fall-Ins (NSP Responsibility) (0's)**
- **Number Of Fire Starts Caused By Vegetation Grow-Ins (Other Party Responsibility) (0's)**
- **Number Of Fire Starts Caused By Vegetation Blow-Ins And Fall-Ins (Other Party Responsibility) (0's)**

These variables are a part of worksheet 2.7 – Vegetation Management.

All information is Actual Information.

16.1 Consistency with CA RIN Requirements

Table 16.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 16.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In table 2.7.3, fill out the unplanned vegetation events table once, providing the requested information across Energex's entire network.	The variables supplied are across the entirety of the Energex network for the regulatory year.
Energex is not required to provide information requested in table 2.7.3 for Initial Regulatory Years where it does not currently have it, and may shade the cells black. For Regulatory Years 2015 and thereafter, Energex must provide this information.	Data was available and has been supplied for the regulatory year.

16.2 Sources

Table 16.2 sets out the sources from which Energex obtained the required information.

Table 16.2: Information sources

Variable	Source
No. of fire starts	Focal Point Database

16.3 Methodology

The number of fire starts was determined from service calls logged in the Focal Point system. These outages were then analysed to determine how many fire starts there were in each category.

16.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

Under Queensland legislation Energex is responsible for all vegetation that can affect the electricity network. Consequently there will be zero “other party responsibility” number for all years.

16.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Energex’s Focal Point records incoming calls from the public, fire brigade, police, Energex field staff and emergency services. These incoming calls become Incidents. All Incidents were filtered and extracted from Focal Point to obtain the jobs involving fire.

2) Each fire Incident was then further disseminated to see if vegetation was involved.

3) These Incidents are then filtered manually to identify actual fire starts

16.4 Estimated Information

No Estimated Information was reported.

16.4.1 Justification for Estimated Information

Not applicable.

16.4.2 Basis for Estimated Information

Not applicable.

17. BoP 2.8.1- Maintenance Descriptor Metrics

The AER requires Energex to provide the following information relating to RIN table 2.8.1 – Descriptor Metrics for Routine and Non-Routine Maintenance:

- **Routine and non-routine asset quantities at year end by maintenance activity and asset category as specified by the AER for each regulatory year.**
- **Routine and non-routine asset quantities inspected and maintained by maintenance activity and asset category as specified by the AER for each regulatory year**
- **The average age of assets by maintenance activity and asset category as specified by the AER for each regulatory year**
- **Routine and non-routine inspection and maintenance cycles by maintenance activity and asset category as specified by the AER**

All information is actual information.

This BoP does not relate to:

Maintenance Activity: SCADA and Network Control Maintenance which is covered by BoP 2.8.2

17.1 Consistency with CA RIN Requirements

Table 17.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 17.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
For each of the *maintenance* subcategories prescribed in the template, add rows for additional subcategories if these are material and necessary to disaggregate financial or non-financial data, for example, to disaggregate asset groups according to voltage levels or to specify inspection/ maintenance cycles.	Additional rows have been added.
For each maintenance subcategory, provide in separate columns the data for inspection cycles and maintenance cycles.	Data has been provided in accordance with this requirement.
For the inspection cycle for each maintenance subcategory, express this as 'n' in the statement 'every n years'. For example, if the inspection cycle is 'every 6 years', put '6' in the inspection cycle column.	Data has been provided in accordance with this requirement. Please refer to section 17.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
Similarly, for the maintenance cycle for each maintenance subcategory, express this as ‘n’ in the statement ‘every n years’. For example, if the maintenance cycle is ‘every 3 years’, put ‘3’ in the maintenance cycle column.	
For inspection and maintenance cycles, asset quantity, and average age of the asset group, use the highest-value (i.e. highest replacement cost) asset type in the asset group as the basis.	Data has been provided in accordance with this requirement. Please refer to section 17.3.2 (Approach).
Where there are multiple inspection and maintenance activities, report the cycle that reflects the highest cost activity.	This approach has been used to provide cycle time information. Please refer to section 17.3.2 (Approach).
For ‘Asset Quantity’, provide in separate columns: – The total number of assets (population) at the end of the regulatory year, for each asset category – The number of assets actually inspected or maintained during the regulatory year, for each asset category	Both sets of figures have been provided.

17.2 Sources

Table 17.2 sets out the sources from which Energex obtained the required information.

Table 17.2: Information sources

Variable	Source
Asset quantity – At Year End	DMA
Asset quantity inspected/maintained	DMA
Average age of asset group	DMA
Inspection Cycle	Joint Workings Network Maintenance Framework DMA
Maintenance Cycle	Joint Workings Network Maintenance Framework DMA
Service Cable – Asset quantity – At Year End	MARS OH Service Program Tracking data (Spreadsheet)

17.3 Methodology

17.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

17.3.1.1 Asset Quantities – At Year End

Number of Poles

- Customer Poles were excluded
- All poles are reported excluding streetlight poles

Line Patrolled (Route km)

- Total quantities were reported in Kilometres.
- The conductor data excludes conductors in store or held for spares.
- All lengths stated exclude any vertical components to the conductor, such as sag.
- The length of each conductor category is the total conductor route length and not each individual phase conductor length, noting:
  - 11kV routes predominately consist of 3 conductors.11kV routes also includes some single phase (2 conductors) in its total length.
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral; however lengths provided includes all variations.

Underground Cable Length (Route km)

- Total quantities are reported in Kilometres.
- The cable data does not include cables that are in store or held for spares.
- All lengths stated exclude any vertical components to the cable, such as vertical tails.
- The length of each cable category is the total cable route length and not each individual phase.

17.3.1.2 Asset Quantities – Inspected/Maintained

Asset quantities at year end & Asset quantities inspected/maintained alignment:

- The ‘Asset Quantity at year end’ was extracted from NFM (Network Facilities Management) historical data for the 2015/16 financial year.

- The Asset quantities were based on Asset Classes which are categories coded in NFM against each piece of equipment in the Energex network.
- These Asset classes align with particular types of assets that perform the same function.
- The ‘Asset quantity inspected/maintained’ was derived using NAMP line program codes for financial activities 41100 and 41200, which were mapped to the AER asset maintenance categories.
- A NAMP line can contain work performed against multiple asset classes (from NFM).
- In addition, asset classes (from NFM) can have work performed on them, in multiple NAMP lines.
- In some instances, work performed against certain types of asset classes (from NFM) were costed and counted against a NAMP line which was mapped to a different AER asset maintenance category.
- The method used to calculate the ‘Asset Quantity at year end’ will not always align with the ‘Asset quantities inspected/maintained’ because the asset may have been inspected or maintained against a NAMP line that is mapped to another Maintenance Asset Category.
- The unit of measure used to count ‘Asset quantities inspected/maintained’ is not always aligned with the ‘Asset Quantity at year end’ as there are multiple asset types which are used in counting each NAMP line within an Asset Category i.e. Unit counts are typically ‘number of work orders’ and not ‘length (KM)’ or ‘number of customers’. In addition, ‘Asset quantities inspected/maintained’ can represent multiple visits to an asset if the cycle is less than annual. Hence, there is not always a direct correlation between the number of assets inspected/maintained and the number of assets at year end.

NAMP codes:

- Energex builds its operating program according to Network Asset Management Plan (NAMP) codes. NAMP codes categorise lower level activities into higher level groups of like type work. For example, ‘NAMP - BZ15 (11kV Circuit Breaker Maintenance)’ contains maintenance work over many types of 11kV Circuit Breakers all with different criteria and cyclic frequencies.
- The NAMP codes are used for reporting purposes and have been used by Energex for reporting progress to plan and delivery performance.
- Typically, NAMP codes are categorised by Asset Class or created specifically to measure key focus programs.

Mapping NAMP codes to RIN categories:

- In order to meet the data requirements in worksheet 2.8, Energex's NAMP codes have been mapped to equivalent AER RIN categories in Ellipse (+NA2 table).
- Whilst the NAMP codes are not a one-for-one match with the RIN categories they were reasonably aligned.
- Where a single NAMP code related to multiple RIN categories, the RIN category that aligned the closest to the NAMP code was used. For example, 'NAMP - BZ25 (Oil analysis)' contains predominately oil sampling costs for Power transformers and associated tap changers. The NAMP code does, however, also include some costs for regulators and earth transformers. Therefore this NAMP code was mapped to 'Transformers – Zone Substation', as this type of equipment wore the most volume of work.

Underground cable maintenance:

- Underground cable maintenance was apportioned between CBD and non-CBD based on the actual amount of 11kV underground cable in the CBD area relative to total 11kV cable in the network. Table 17.3 provides the apportionment between CBD and non-CBD underground cable.

Table 17.3: Apportionment between CBD and non-CBD underground cable

Cable Category	Length of cable	Percentage of total
CBD	206 Kilometers	1.14%
Non-CBD	17,838 Kilometers	98.86%

17.3.2 Approach

Energex applied the following approach to obtain the required information:

17.3.2.1 Asset Quantity – At Year End

Pole Tops and Pole Inspection – Number of Poles:

1) A report was extracted from DMA that detailed the poles in the Energex network with the following corresponding information:
    a. The pole material
    b. The original installation year
    c. The number of poles.
2) Poles that have a material type of plastic have been excluded.

3) Poles with a site grade code of W have been excluded as this site grade code indicates that the pole is customer owned.

4) Streetlight Poles have been excluded

5) The pole quantity was calculated as the sum of poles installed up to and including the end of the 2015/16 year.

Service Lines – Number of Customers:

1) The number of service lines for 2015/16 was calculated for worksheet 5.2 – Asset Age Profile. For details of the methodology used please refer to the relevant basis of preparation for that worksheet.

2) The assets for year-end for service lines were calculated by a count of service cable across the MARS database. Replacements and overhead New Connections data was then reviewed against the current data and the data adjusted accordingly.

3) Quantities of assets inspected/maintained for service lines were based on the number of services maintained during the year, as opposed to the number of customers.

Overhead Assets – Line Patrolled (Route km):

1) A report was run from DMA that gave the Energex overhead conductor values broken down by:

   a. Conductor sizing category (Imperial, Metric or Other)

   b. The circuit for each conductor

   c. The Line Length

   All lengths extracted exclude any vertical components to the conductor, such as sag.

2) Excluded from this report were conductors known to be owned by customers. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurs Energex has captured these conductors. In addition, where Energex believes that there is a benefit to continue to store data related to assets that have been sold to customers, the data has not be removed from NFM.

3) To minimise the effect of captured customer conductors, it has been assumed that where a conductor is connected to only customer assets then that conductor is also customer owned.

Table 17.4 – Customer owned Conductor Length

Customer Conductor	2015/16
Length (km 000's)	5.03

4) Lengths have been reported in Kilometres (km)

Underground Cable Length (Route km):

1) A report was run from DMA that gave the Energex underground cables broken down by:
    a. Snapshot point the year
    b. Cables constructed voltage is equal to or less than 22kV or greater than 22kV
    c. The cable length
    d. Feeder Category (CBD or Non-CBD)

    All lengths stated exclude any vertical components to the cable, such as vertical tails.

2) Excluded from this report were cables known to be owned by customers. Cables are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these conductors. . In addition, where Energex believes that there is a benefit to continue to store data related to assets that have been sold to customers, the data has not be removed from NFM.

3) To minimise the effect of captured customer cables, it has been assumed that where a cable is connected to only customer assets then that cable is also customer owned.

Table 17.5 – Customer owned cable

Customer Cable	2015/16
Length (km 000's)	13.91

4) Lengths have been reported in Kilometres (km)

Distribution Substation – Number of Installed Transformers:

1) A report was extracted from DMA detailing the transformers in the Energex network with the following corresponding information:
    a. Location –Distribution
    b. Transformer Type –Distribution
    c. Has Customers - Yes or No
    d. Installation Date

    This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

    This report also excludes all assets indicated as customer owned.

Distribution Substation – Number of Switches:

1) A report was extracted from DMA that contained an extract for the 2015/16 financial year detailing the circuit breakers, reclosers and Ring main Units in the Energex network with the following corresponding information:
    a. Snapshot date
    b. Equipment type
    c. Install date

    This report includes all circuit breakers, reclosers and Ring Main Units that were commissioned at the relevant point in time. RMU's were added in FY15/16.

    This report excludes all assets indicated as customer owned.

Distribution Substation – Other Equipment:

1) The other equipment for distribution substations has been defined as all low voltage circuit breakers.
2) A report was extracted from DMA for the 2015/16 financial year detailing all circuit breakers in the Energex network with the following corresponding information:
    a. Rating of low voltage
    b. Snapshot date
    c. First recorded install date

Distribution Substation – Number of Distribution Substation Properties Maintained:

1) A report was extracted from DMA for the 2015/16 financial year detailing all sites in the Energex network with the following corresponding information:
    a. Snapshot Date
    b. Sites System Unique Number

c. First recorded install date

This report includes all sites that contained a transformer at the relevant point in time and was filtered for distribution transformers only.

This report excludes all assets indicated as customer owned.

Zone Substation – Number of Zone Substation Transformers:

1) A report was extracted from DMA for the 2015/16 financial year detailing the transformers in the Energex network with the following corresponding information:
   a. Location – Zone
   b. Transformer Type – Power
   c. Has Customers - Yes or No
   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excludes all assets indicated as customer owned.

Zone Substation – Number of Distribution Transformers within Zone Substations:

1) A report was extracted from DMA for the 2015/16 financial year detailing the transformers in the Energex network with the following corresponding information:
   a. Location – Zone
   b. Transformer Type –Distribution
   c. Has Customers - Yes
   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time. This report also excludes all assets indicated as customer owned.

Zone Substation – Number of HV Transformers:

1) A report was extracted from DMA for the 2015/16 financial year detailing the transformers in the Energex network with the following corresponding information:
   a. Location – Zone
   b. Transformer Type –Distribution
   c. Has Customers - No
   d. Installation Date

This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

This report also excludes all assets indicated as customer owned.

Zone Substation – Other Equipment:

1) A report was extracted from DMA for the 2015/16 financial year detailing Connectivity Assets and Non Connectivity Assets:
   a. Snapshot Date
   b. Installation Date
   c. Quantity
2) The Assets report excluded all assets that are not In Service or Inferred In Service, as these assets were not currently in use at the relevant point in time.
3) Only assets within a Zone or Bulk supply substation have been included in either report. These reports also exclude all assets indicated as customer owned. Items that are excluded either exist in other Maintenance categories or are not part of the maintenance program. Asset report also excluded the following assets:
   a. Transformers
   b. Tee Off
   c. Cable Boxes
   d. Internal Circuit Transformers
   e. Cable Joints
   f. Fault Indicators
   g. Switch Fuses
   h. Fuse Units
   i. Poles and Towers
   j. Earthing
   k. Cross Arms
   l. Metering
   m. Communication and SCADA

   Only assets within a Zone or Bulk supply substation have been included in either report. These reports also exclude all assets indicated as customer owned.
4) The reports were combined to establish total Zone Substation – Other Equipment volumes.

Zone Substation – Number of Zone Substation Properties Maintained

1) A report was extracted from DMA for the 2015/16 financial year for Bulk and Zone substations that detailed the number of Zone Substations properties that Energex maintains.

Public Lighting – Number of Public Lights Maintained

1) A report was extracted from DMA for the 2015/16 financial year detailing the streetlights in the Energex network with the following corresponding information:
   a. Snapshot Date
   b. Installation Date
   c. Light Category – Major or Minor

   This report also excludes all asset indicated as customer owned.

2) Reports were combined and had filters applied to the following category
   a. Light Category

Subtransmission Asset Maintenance – For DNSPs with Dual Function Assets

1) Not applicable to Energex as Energex does not have dual function assets.

Number of Distribution Pole Mounted Plant (Transformers, Regulators, Sectionalisers and Reclosers)

1) A report was extracted from NFM for the 2015/16 financial year detailing the distribution pole mounted plant (transformers, regulators, sectionalisers and reclosers) in the Energex network with the following corresponding information:
   a. Snapshot Date
   b. Installation Date
   c. Quantity – Major or Minor

   This report excluded all equipment that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excluded all assets indicated as customer owned.

Zone Substation Inspection – All Zone Substation Assets – Number of Zone Substation Properties Maintained

1) A report was extracted from DMA for the 2015/16 financial year detailing Connectivity Assets and Non Connectivity Assets:
   a. Snapshot Date
   b. Installation Date
   c. Quantity

2) The Assets report excluded all assets that are not In Service or Inferred In Service, as these assets were not currently in use at the relevant point in time.

3) Only assets within a Zone or Bulk supply substation have been included in either report. These reports also exclude all assets indicated as customer owned. Items that are excluded either exist in other Maintenance categories or are not part of the maintenance program. Asset report also excluded the following assets:

   a. Tee Off
   b. Cable Boxes
   c. Internal Circuit Transformers
   d. Cable Joints
   e. Fault Indicators
   f. Switch Fuses
   g. Fuse Units
   h. Poles and Towers
   i. Earthing
   j. Cross Arms
   k. Metering
   l. Communication and SCADA

   Only assets within a Zone or Bulk supply substation have been included in either report. These reports also exclude all assets indicated as customer owned.

4) The reports were combined to establish total Zone Substation – Equipment volumes.

Distribution Asset Inspection – Distribution Substations – Number of Distribution Substation Properties

1) Data reported was the same as stated for "Distribution Substation – Number of Distribution Substation Properties Maintained" above. For the details of the methodology refer to the relevant section above.

All Underground Feeder Assets

1) Data reported was the total underground feeder length. This was the sum of "Underground Cable Length (Route km)" stated above. For the methodology refer to the relevant section above.

17.3.2.2 Asset Quantity Inspected / Maintained

1) DMA report RIN001 was used to identify asset quantities inspected / maintained against each of the maintenance activity / categories.

17.3.2.3 Average Age of Asset Group

Pole Tops and Pole Inspection – Number of Poles:

1) Reports produced for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) were used to determine average age. Please refer to BoP 5.2.1 for aging calculations.

2) The average age of assets in 2015/16 is the average of assets from 1910/11 to 2015/16.

Service Lines – Number of Customers:

1) The number of service lines and their age profile for 2015/16 was calculated for Regulatory Template 5.2 – Asset Age Profile. For details of the methodology used please refer to the relevant BoP for that Regulatory Template 5.2.

2) The average age of service lines was calculated by taking the average age of the assets per Regulatory Template 5.2.

Overhead Assets – Line Patrolled (Route km):

1) Energex produces conductor age based on pole age which is the best data available. Poles were chosen because there is a correlation between poles and conductors and pole data is extremely accurate.

2) Reports produced for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) were used to determine average age. Please refer to BoP 5.2.1 for aging calculations.

3) The average age of assets in 2015/16 is the average of assets from 1910/11 to 2015/16.

Underground Cable Length (Route km):

1) Energex produces cable age based on equipment age which is the best data available. Equipment was chosen because there is a correlation between equipment and cable. Equipment data is extremely accurate.

2) Reports produced for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) were used to determine average age. Please refer to BoP 5.2.1 for aging calculations.

3) The average age of assets in 2015/16 is the average of assets from 1910/11 to 2015/16.

Distribution Substation – Number of Installed Transformers:

1) Reports produced for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) were used to determine average age. Please refer to BoP5.2.1 for aging calculations.

2) The average age of assets in 2015/16 is the average of assets from 1910/11 to 2015/16.

Distribution Substation – Number of Switches:

1) A report was extracted from DMA that contained an extract for the end the 2015/16 financial year detailing the circuit breakers and reclosers in the Energex network with the following corresponding information:

    a. Snapshot date

    b. Equipment type

    c. Install date

   This report includes all circuit breakers, reclosers and Ring Main Unit that were commissioned, at the relevant point in time. This report excludes all assets indicated as customer owned. RMU's were added in FY15/16.

2) The average age was then calculated using the installation dates of the assets.

3) All assets with an installation date of 1901 have been ignored in the calculation of average age. This is due to the asset age of 1901 being used when the age cannot be determined for an asset.

Distribution Substation – Other Equipment:

1) The other equipment for distribution substations has been defined as all low voltage circuit breakers.

2) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing all circuit breakers in the Energex network with the following corresponding information:

    a. Rating of low voltage

    b. Snapshot date

    c. First recorded install date

3) Average age was calculated from the first recorded install date.

Distribution Substation – Number of Distribution Substation Properties Maintained:

1) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing all sites in the Energex network with the following corresponding information:

    a. Snapshot Date

b. Sites System Unique Number

c. First recorded install date

This report includes all sites that contained a transformer at the relevant point in time. This report excludes all asset indicated as customer owned.

2) All assets with an installation date of 1901 have been ignored in the calculation of average age.

3) Average age was calculated from the first recorded install date.

Zone Substation – Number of Zone Substation Transformers:

1) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing the transformers in the Energex network with the following corresponding information:

   a. Location – Zone

   b. Transformer Type – Power

   c. Has Customers - Yes or No

   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time. This report also excludes all asset indicated as customer owned.

2) All assets with an installation date of 1901 have been ignored in the calculation of average age.

3) Average age was calculated from the installation date.

Zone Substation – Number of Distribution Transformers Within Zone Substations:

1) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing the transformers in the Energex network with the following corresponding information:

   a. Location – Zone

   b. Transformer Type –Distribution

   c. Has Customers - Yes

   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excludes all asset indicated as customer owned.

2) All assets with an installation date of 1901 have been ignored in the calculation of average age.

3) Average age was calculated from the installation date.

Zone Substation – Number of HV Transformers:

1) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing the transformers in the Energex network with the following corresponding information:
   a. Location – Zone
   b. Transformer Type –Distribution
   c. Has Customers - No
   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excludes all asset indicated as customer owned.

2) All assets with an installation date of 1901 have been ignored in the calculation of average age.

3) Average age was calculated from the installation date.

Zone Substation – Other Equipment:

1) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing Connectivity Assets and Non Connectivity Assets:
   a. Snapshot Date
   b. Installation Date
   c. Quantity

2) The Assets report excluded all assets that are not In Service or Inferred In Service, as these assets were not currently in use at the relevant point in time.

3) Only assets within a Zone or Bulk supply substation have been included in either report. These reports also exclude all assets indicated as customer owned. Items that are excluded either exist in other Maintenance categories or are not part of the maintenance program. Asset report excluded the following assets:
   a. Transformers
   b. Tee Off
   c. Cable Boxes
   d. Circuit Transformers

e. Cable Joints

f. Fault Indicators

g. Switch Fuses

h. Fuse Units

i. Poles and Towers

j. Earthing

k. Cross Arms

l. Metering

m. Communication and SCADA

Only assets within a Zone or Bulk supply substation have been included in either report.

These reports also excluded all assets indicated as customer owned.

4) All assets with an installation date of 1901 have been ignored in the calculation of average age.

5) Average age was calculated from the installation date.

Zone Substation – Number of Zone Substation Properties Maintained:

1) A report was extracted from DMA that contained data for the 2015/16 financial year for Bulk and Zone substations detailing the installation date of Zone Substations properties that Energex maintains based on the first event associated with a power transformer at the site.

2) Average age was calculated from the installation date.

Public Lighting – Number of Public Lights Maintained:

1) Reports produced for RIN table 5.2.1 (Regulatory Template 2.5 – Asset Age Profile) were used to determine average age. Please refer to BoP 5.2.1 for aging calculations.

2) The average age of assets in 2015/16 is the average of assets from 1910/11 to 2015/16.

Subtransmission Asset Maintenance – For DNSPs with Dual Function Assets:

1) Not applicable to Energex as Energex does not have dual function assets.

Number of Distribution Pole Mounted Plant (Transformers, Regulators, Sectionalisers and Reclosers)

1) A report was extracted from DMA that contained data for the 2015/16 financial year detailing the distribution pole mounted plant (transformers, regulators, sectionalisers and reclosers) in the Energex network with the following corresponding information:

   a. Snapshot Date

   b. Installation Date

   c. Quantity – Major or Minor

   This report excluded all equipment that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excluded all asset indicated as customer owned.

2) All assets with an installation date of 1901 were ignored in the calculation of average age.

3) Average age was calculated from the installation date.

Zone Substation Inspection – All Zone Substation Assets – Number of Zone Substation Properties Maintained

1) A report was extracted from DMA that contained data for the end the 2015/16 financial year detailing Connectivity Assets and Non Connectivity Assets:

   a. Snapshot Date

   b. Installation Date

   c. Quantity

2) The Assets report excluded all assets that are not In Service or Inferred In Service, as these assets were not currently in use at the relevant point in time.

3) Only assets within a Zone or Bulk supply substation have been included in either report. These reports also exclude all assets indicated as customer owned. Items that are excluded either exist in other Maintenance categories or are not part of the maintenance program. Asset report excluded the following assets:

   a. Tee Off

   b. Cable Boxes

   c. Circuit Transformers

   d. Cable Joints

   e. Fault Indicators

   f. Switch Fuses

   g. Fuse Units

   h. Poles and Towers

   i. Earthing

j. Cross Arms

k. Metering

l. Communication and SCADA

Only assets within a Zone or Bulk supply substation have been included in either report.

These reports also excluded all assets indicated as customer owned.

Distribution Asset Inspection – Distribution Substations – Number of Distribution Substation Properties

1) Data reported is the same as stated for "Distribution Substation – Number of Distribution Substation Properties Maintained" above. For the details of the methodology refer to the relevant section above.

All Underground Feeder Assets

1) Reports produced for RIN table 5.2.1 (Regulatory Template 2.5 – Asset Age Profile) were used to determine average age. Please refer to BoP 5.2.1 for aging calculations.

2) The average age of assets in 2015/16 is the average of assets from 1910/11 to 2015/16.

17.3.2.4 Inspection and Maintenance Cycles

1) The cyclic frequencies that Energex have reported are based on the current Joint Workings Maintenance Activity Frequency (MAF) document.

2) The DMA report RIN001 was used to identify cycle frequencies against each of the maintenance activity / categories on the following basis:

   a. NAMP's mapped to Asset Categories recorded in Ellipse (+NA2 Table). Established as data source in DMA Solution from Ellipse.

   b. These Inspection and Maintenance Cycle Times are applied to Maintenance Scheduled Tasks (MST's) against a unique Standard Job in Ellipse. These Standard Jobs align to the MAF and established as a data source in RIN Configuration Solution from Ellipse as a "Data Source".

   c. NAMP's are unique to either an Inspection (41100) or Maintenance (41200) financial activity.

   d. Step 1 - Highest actual expenditure Inspection/Maintenance NAMP selected for each Asset Category using financial data sourced in the DMA Solution from Ellipse.

e. Step 2 - As there could be multiple Standard Jobs per NAMP (with different cycle times), the highest actual Standard Job physical quantities was selected for the highest expenditure Inspection/Maintenance NAMP as per Step 1 (excludes non-cyclic Standard Jobs e.g. reactive) for each applicable Asset Category. Only one inspection/maintenance cycle time per asset category was used to be populated in “Actual” CA RIN template.

17.4 Estimated Information

No Estimated Information was reported.

17.4.1 Justification for Estimated Information

Not applicable.

17.4.2 Basis for Estimated Information

Not applicable.

17.5 Explanatory notes

- In the prior Category Analysis (CA) RIN, submitted in April 2015, Energex added and reported data for the below additional variables in table 2.8.1. Variables added are included in the table below:

Maintenance Activity	Maintenance Asset Category	Unit of Measure – Asset Quantity
Zone Substation Inspection	All Zone Substation Assets	
Distribution Asset Inspection	Distribution Substations	
Distribution Pole Mounted Plant Maintenance	All Distribution PMP (Transformers, Regulators, Sectionalisers and Reclosers)	
Underground Feeder Asset Inspection	All underground Feeder Assets	
Pilot Cable Inspection and Maintenance	All Pilot Cables (Copper & Fibre)	Length (Meters)
Other	Adjustments to labour, fleet and material oncosts	

- Energex has retained these categories for 15/16 CARIN.

- Energex has added a new “Other” Maintenance Activity to separately reflect adjustments to actual costs, posted as an accrual at a high level only. Detailed entries are posted to projects in the following financial year. These amounts represent adjustments to the standard labour rates or oncost rates posted to projects throughout the year based on expected spend, with the adjustment reflecting the actual costs incurred.

18. BoP 2.8.2- Maintenance SCADA and Network Control Maintenance

The AER requires Energex to provide the following variables relating to RIN table 2.8.1 - Descriptor Metrics for Routine and Non-Routine Maintenance:

- **SCADA and Network Control Maintenance**
- **Protection Systems Maintenance**
- **All Pilot Cables (Copper and Fibre)**

This Basis of Preparation is for the development of the following data for the variables stated above:

- **Total Asset volumes**
- **Average Age of Asset**

All information is Actual Information.

These variables are a part of worksheet 2.8 – Maintenance.

This BoP does not relate to:

- **Maintenance Quantities for all other maintenance activity and asset category which are covered by BoP 2.8.1**
- **Routine and non-routine asset quantities inspected and maintained for all maintenance activities and asset categories which are covered by BoP 2.8.1**

Maintenance Cost Metrics which are covered by BoP 2.8.3

18.1 Consistency with CA RIN Requirements

Table 18.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 18.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide corresponding age profile data in Regulatory Template 5.2 as per its respective instructions.	Corresponding age profiles were reported in Regulatory Template 5.2
When Energex must make an estimate because it cannot populate the input cell with actual information, Energex must demonstrate that it has provided the best estimate it can.	Demonstrated in section 18.4 (Estimated Information) below
For 'Asset Quantity', provide in separate columns: (a) the total number of assets (population) at the end of	RIN table 2.8.1 has been completed in accordance with this requirement

the regulatory year, for each asset category the number of assets actually inspected or maintained during the regulatory year, for each asset category	

18.2 Sources

Table 18.2 sets out the sources from which Energex obtained the required information.

Table 18.2: Information sources

Variable	Source
SCADA Network and Control Maintenance (This category was an addition of RTUs, IEDs, Microwave links, DSS Head ends, DSS Radios and Multiplex equipment)	SCADA Base (direct and via DMA) and project documentation, CBMD, ROSS, CNMS
Protection Systems Maintenance	IPS (Via DMA)
All Pilot Cables (fibre and copper)	CBMD

18.3 Methodology

SCADA Network and Control Maintenance:

- Asset quantities for this variable were determined by adding up the total number of the below assets for the 2015/16 financial year using age profile.
  - RTUs;
  - IED;
  - Microwave Links;
  - DSS Head Ends;
  - DSS Radios; and
  - Multiplex equipment
  - MPLS nodes.
- Various techniques were used to create 2015/16 financial year age profile and to correct the data for the financial year. Refer to section 18.4 (Estimated Information) for further details.

Protection System Maintenance:

- Asset quantities for this variable were determined by extracting the total installation base from the IPS system via DMA.

- The average age of assets for these variables were generated using 2015/16 financial year age profile and determining the average age.

Pilot cables

- Asset quantities for this variable were determined by extracting total meters installed per annum from the CBMD database.
- The average age of assets for these variables were generated using 2015/16 financial year age profile and determining the average age.

18.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- In relation to IEDs and DSS Radios, the database only contains initial commissioning information. Subsequent data associated with maintenance swap outs (i.e. replacements) is not captured due low cost of the equipment. As a result, this tends to overstate the age of the IED and DSS Radio fleet; however, this was not considered a significant issue on the basis that IEDs and DSS Radios are typically low cost in nature.

18.3.2 Approach

Energex applied the following approach to obtain the required information for each of the categories stated above:

18.3.2.1 Total Assets per financial year

1) Age profile data was obtained.
2) Total assets were calculated by adding up totals identified in the age profile.

18.3.2.2 Average Age of Asset per financial year

- Using the age profiles generated above, the average age of the asset base was calculated.

18.3.2.3 Asset age profiles

The assumptions and Estimated Information used for creating the age profiles are also reported in other Basis of Preparation documents but are reproduced here for continuity.

- Various different methods were used to obtain the required data, below is an explanation for each of the sub-asset categories. These age profiles were then added up to obtain the asset category age profile:
  - Protection relays – IPS data extracted via DMA was utilised.

- RTUs – a review of SCADA control scheme design documentation was performed identifying when hardware was changed. Results were collated into a spread sheet.
- IEDs – Commissioned records from SCADABase (via DMA) were utilised.
- Microwave links – The CBMD application was queried to determine the commissioning dates for each link.
- DSS Head end, radios and repeaters – The ROSS application database was queried to provide an installed / commissioning date.
- Multiplex – No history information is available in management or finance system for these assets, the total population as at end of 15/16 was estimated and was spread based on when fibre optic cable was installed.
- Total number of commissioned Multi-protocol label switching (MPLS) nodes as based on project documentation.
- Pilot Cables – The CBMD application database was queried to determine commissioning dates for each point to point link, links without a commissioning date were apportioned across the known age profile.

18.4 Estimated Information

All information covered by this BoP chapter is Actual Information.

18.4.1 Justification for Estimated Information

Not applicable.

18.4.2 Basis for Estimated Information

Not applicable.

18.5 Explanatory notes

Below are justifications to claim estimated data as actual data.

18.5.1 Justification for Estimated Information

Energex has significant amount of data about the various assets reported, however does not have historical data for some sub categories of the asset categories and has used various techniques to apportion these. In each case where this been done, the result either does not materially change the resulting data, no valid alternate methods are available or the judgement and assumptions do not materially affect the data.

18.5.2 Basis for claiming Estimated data as Actual

Below is detailed the justifications where estimated data has been claimed as actual data.

- Protection Relays - A significant number of protection relays do not have a commissioning date and these were apportioned based on the population of the units with dates. Other valid methods could be used to apportion the 1,956 relays with no dates, however it is judged to not have a material impact given the population of 20,294 total relays.

- Multiplex Assets - Energex's systems do not specifically record the date of installation that multiplex assets were installed. The volume of installed multiplex assets was estimated by apportioning the total amount of multiplex assets against the asset age profile of fibre optic cables. No other known valid method to do the apportionment is available.

- All Pilot Cables (called Communications Linear Assets in 5.4) – A significant proportion of fibre and copper pilot cables do not have installation dates (21%) and these were apportioned based on the population of the installations with dates. No other valid method is available to perform the apportionment.

19. BoP 2.8.3- Maintenance Cost Metrics

The AER requires Energex to provide the following information relating to Table 2.8.2:

- **Routine and non-routine maintenance costs by maintenance category as specified by the AER for each regulatory year.**

These variables are a part of Regulatory Template 2.8 – Maintenance

19.1 Consistency with CA RIN Requirements

Table 19.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 19.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
For expenditure incurred for the simultaneous inspection of assets and vegetation or for access track maintenance, report this expenditure under maintenance, not vegetation management.	Expenditure has been reported in accordance with this requirement.
For each of the maintenance subcategories prescribed in the Regulatory Template, add rows for additional subcategories if these are material and necessary to disaggregate financial or non-financial data, for example, to disaggregate asset groups according to voltage levels or to specify inspection/ maintenance cycles.	One additional row ("Other") has been added to table 2.8 from last CA RIN Energex provided.

19.2 Sources

Table 19.2 sets out the sources from which Energex obtained the required information.

Table 19.2: Information sources

Variable	Source
Actual Costs by Asset Category	DMA

19.3 Methodology

19.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

NAMP codes

- Energex builds its operating program according to Network Asset Management Plan (NAMP) codes. NAMP codes categorise lower level activities into higher level groups of like type work. For example, 'NAMP - BZ15 (11kV Circuit Breaker Maintenance)' contains maintenance work over many types of 11kV Circuit Breakers all with different criteria and cyclic frequencies.
- The NAMP codes are used for reporting purposes and were used by Energex for reporting progress to plan and delivery performance.
- Typically, NAMP codes are categorised by Asset Class or created specifically to measure key focus programs.

Mapping NAMP codes to RIN categories

- In order to meet the data requirements in Table 2.8.2, Energex's NAMP codes have been mapped to equivalent AER RIN categories in Ellipse (+NA2 table).
- Whilst the NAMP codes are not a one-for-one match with the RIN categories they were reasonably aligned.
- Where a single NAMP code related to multiple RIN categories, the RIN category that aligned the closest to the NAMP code was used. For example, 'NAMP - BZ25 (Oil analysis)' contains predominately oil sampling costs for Power transformers and associated tap changers. The NAMP code does, however, also include some costs for regulators and earth transformers. Therefore this NAMP code was mapped to 'Transformers – Zone Substation', as this type of equipment wore the most volume of work.

Planned and unplanned maintenance

- Energex has separate NAMP lines for 'planned' and 'unplanned/reactive' maintenance work. NAMP codes have been mapped In Ellipse (+NA2 table) accordingly to the 'routine' and 'non-routine' expenditure categories respectively in the AER table.

Underground cable maintenance

- Underground cable maintenance was apportioned between CBD and non-CBD based on the actual amount of 11kV underground cable in the CBD area relative to total 11kV cable in the network. Table 19.3 below provides the apportionment between CBD and non-CBD underground cable.

Table 19.3: Information sources

	Length of cable	Percentage of total
CBD	206 Kilometers	1.14%
Non-CBD	17,838 Kilometers	98.86%

19.3.2 Approach

Energex applied the following approach to obtain the required information:

- DMA report RIN001 was used to identify Routine and Non-Routine costs against each of the maintenance activity / categories.

19.4 Estimated Information

All information provided in Table 2.8.2 is Actual Information.

19.4.1 Justification for Estimated Information

19.4.2 Basis for Estimated Information

19.5 Explanatory notes

Other Costs Supplementary information

Energex has added a new "Other" Maintenance Activity to separately reflect:

- $832,895.50 in adjustments to actual costs, posted as an accrual at a high level only. Detailed entries are posted to projects in the following financial year. These amounts represent adjustments to the standard labour rates or oncost rates posted to projects throughout the year based on expected spend, with the adjustment reflecting the actual costs incurred.

- $136,622.77 in data quality recording issues.

20. BoP 2.9.1 - Emergency Response

The AER requires Energex to provide the following information relating to table 2.9.1- Emergency Response Expenditure (Opex):

- **Total emergency response expenditure**
- **Emergency response expenditure attributable to major events by identifying direct costs through a specific cost code for each major event or major storm. Major events most often refer to, but are not limited to, a major storm.**
- **Emergency response expenditure attributable to major event days by identifying**
- **Daily operating expenditure incurred on each date of those major event days and**
- **Summing up the expenditure for each event**

Actual Information was provided for all variables.

These variables are a part of Regulatory Template 2.9 – Emergency Response.

20.1 Consistency with CA RIN Requirements

Table 20.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 20.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In Table 2.9.1 provide the following - a) total emergency response expenditure b) emergency response expenditure attributable to major events by identifying direct costs through a specific cost code for each major event or major storm. Major events most often refer to, but are not limited to, a major storm. emergency response expenditure attributable to major event days by identifying daily operating expenditure incurred on each date of those major event days and summing up the expenditure for each event.	The variables supplied in RIN table 2.9 are across the entirety of the Energex network for each regulatory year.
Response to Issue 130 – CA RIN Issues Register: (B) is intended to capture costs where they can be attributable to particular events. (C) reflects all emergency response opex on days that were MEDs. The RIN instructions would ultimately result in a double reporting of costs in (B) and (C) where the event in your example triggers an MED. However the AER would expect to have visibility of opex on a daily basis under item (C) where the MED event is identified. The AER also wouldn't necessarily expect daily opex for events	Total emergency response costs were reported in section A. Total opex for specifically identified major events were reported in section B. Opex for MEDs were reported in section C.

Requirements (instructions and definitions)	Consistency with requirements
identified in (C) to sum up to amounts reported for the same event in (B) given other activity on those days.	
A Major Event Day SAIDI threshold is calculated for each year using the 2.5 beta method, and any day where the unplanned SAIDI exceeds this threshold is determined to be a Major Event Day.	Demonstrated in section 20.3
Emergency Response is defined in Appendix F of the CA RIN as: *Costs incurred to restore a failed component to an operational state including all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and/or repairs necessary.* *Costs of activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.*	Energex has reported costs from two activity codes, both of which conform to the AER's definition of Emergency Response.

20.2 Sources

Table 20.2 sets out the sources from which Energex obtained the required information.

Table 20.2: Information sources

Variable	Source
Emergency Response Expenditure by specific date	EPM FIN077 General Ledger Transactions
Total Emergency Response Expenditure	EPM FIN077 General Ledger Transactions

20.3 Methodology

20.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Major Event Days (MEDs) are determined in accordance with the STPIS definition.

- A Major Event Day SAIDI threshold is calculated for each year using the 2.5 beta method, and any day where the unplanned SAIDI exceeds this threshold is determined to be a Major Event Day.
- A major event is defined by the AER as any event that causes a breach of the major event day threshold. The costs reportable in section B are any costs that are recorded specifically against a major event using a work order.
- The Energex activity code 41300 – Corrective Maintenance is defined as:
  - The corrective repair of an asset or installation following an outage or fault. This is limited to the immediate repair work carried out to restore the asset to a temporary/permanent state in which it can perform its required function.
- This activity code as well as the dedicated activity code for emergency response (41400) was used to report costs as the definition above conforms to the AER's definition of Emergency Response stated in Appendix F of the CA RIN.

20.3.2 Approach

Energex applied the following approach to obtain the required information:

- Costs relating to Emergency Response activities are recorded under the activity headings 41300 and 41400.
- Overall costs for activities 41300 and 41400 were extracted from EPM FIN077 General Ledger Transactions.
- Major event day (MED) related costs at a work order/ transaction level were extracted using EPM FIN077 General Ledger Transactions.
- In both cases above, data was extracted for the 2015/16 financial year.
- Expenses were filtered to include only direct costs and on costs (overheads excluded), based on account elements (i.e. account element 8104 was excluded).
- Costs for identified major events and MEDs were extracted based upon the transaction date of the MEDs, as outlined above. Table 20.3 provides a list of the major events and the MEDs that occurred during the period.

Table 20.3: Major Events and MEDs

Year	Major events	Major event days
2015/16	Storms struck ENERGEX on …	• Sunday 29 November 2015 • Thursday 10 December 2015 • Saturday 4 June 2016 • Friday 24 June 2016

- Figures relating to specific major events were captured using unique work orders. The total direct costs and on costs (overheads excluded) were extracted for the major event work orders that had transactions on the specific major event days and are reported in section C.

20.4 Estimated Information

No Estimated Information was reported.

20.4.1 Justification for Estimated Information

Not applicable.

20.4.2 Basis for Estimated Information

Not applicable.

21. BoP 2.10.1- Overheads Expenditure

The AER requires Energex to provide the following variables relating to RIN Table 2.10.1 – Network Overheads Expenditure:

- **Allocation to SCS**
  - **Disaggregate network operating costs into six subcategories:**
    1. **network management;**
    2. **network planning;**
    3. **network control and operational switching personnel;**
    4. **quality and standard functions;**
    5. **project governance and related functions; and**
    6. **other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements**
- **Allocation to ACS**
  - **Disaggregate network operating costs into six subcategories:**
    1. **network management;**
    2. **network planning;**
    3. **network control and operational switching personnel;**
    4. **quality and standard functions;**
    5. **project governance and related functions; and**
    6. **other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements**
- **Allocation to Negotiated Services**
- **Allocation to Unregulated Services**
- **Capitalised Overheads**
  - **Disaggregate network operating costs into six subcategories:**
    1. **network management;**
    2. **network planning;**
    3. **network control and operational switching personnel;**
    4. **quality and standard functions;**
    5. **project governance and related functions; and**
    6. **other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements**

The AER requires Energex to provide the following variables relating to RIN Table 2.10.2 Corporate Overheads Expenditure:

- **Allocation to SCS**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting**

Statements not included in any other overhead subcategory

- **Allocation to ACS**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting Statements not included in any other overhead subcategory**
- **Allocation to Negotiated Services**
- **Allocation to Unregulated Services**
- **Capitalised Overheads**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting Statements not included in any other overhead subcategory**

All information is Actual Information.

These variables are a part of Regulatory Template 2.10 – Overheads.

21.1 Consistency with CA RIN Requirements

Table 21.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 21.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Report overhead expenditure before it is allocated to services or direct expenditure, and before any part of it is capitalised.	Expenditure in Table 2.10.1 is consistent with the requirement for 'overhead expenditure before allocation'. The expenditure presented is before allocation and capitalisation.
Energex must disaggregate network operating costs into the following six subcategories: (a) network management (b) network planning (c) network control and operational switching personnel (d) quality and standard functions (e) project governance and related functions (f) other.	Appendix 6 – Explanation of functional areas explains the classification of services into the below categories- • Network management; • Network planning; • Network Control; • Operational Switching • Quality and Standard Functions; and Project Governance.
For the avoidance of doubt, the following expenditures must be provided in regulatory template 2.10: a) If Energex has previously reported network operating costs in its Regulatory Accounting Statements, Energex must report these under network overhead in regulatory template 2.10.1: i. network management ii. network planning	Network overheads expenditure for 2015/16 has been categorised into the following subcategories: *Mandatory* • Network Management • Network Planning • Network Control and Operational Switching Personnel

Requirements (instructions and definitions)	Consistency with requirements
iii. network control and operational switching personnel iv. quality and standard functions (including standards and manuals, compliance, quality of supply, reliability, network records (GIS), and asset strategy (other than network planning) v. project governance and related functions (including supervision, procurement, works management, logistics and stores) vi. other (including training, OH&S functions, network billing, and customer service). The six subcategories above are mandatory subcategories in network overhead. b) Regulatory template 2.10.1 Network Overhead – For other network operating costs that Energex previously reported in its Regulatory Accounting Statements and are not included in the six mandatory subcategories above, Energex must report these under network overhead in regulatory template 2.10.1. These expenditures include, but are not limited to: i. meter reading ii. advertising/marketing iii. Guaranteed Service Level (GSL) payments iv. National Energy Customer Framework (NECF)-related expenses v. feed-in tariffs vi. demand management expenditure vii. levies c) For corporate overhead expenditure that Energex previously reported in its Regulatory Accounting Statements and are not included in any other overhead subcategory, Energex must report these under corporate overhead in regulatory template 2.10.2. These expenditures include, but are not limited to: i. office of the CEO ii. legal and secretariat iii. human resources iv. finance v. regulatory vi. insurance vii. self-insurance viii. debt raising costs ix. equity raising costs	• Quality and Standard Function • Project Governance and related Functions – Logistics and stores (POW Material Management) – Procurement – Project Governance – Supervision – Project Governance – Works Management • Training and Development • OHS • Customer Services *Optional* • Meter Reading, Network Billing & Metering Support • DSM Initiatives • Levies • Network Property Corporate overheads expenditure for 2015/16 has been categorised into the following subcategories: • Office of CEO • Legal and Secretariat • Audit • Strategy and Regulation • Human Resources • Finance • Business Support Services • Business Operations and Performance • Field Support Services • Stakeholder Engagement and Management • Other Operating • Corporate Restructuring • IT and Communications • Property • Fleet Debt Raising Costs

Requirements (instructions and definitions)	Consistency with requirements
x. non-network IT support.	
If there is any overhead expenditure that is capitalised, explain in the Basis of preparation document(s), why it is capitalised.	Energex's capitalisation policy explains that Energex's core business is the construction, maintenance and operation of the electricity distribution network in South East Queensland. In the operation of its business, Energex incurs a range of support costs that are not directly attributable to individual distribution services or activities. As these costs support the direct activities associated with both the construction and maintenance of the electricity network, Energex has employed a rational and systematic approach, to attribute these support costs to operating and capital activities, which is described in its Cost Allocation Methodology (CAM). In accordance with Energex's CAM, approved by the AER, regulated overheads are allocated to distribution services (capital and operating) based on direct spend incurred on each service as this reflects a strong correlation with the consumption of the underlying overhead expenditure.

21.2 Sources

Table 21.2 sets out the sources from which Energex obtained the required information.

Table 21.2: Information sources

Variable	Source
Network Overhead – 2015/16	• Ellipse general ledger report (FIN073) • Annual Performance RIN and excel work files
Corporate Overhead – 2015/16	• Ellipse general ledger report (FIN073) • Annual Performance RIN and excel work files

21.3 Methodology

The approaches that were taken to report overhead expenditure into the categories in the CA RIN were as follows:

21.3.1 Assumptions

No assumptions were made.

21.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Obtained general ledger (GL) reports that provide account balances for expenses, detailing the nature of items via codes that identify the group that incurred the expense (Responsibility Centre), the work being performed (Activity), and the type of expense (Element).

   Expense accounts were then mapped based on the definitions of Network Overheads and Corporate Overheads included in Appendix F of the CA RIN.

   Note: some items identified by Energex as direct costs and reported accordingly in the Annual Performance (AP) RIN, needed to be mapped to Network Overheads for CA RIN reporting. These included Network Operations, DSM Initiatives, Levies, Customer Service, Network Billing and Other Energy Market Services functions.

2) Mapped the account codes:

   a. That specifically related to SCS, ACS, unregulated services;

   b. As network or corporate overhead;

   c. Into functional areas (which represent the sub-categories of network and corporate overheads), principally on Responsibility Centre and Activity, as detailed in Appendix 6 – Explanation of functional areas.

   Note: Functional areas are per the mandatory categories defined in the CA RIN and additional categories as provided for in Energex's current AP RIN.

   d. As capitalisable (costs allocated to direct control services based on direct spend, in accordance with Energex's approved CAM) or non-capitalisable costs (these costs remain as 100% operating expenditure and are allocated to services in accordance with Energex's approved CAM).

21.4 Estimated Information

No Estimated Information was reported.

21.4.1 Justification for Estimated Information

Not applicable.

21.4.2 Basis for Estimated Information

Not applicable.

21.5 Explanatory notes

Corporate Overheads for Corporate Restructuring began in 2011/12 as a result of Energex's conscious effort to reduce costs and employee numbers. This has resulted in the payment of termination benefits since the commencement of the restructuring.

22. BoP 2.11.1 - Labour

The AER requires Energex to provide the following information relating to Table 2.11.1 – Labour Cost Metrics per Annum:

- **ASLs (Average Staffing Levels)**
- **Total Labour Cost**
- **Average Productive Working Hours per ASL**
- **Stand Down Occurrences per ASL**

This information is required to be provided for all labour categories as defined by the AER, split into Corporate Overheads, Network Overheads and Direct Network Labour.

The AER requires Energex to provide the following information relating to Table 2.11.2 – Extra Labour Descriptor Metrics for Current Year (2015/16):

- **Average Productive Work Hours Per ASL - Ordinary Time**
- **Average Productive Work Hours Hourly Rate Per ASL - Ordinary Time**
- **Average Productive Work Hours Per ASL - Overtime**
- **Average Productive Work Hours Hourly Rate Per ASL – Overtime**

This information is required to be provided for all labour categories as defined by the AER, split into Corporate Overheads, Network Overheads and Direct Network Labour.

These variables are part of worksheet 2.11 – Labour.

22.1 Consistency with CA RIN Requirements

Table 22.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 22.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Only labour costs allocated to the provision of SCS should be reported in the labour cost sections of Regulatory Template 2.11. Labour used in the provision of contracts for both goods and services, other than contracts for the provision of labour (i.e. labour hire contracts) must not be reported in these regulatory templates. Energex must break down its labour data (both employees and labour contracted through labour hire contracts) into the Classification Levels provided in Regulatory Template 2.11. Energex must explain	Energex general ledger (GL) system (Ellipse) uses GL account codes to capture transaction information. This includes the department (Responsibility Centre), functions being performed (Activity), product or service delivered to external customers and the nature of income or expense (Element). Energex uses the GL code to extract only the labour related cost (Element) for standard control services (a combination of Responsibility Centre and Activity).

Requirements (instructions and definitions)	Consistency with requirements
how it has grouped workers into these classification levels.	Energex labour categories allocated (via employee timesheets) to GL transactions have been mapped to the relevant labour categories required in the CA RIN. For further details please refer to Section **Error! Reference source not found.** Assumptions and Approach.
Labour related to each classification level obtained through labour hire contracts may be reported separately on separate lines to employee based labour. If Energex wishes to do this they should add extra lines in the regulatory template below each classification level for which it wishes to separately report labour hire.	Costs related to labour hire have been combined with Energex internal labour in the table.
Quantities of labour, expenditure, or stand down periods should not be reported multiple times across labour regulatory templates. However, labour may be split between Regulatory Templates (for example one worker could have half of their time allocated to corporate overheads and half of their time to network overheads).	All figures were split between the mutually exclusive categories of corporate overheads, network overheads and network direct. The method of allocation is noted in Section **Error! Reference source not found. Error! Reference source not found.**.
The ASLs for each classification level must reflect the average Paid FTEs for each Classification Level over the course of the year.	Energex converted labour costs captured in the GL system into ASLs which represents the average Paid ASLs for each Classification Level over the course of each year.
'Per ASL' values are average values per ASL in each classification level. For example, the average productive work hours per ASL would equal the total productive work hours associated with labour in the classification level divided by the number reported in Annual Totals – ASLs for the classification level (i.e. the number of ASLs in the classification level).	This has been calculated as per the AER's instructions. For further details please refer to Section **Error! Reference source not found. Error! Reference source not found.**.
Stand down periods must be reported against the relevant classification level in the regulatory template containing the relevant labour. For example, a stand down of an electrical line apprentice would be reported against the apprentice classification level in the Total network direct internal labour costs regulatory template.	This was calculated as per the AER's instructions. For further details please refer to Section **Error! Reference source not found. Error! Reference source not found.**.

22.2 Sources

The following reports were extracted from the Ellipse system:

- General ledger balance ($ and hours) by labour category and element;
- General ledger transactions of 9 hour breaks by labour category; and
- General ledger balances ($) of labour hire.

The following reports were extracted from the Human Resource Information System (HRIS) or provided by the Energex Payroll and HR Systems Team:

- Labour category breakdown of labour hire;
- 9 day and 10 day fortnightly work arrangement breakdown of internal labour; and
- Stand Down occurrences.

The following reports were extracted by the Energex Business Performance & Analysis team:

- Standard Labour available hours by labour category; and
- Standard Labour rate by category.

Table 22.2 sets out the sources from which Energex obtained the required information.

Table 22.2: Information sources

Variable	Source
Table 2.11.1 – Labour Cost Metrics per Annum	
ASLs	Ellipse (GL, payroll and HR information), Standard labour rates and hours (Energex Business Performance & Analysis)
Total Labour Cost – Actual, Budget and Forecast	Ellipse (GL), Standard labour rates and hours (Energex Business Performance & Analysis)
Average Productive Working Hours per ASL	Standard labour rates and hours (Energex Business Performance & Analysis)
Stand Down Occurrences per ASL	Ellipse (HR)
Table 2.11.2 – Extra Labour Descriptor Metrics for Current Year (2015/16)	
Average Productive Work Hours Per ASL -	Standard labour rates and hours (Energex

Variable	Source
Ordinary Time	Business Performance & Analysis)
Average Productive Work Hours Hourly Rate Per ASL - Ordinary Time	Ellipse (GL)
Average Productive Work Hours Per ASL - Overtime	Standard labour rates and hours (Energex Business Performance & Analysis), Ellipse (GL)

22.3 Methodology

Information in the Labour Regulatory Template was based on actual transactions from the General ledger and payroll system. Minor adjustments were made where appropriate to comply with requirements set by the AER.

22.3.1 Assumptions & Approach

Energex applied the following approach to obtain the required information:

1) The following GL labour data was obtained from Ellipse:
   a. Dollars
   b. Hours
   c. Ordinary time
   d. Overtime
   e. GL code
   f. Labour category

2) Each GL code was mapped into the categories required in the labour worksheet. The classifications are consistent with Energex's 2015/16 Cost Allocation Methodology (CAM). The classification of the GL codes can be seen in Table 22.3 below:

Table 22.3: Information sources

CA RIN Category	Energex GL code
Corporate overhead	Corporate support cost
Network overhead	Customer Call Centre DSM Direct Levies Network operations

CA RIN Category	Energex GL code
Network direct	SCS Direct Opex (Program of Work) SCS Direct Capex *(Excludes all fleet and material on-costs and general overhead)*

ASLs and Total Labour Costs

1) Each Energex labour category extracted from Ellipse was classified into the required AER categories as set out in Table 23.4 over page. The standard annual dollars/FTE for each labour category (Energex Business Performance & Analysis team) was then used to convert the total labour dollars into ASLs.

   The mapping of Energex labour categories to AER categories has been approved by Energex management and incorporated into a system report that enables the extraction of labour data against the AER categories directly from the Energex reporting software.

Table 23.4: Labour classification categories

		2015/16
Energex	**AER**	**Annual Hours**
ADMN	SUPPORT STAFF	1,678
APPR	APPRENTICE	1,575
CONT	PROFESSIONAL	1,678
ELEC	SEMI PROFESSIONAL	1,575
EXE1	MANAGER	1,678
EXE2	SENIOR MANAGER	1,594
NEXE	PROFESSIONAL	1,678
PARA	SEMI PROFESSIONAL	1,678
PROF	PROFESSIONAL	1,678
PWKR	UNSKILLED WORKER	1,575
SPEB	MANAGER	1,678
SPVR	SEMI PROFESSIONAL	1,678
SYSO	SEMI PROFESSIONAL	1,678
TECH	SKILLED ELECTRICAL WORKER	1,575
EMT	EXECUTIVE MANAGER	1,594

It is noted that Executive managers, as specified in the CA RIN, were contained in the Energex labour classification EXE2. These positions were manually extracted in compliance with the CA RIN instructions. The remainder of EXE2 was then classified as Senior Managers.

2) Once labour costs had been calculated the termination payments and FBT payments were added to the labour cost figures. The termination payments were obtained from HR data and verified against the GL. FBT information was provided by the Energex Corporate Tax team.

Training costs were excluded as this data was unavailable for inclusion. However, it is noted that these costs were immaterial for the purpose of this report (less than $2M as per the GL).

Average Productive Work Hours per ASL

1) Total available hours were converted into productive hours by subtracting the known hours of training assigned to each employee type. The following figures were subtracted from the available hours to convert to productive hours:
   a. Apprentice: 315 hours per year
   b. All other labour categories: 24 hours per year i.e. three days

Stand down Occurrences per ASL

1) Transactional data for enforced 9 hour breaks (which constitutes a stand down occurrence) can be identified in the HR payroll system using an earning code. The number of stand down occurrences was calculated as the frequency of transactions in each labour category.

2) 9 hour break transactional data cannot be identified by service classification as this information is only captured by employee. In addition, the 9 hour break transactions are recorded as overhead costs in Energex's payroll system, however these transactions relate to employees working across Corporate Support, Network Overheads and Network Directs. If the figures for Network Overhead ASLs only were used as the denominator rather than total headcount, it will significantly distort the stand-down occurrence per ASL.

3) To report this measure, Energex has adopted the following formula to calculate the figures for Stand Down Occurrences per ASL:

$$\frac{Number\ of\ Stand\ Down\ Occurrences}{Total\ ASLs}$$

Assumptions and Approach Explanatory Notes

The following is noted in relation to the above:

- Some journals within the GL data were processed without labour categories. Where this occurred, the balance was allocated proportionally across all labour categories within each functional area. It should be noted this amount is considered immaterial (less than 3% of Total Labour Costs).

- Redundancy Expenses were excluded from the calculation of hourly labour rates as these expenses cannot be linked to hours worked per employee and would distort the data if included.

Labour Hire

1) Labour hire data was captured using the GL code element 4920.

2) Actual amounts (excluding capital expenditure which was specifically identified as contractor costs) were used as the best representations of Energex's labour hire spend.

3) Labour hire data within the GL is not disaggregated by labour category, therefore the labour hire figures were split into the labour categories using a pro-rata methodology based on the known total labour hire (60% Support Staff/26% Professional/14% Unskilled Worker – source: HR).

Table 2.11.2 - Extra Descriptor Metrics For Current Year (2015/16)

The following process was used to calculate extra descriptor metrics for the 2015/16 regulatory year:

1) GL transactions were extracted to show both the Ordinary and Overtime components of labour dollars and hours.

2) The average productive work hours per ASL for ordinary hours was extracted directly for each labour category based on standard available hours.

3) Average productive work hours hourly rate for ordinary time was calculated as the total costs for ordinary time divided by the number of ASLs to give an average cost per ASL. This was then divided by the average productive work hours per ASL extracted above to give an hourly rate per ASL.

4) Average productive work hours hourly rate per ASL for overtime was calculated as the total overtime cost extracted from Ellipse divided by the total overtime hours worked.

22.4 Estimated Information

22.4.1 Justification for Estimated Information

Not applicable.

22.4.2 Basis for Estimated Information

Not applicable.

22.5 Explanatory notes

Reporting where relevant labour classifications are unavailable

In some instances, Energex's mapping of labour categories to AER classifications produced results which are unable to be populated against the relevant classifications. This applies for Corporate Overheads, Network Overheads and Network Directs, which have been populated into the Master templates as detailed below.

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

These classifications were applied as there was no data (or limited data in the case of Apprentices) already populated against these classifications and therefore doesn't distort the figures reported.

23. BoP 2.12.1 - Input Tables

The AER requires Energex to provide the following information in Regulatory Template 2.12 Input Tables:

- **Direct material costs**
- **Direct labour costs**
- **Contract costs**
- **Other costs**
- **Related party contract cost**
- **Related party contract margin**

For each of the following Service Categories:

- **Vegetation Management**
- **Routine Maintenance**
- **Non-routine Maintenance**
- **Overheads**
- **Augmentation**
- **Connections**
- **Emergency Response**
- **Public Lighting**
- **Metering**
- **Fee Based Services**
- **Quoted Services**
- **Replacement**
- **Non-Network**

These variables are a part of Regulatory Template 2.12 – Input Tables

A separate Basis of Preparation has been prepared for the disaggregation of related party costs for all variables.

23.1 Consistency with CA RIN Requirements

Table 23.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 23.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Direct costs Operating or capital expenditure directly attributable to a work activity, project or work order. Consists of in-house costs of direct labour, direct materials, contract costs, and other attributable costs. Excludes any allocated overhead.	Energex has reported all direct costs in accordance with the categories specified in RIN Table 2.12, which balance to the regulatory accounts where applicable.
Direct materials Materials are the raw materials, standard parts, specialised parts and sub-assemblies required to assemble or manufacture a	Refer above.

Requirements (instructions and definitions)	Consistency with requirements
network/non-network asset or to provide a network/non-network service. *Direct materials* costs are attributable to a specific asset or service, cost centre, or work order, and exclude materials provided under external-party contracts. Includes: • the cost of scrap • normally anticipated defective units that occur in the ordinary course of the production process • routine quality assurance samples that are tested to destruction the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: • Labour hire; and • Ordinary time earnings; and • Other earnings, on-costs and taxes; and Superannuation.	Refer above.
Contract A legally binding contract.	Refer above.

23.2 Sources

Opening data for overheads, fee based services, quoted services was sourced directly from the annual regulatory accounts, work papers and/or from general ledger reports.

Table 23.2 sets out the sources from which Energex obtained the required information.

Table 23.2: Information sources

Variable	Source
Network Overheads	Annual regulatory accounts and/or general ledger reports.
Corporate Overheads	Annual regulatory accounts and/or general ledger reports.

Variable	Source
Fee Based Services and Quoted Services	General ledger reports
Non-Network – IT and Communications	• SPARQ Solutions information based on invoices issued to Energex; • Capex expenditure per Ellipse Accounting Entry Report for activities C3061, C3064, C3060, C3050 and C3051 • Profit and Loss from EPM for SPARQ Solutions division for MOPEX RC 1020for 15/16 Mapping table for allocation of cost element to the Input Tables categories (Appendix 5 – Cost Element Mapping to Input Table Categories). Provided by Regulatory Accounting division.

Non-Network – Motor Vehicles	• Ellipse Financial Reports:
	  – Profit & Loss Reports
	  – Capex Summary Reports
	  – Detailed Transaction Reports
	• Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited)
	• Previous Annual Performance RIN Capex reports provided by Energex External Reporting team
	• Discussions with Department Managers
	• Operating Expenditure Reports from SG Fleet Australia Pty Limited (our Fleet Managers) to allocated cost per Asset Category
	
	Mapping table for allocation of cost element to the Input Tables categories (Appendix 5 – Cost Element Mapping to Input Table Categories) provided by Regulatory Accounting division.

Non-Network – Buildings and Property	• Profit and Loss Report by RC 2510 • EPM Report – FIN077 Transactions Report for RC 2510 all indirect and CAPEX activities. • Regulatory Accounts Mapping table for allocation of cost element to the Input Tables categories (Appendix 5 – Cost Element Mapping to Input Table Categories) Provided by Regulatory Accounting division.
Non-Network – Other (Combined Motor Vehicle and Property)	**Property 'Other'** • EPM Report – FIN077 Transactions Report for RC 2510

Variable	Source
	CAPEX activities. • Mapping table for allocation of cost element to the Input Tables categories (Appendix 5 – Cost Element Mapping to Input Table Categories). Provided by Regulatory Accounting division. **Motor Vehicles Other** • Ellipse Financial Reports: – Profit & Loss Reports – Capex Summary Reports – Detailed Transaction Reports • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) • Previous Annual Performance RIN Capex reports provided by Energex External Reporting team • Discussions with Department Managers • Operating Expenditure Reports from SG Fleet Australia Pty Limited (our Fleet Managers) to allocated cost per Asset Category Mapping table for allocation of cost element to the Input Tables categories (Appendix 5 – Cost Element Mapping to Input Table Categories). Provided by Regulatory Accounting division.
Vegetation Management	EPM Report – FIN077 Transactions Report
Routine Maintenance	Distribution Monitoring Analytics (DMA) Solution
Non-routine Maintenance	Distribution Monitoring Analytics (DMA) Solution
Augmentation	EPM Super User Query
Connections	EPM Report – FIN077 Transactions Report
Emergency Response	EPM Report – FIN077 Transactions Report
Public Lighting	EPM Report – FIN077 Transactions Report
Metering	Peace, Ellipse, Business Objects Reports
Replacement	Distribution Monitoring Analytics (DMA) Solution

23.3 Methodology

Overheads, Fee Based and Quoted Services

- Energex has sourced the required information from the annual regulatory accounts, work papers and/or supporting general ledger reports. Information was then categorised based on the relevant cost elements.

All other elements

- The figures in RIN Table 2.12 are based on the figures generated for each of the respective Regulatory Templates. These figures were then distinguished between the required input table categories by mapping the cost elements within the base data. The mapping table can be found in Appendix 5 – Cost Element Mapping to Input Table Categories.

23.3.1 Assumptions

- Information is based on the audited annual regulatory accounts, work papers and/or supporting ledger reports.
- Energex has consistently reported direct costs throughout the CA RIN. This means that overhead expenditure recorded against the overheads variables in table 2.12 has not been duplicated via inclusion in expenditure reported against other variables within the table.
- It is assumed that the “Major Storms” category within the Emergency Response section relates to the total costs reported in section B of Regulatory Template 2.9.

23.3.2 Approach

Overheads

- There is a direct relationship between the individual cost elements and the required categories, which is established via the element hierarchy. For example, the cost element for ordinary time labour is under the hierarchy for employee benefits, which maps to the category for Direct Labour Cost. A summarised mapping table is provided in Appendix 5 – Cost Element Mapping to Input Table Categories.
- Separate mapping to Network Overheads and Corporate Overheads is in accordance with the mapping applied for Regulatory Template 2.10.
- A proportional allocation method was applied to facilitate the assignment of regulatory reporting adjustments to the respective cost categories. This was because adjustments for regulatory purposes were undertaken at the total dollar value amount and not at the individual cost element. The allocation was applied

based on the direct proportion of expenditure reported in the general ledger for the respective categories.

Fee Based and Quoted Services

- The distribution of direct costs by activity and cost elements was generated from general ledger reports. This information was then reconciled back to the annual regulatory accounts, work papers and/or supporting documents.

- There is a direct relationship between the individual cost elements and the required categories, which is established via the element hierarchy in the general ledger Chart of Accounts (COA). For example, the cost element for ordinary time labour is under the hierarchy for employee benefits, which is mapped to the category for Direct Labour Cost. A summarised mapping table is provided as Appendix 5 – Cost Element Mapping to Input Table Categories.

Non-Network - IT and Communications

- The IT and Communications figure was calculated as the sum of the following items from Regulatory Template 2.6 broken down into each input table category (for details of the methodology for figures stated in 2.6 please refer to the relevant Basis of Preparation):

- Client Device Expenditure Opex ($'0) – The expenditure from SPARQ Solutions to Energex is allocated to "Contractor Costs" as per the conversion table found in Appendix 5 – Cost Element Mapping to Input Table Categories.

- Client Device Expenditure Capex ($'0) – The identified client devices were grouped by cost element and allocated as per the conversion table found in Appendix 5 – Cost Element Mapping to Input Table Categories.

- Recurrent Expenditure Opex ($'0) – These items were reconciled to the SPARQ Solutions accounts and allocated based as per the conversion table provided in Appendix 5. Total "Contractor Costs" for Recurrent Expenditure is calculated less the "Contractor Costs" Client Device Expenditure. Negative numbers seen for "Other Costs" reflect transfers to Metering Dynamics of telecommunication costs and the transfer of small capex purchases.

- Recurrent Expenditure Capex ($'0) is calculated as the difference between total Energex ICT Capex as recorded in the Regulatory accounts less the client devices capex calculated above. The identified non-client devices were grouped by element and allocated as per conversion table provided in Appendix 5 – Cost Element Mapping to Input Table Categories.

- Non-recurrent Opex ($'0) – The expenditure was allocated to "Contractor Costs" as per conversion table provided in Appendix 5 – Cost Element Mapping to Input Table Categories.

Non-Network - Buildings and Property

- The Buildings and Property figures were calculated as the sum of the following items from Regulatory Template 2.6 broken down into each input table category (for further details of the methodology for figures stated in Regulatory Template 2.6 please refer to the relevant Basis of Preparation):

- Building & Property Opex – The expenditure from Regulatory Template 2.6 was allocated between “Direct Material Costs”, “Direct Labour Costs”, “Contractor Costs” and “Other Costs” as per the conversion table provided in Appendix 5 – Cost Element Mapping to Input Table Categories. Non-regulated and network expenditure were not included in the calculations.

- Buildings & Property Capex – The figure contained data extracted directly for Buildings and Property from the transaction report and then broken up into “Direct Material Costs”, “Direct Labour Costs”, “Contractor Costs” and “Other Costs” as per the conversion table provided in Appendix 5 – Cost Element Mapping to Input Table Categories.
  – The figures included direct expenditure and on-costs but excluded general overheads in accordance with Energex AER approved CAM. These figures also include non-system land purchases and exclude the amounts separated into other expenditure for furniture.

Non- Network - Other Expenditure

- The other expenditure figures related to “Property” were calculated as the sum of the items below. The first two items relate to the “Other – Office Furniture” in Regulatory Template 2.6. The third item relates to the “Other – Plant and Equipment” figure in Regulatory Template 2.6.

- Other Expenditure Capex ($’0) – The percentage split between “Direct Material Costs”, “Direct Labour Costs”, “Contractor Costs” and “Other Costs” was identified by activity from the accounting entry reports and using the conversion table provided in Appendix 5 – Cost Element Mapping to Input Table Categories.

- Other Plant & Equipment Expenditure Capex ($’0) – The expenditure relating to the Manual Handling Systems and Sweeper/Scrubber was allocated to “Other Expenditure - Contractor Costs” as this expenditure was paid through contractors undertaking the Geebung development.

- All “Other” expenditure reported for Motor Vehicles in Regulatory Template 2.6 was classified into Direct Materials, Direct Labour, Contract and Other Costs using the cost element mapping table found in Appendix 5 – Cost Element Mapping to Input Table Categories. Once classified the following variables were added together to give a total for other expenditure:
  – Other Non-Network Expenditure Fleet
  – Other Motor Vehicles Generators
  – Other - Tools & Equipment

- The “Other” expenditure total figure was then calculated as the sum of the “Other” items for Motor Vehicles, ICT and Property.

Non-Network - Motor Vehicles Expenditure

- Figures for motor vehicles expenditure were calculated for Regulatory Template 2.6. For details of the calculation please refer to the Basis of Preparation for Regulatory Template 2.6.

- The figures for motor vehicles were calculated from data that classified each expense by the cost element. These cost elements were used along with the mapping table found in Appendix 5 to classify the motor vehicles expenses into the categories required in Regulatory Template 2.12. Each category (Cars, Light Commercial Vehicles, Elevated Work Platforms and Heavy Commercial Vehicles) was then summated to give the final figure per Direct Materials, Direct Labour, Contract and Other Costs.

Vegetation Management

- The vegetation management costs were developed by zone within Regulatory Template 2.7 – Vegetation Management. For full details of the development of the vegetation management figures please refer to the Basis of Preparation for Regulatory Template 2.7.

- The vegetation management costs were developed from reports which detailed the figures by cost element. These cost elements were used in conjunction with the mapping table found in Appendix 5 to split the total costs for each region into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs.

Routine and Non-routine Maintenance

- Routine and non-routine maintenance figures were developed from the Energex Network Asset Management Plan (NAMP) codes within Regulatory Template 2.8. For full details please refer to the Basis of Preparation for maintenance cost metrics.

- The maintenance costs were extracted with Energex cost elements when being developed for Regulatory Template 2.8. This allowed each expense to be mapped into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs using the mapping table with Appendix 5. The costs for the 2015/16 financial year were then summated to obtain the routine and non-routine maintenance figures in Regulatory Template 2.12.

Augmentation

- Figures for augmentation expenditure broken down into the required categories (Subtransmission substations, Subtransmission lines, HV feeders, Distribution substations, LV feeders and Other assets) were calculated for Regulatory Template 2.3 – Augex in RIN Table 2.3.4. These figures were generated from project costs that were grouped into the required categories. For full details please refer to the Basis of Preparation for RIN Table 2.3.4.

- The costs for each classified project were able to be broken down into their respective cost elements. These were then used with the mapping table in Appendix 5 to generate Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost figures per project. The project level figures were then summated using the project classifications used in RIN Table 2.3.4 to produce the figures for the input tables Regulatory Template.

Connections

- The figures for connections were apportioned to labour, material, contract and other cost categories based expenditure for 2015/16, under financial activity codes C2010, C2510, C2550, C2570, C3510 and C3540, (less gifted assets). The expenditure figures were able to be broken up into the required cost categories.

Emergency Response

- The figures for “Major Storms” in Regulatory Template 2.12 were calculated using the figures found in section B of Regulatory Template 2.9 – Emergency Response. These numbers in Regulatory Template 2.9 were generated by extracting all expenditure relating to specific major event work orders. The costs under each of these work orders were able to be split into cost elements and mapped to the Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost categories using the table in Appendix 5 – Cost Element Mapping to Input Table Categories.

- The figures for “Major Event Days” in Regulatory Template 2.12 were calculated using the figures found in section C of Regulatory Template 2.9 Emergency Response. The figures in Regulatory Template 2.9 were calculated by breaking down the cost of each day into their respective costs elements and mapping them to Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost categories using the table in Appendix 5 – Cost Element Mapping to Input Table Categories.

Public Lighting

- For the 2015/16 period the maintenance costs and capital costs were split using the mapping table in Appendix 5 and the EPM report FIN077.

Metering

- The metering values in Regulatory Template 2.12 were calculated using the expenditure figures stated in RIN Table 4.2.2. For the full details of the calculation of each of these figures please refer to the Basis of Preparation for Regulatory Template 4.2.

- The expenditure figures for each year were classified into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs based upon the logic detailed in Table 23.3 below:

Table 23.3: Information sources

Metering Expenditure Service Subcategory	Classification Methodology
Meter Purchase	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter purchases were 100% allocated to Direct Material Costs.
Meter Testing	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs.
Meter Investigation	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs.
Scheduled Meter Reading	Scheduled meter reading in Energex is performed only by contractors and was classified as 100% Contractor Costs. All data in RIN Table 4.2.2 was derived from invoices paid to contractors.
Special Meter Reading	Special meter reading in Energex is performed only by contractors and was classified as 100% Contractor Costs. All data in RIN Table 4.2.2 was derived from invoices paid to contractors.
New Meter Installation	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs.
Meter Replacement	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs.
Meter Maintenance	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs.

Each service subcategory for Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs was then summated to give the figures reported in Regulatory Template 2.12 – Input Tables.

Replacement

- Figures for replacement expenditure broken down into the required categories (Poles, Cables, and Transformers etc.) were calculated for Regulatory Template 2.2 – Repex in RIN Table 2.2.1. These figures were generated from project costs that were grouped into the required categories. For full details please refer to the Basis of Preparation for RIN Table 2.2.1.
- The costs for each classified project were able to be broken down into their respective cost elements. These were then used with the mapping table in Appendix

5 – Cost Element Mapping to Input Table Categories to generate Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost figures per project. The project level figures were then summated using the project classifications used in RIN Table 2.2.1 to produce the figures for Regulatory Template 2.12 – Input Tables.

23.4 Estimated Information

23.4.1 Justification for Estimated Information

23.4.2 Basis for Estimated Information

23.5 Explanatory notes

- For detailed explanatory notes please refer to the Basis of Preparation 2.6.1, 2.6.2 and 2.6.3 (IT and Communication, Fleet and Equipment and Property respectively).
- In must be noted that there can sometimes be a small delay between when an invoice is paid and the asset is commissioned. If either of these circumstances span a financial year, a disconnect between financial transactions and physicals (when the asset is actually commissioned) occurs.
- Negative numbers seen for “Other Costs” (ICT) reflect transfers to Metering Dynamics of telecommunication costs and the transfer of small capex purchases.
- Negative numbers seen for Quoted Services “Other Expenditure” relates to accounting entries processed each month to accrue Work In Progress balances to the Balance Sheet. All entries are processed on a generic Element and reverse the following month.

Note: Some Non-Network information was provided by the Energex fleet management company, SG Fleet Australia Pty Limited, which was based on invoice payments per motor vehicle category – this was considered Actual information.

24. BoP 2.12.2- Input Tables Related Party Costs

The AER requires Energex to provide the following information in Regulatory Template 2.12 - Input tables

Related party contractor costs, split by the following categories:

- **Vegetation Management**
- **Routine Maintenance**
- **Non-Routine Maintenance**
- **Overheads**
- **Augmentation**
- **Connections**
- **Emergency Response**
- **Public Lighting**
- **Metering**
- **Fee-based Services**
- **Quoted Services**
- **Replacement**
- **Non-Network Expenditure**

Actual Information was provided for all variables.

This information forms part of Regulatory Template 2.12 Input tables.

24.1 Consistency with CA RIN Requirements

Table 24.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 24.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Related Party In relation to Energex, any other entity that: • had, has or is expected to have control or significant influence over Energex; • was, is or is expected to be subject to control or significant influence from Energex; • was, is or is expected to be controlled by the same entity that controlled, controls or is expect to control Energex—referred to as a situation in which entities are subject to common control; • was, is or is expected to be controlled by the same entity	Energex has reported all relevant related party costs reported in the regulatory accounts in accordance with the categories specified in this CA RIN table. Note that as a consequence of the Queensland Energy Consolidation on 30 June 2016, Energex and Ergon Energy have become more closely related and will be required to make associated related party

Requirements (instructions and definitions)	Consistency with requirements
that significantly influenced, influences or is expected to influence Energex; or • was, is or is expected to be significantly influenced by the same entity that controlled, controls or is expected to control Energex; but excludes any other entity that would otherwise be related solely due to normal dealings of: • financial institutions; • authorised trustee corporations as prescribed in Schedule 9 of the Corporations • Regulations 2001 (Cth); • fund managers; • trade unions; • statutory authorities; • government departments; • local governments and includes Energex Limited (ACN 078 849 055); or ·where any of the entities identified in sub-paragraphs (a) to (e) have novated or assigned a contract or arrangement to or from another entity (where that contract or arrangement relates to the provision of distribution services by Energex, the entity to whom that contract or arrangement has been novated or assigned.	disclosures for future RIN reporting. Given this relationship only commenced on 30 June 2016, no related party disclosures have been included in the 2015/16 RIN.
Related party contract A finalised *Contract* between Energex and a *Related Party* for the provision of goods and/or services.	**Refer Above**
Related party margin The dollar amount of profit a *Related Party* gains above its total actual costs under a *Related Party Contract* with Energex. This profit may include margins, management fees or incentive payments.	Related party transactions reported are at cost so there is no margin.

24.2 Sources

Table 24.2: Information sources

Category	Source
SPARQ	Ellipse system and EPM Profit or Loss Reports

Category	Source
Energy Impact	Ellipse system and EPM Accounting Entry Reports

24.3 Methodology

Energex sourced the relevant information from Ellipse system and categorised the information as required in the CA RIN Table based on the nature of the transactions.

24.3.1 Assumptions

- As a consequence of the Queensland Energy Consolidation on 30 June 2016, Energex and Ergon Energy have become related parties and will be required to make associated related party disclosures for future RIN reporting. Given this relationship only commenced on 30 June 2016, no related party disclosures have been included in the 2015/16 RIN.
- Consistent with the definition provided in the CA RIN, Powerlink has not been included as related parties.

24.3.2 Approach

- Energex categorised the relevant information from Ellipse system as required in the Input Tables. The transactions with related parties were categorised into the CA RIN categories (emergency response, replacement, augmentation, etc.) based on their general ledger activity codes. Further classification into sub-categories for the relevant items was conducted by reviewing the nature and purpose of the transactions.

24.4 Estimated Information

No Estimated Information was reported.

24.4.1 Justification for Estimated Information

Not applicable.

24.4.2 Basis for Estimated Information

Not applicable.

24.5 Explanatory notes

Not applicable.

25. BoP 4.1.1- Public Lighting Descriptor Metrics Over Current Year

The AER requires Energex to provide the following information relating to RIN Table 4.1.1:

- **The current population of lights, by light type**

Actual Information was provided for all variables in RIN Table 4.1.1.

These variables are a part of Regulatory Template 4.1 – Public Lighting.

25.1 Consistency with CA RIN Requirements

Table 25.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 25.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for public lighting services reconcile to internal planning models used in generating Energex's proposed revenue requirements.	As advised by the AER in the CA RIN Issues Register (item 74), this requirement does not apply to DNSPs that are not completing reset RINs
Energex is not required to distinguish expenditure for public lighting services between standard or alternative control services in Regulatory Template 4.1.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).
Energex is not required to distinguish expenditure for public lighting services as either capex or opex in Regulatory Template 4.1.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).
Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).
Energex must report data for non-contestable, regulated public lighting services. This includes work performed by third parties	This requirement has been taken into account in preparing

Requirements (instructions and definitions)	Consistency with requirements
on behalf of Energex.	Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).
Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).
Energex is not required to report data in respect of GSLs, where a GSL scheme does not exist for a public lighting service.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).
In the basis of preparation, Energex must explain how the average unit cost for public lighting services was estimated.	This requirement has been taken into addressed in preparing Regulatory Template 4.1. For details please refer to section 25.31.2 (Methodology).

25.2 Sources

Table 25.2 sets out the sources from which Energex obtained the required information.

Table 25.2: Information sources

Variable	Source
The current population of lights, by light type	Peace / Oracle/NFM/SLIM

25.3 Methodology

25.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

There are three categories of public lights in Energex's network:

- Rate 1 – Public Lighting supplied, installed, owned and maintained by Energex;
- Rate 2 - Public Lighting for which all supply and installation costs are funded by the Developer or Public Body and then ownership is vested to Energex on completion of the installation. Or where design and construction services are requested to be

undertaken by Energex, the supply and installation costs are funded by the Public Body and the lighting installation is supplied, installed, owned and maintained by Energex. In both cases, Energex assumes responsibility for maintenance of the installation; and

- Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body.

Clause 17.6 of the CA RIN states that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER. For the purposes of Regulatory Template 4.1:

- Energex included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.

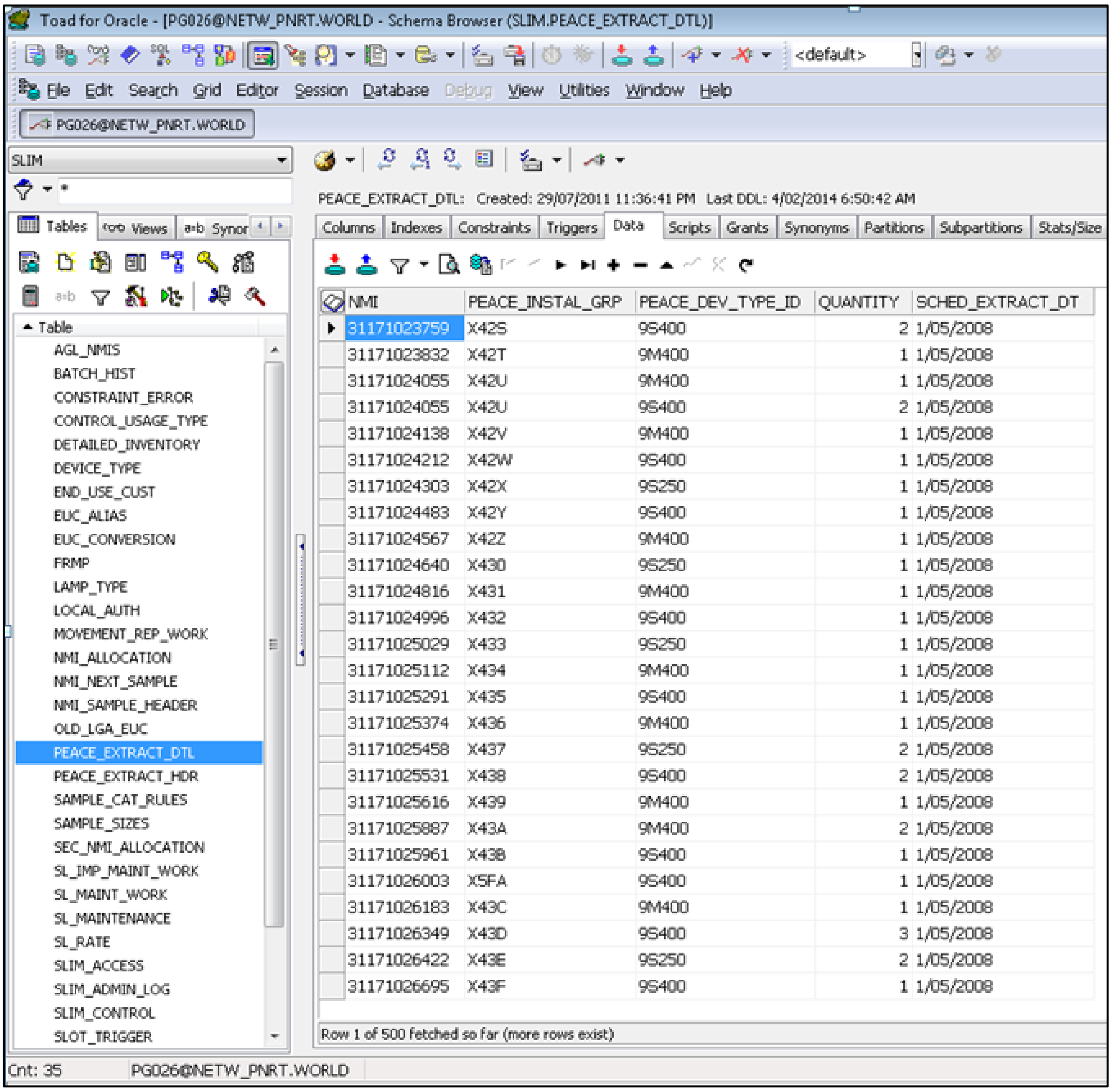
- Energex included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.

- All Rate 3 public lights have been excluded on the basis that they are supplied, installed, owned and maintained by the Public Body.

25.3.2 Approach

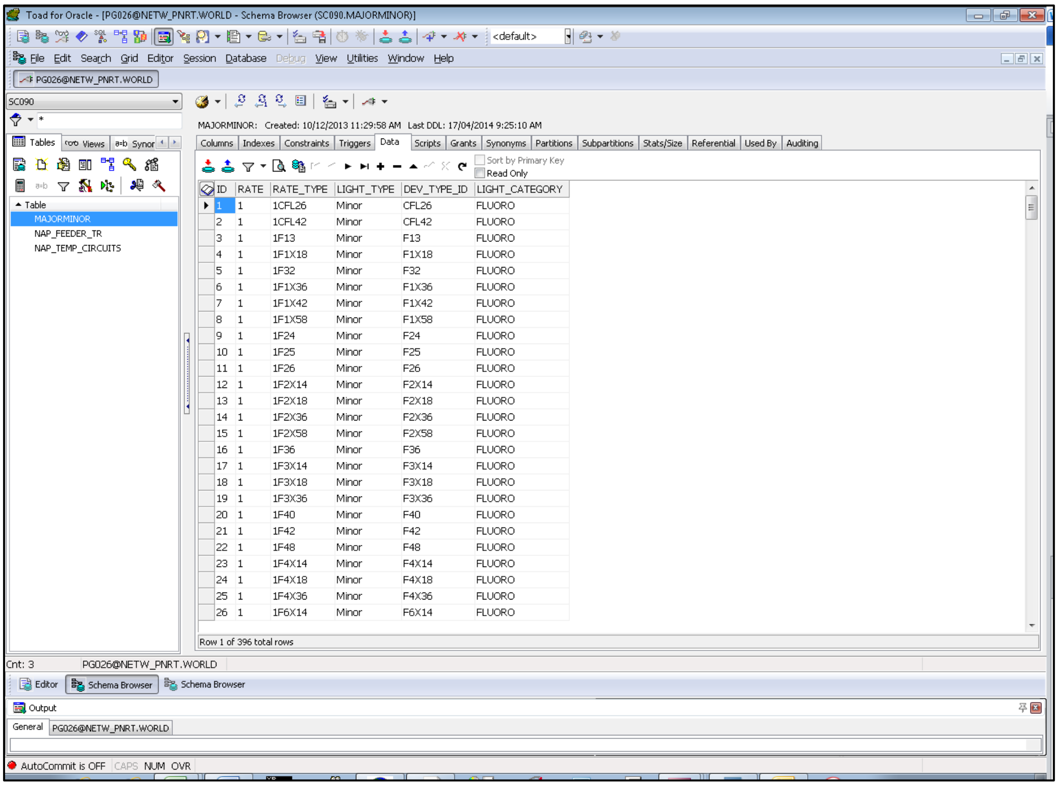
A report was extracted from both the SLIM database and the Oracle database to generate all the data required.

- SLIM.PEACE_EXTRACT-DTL is a SLIM (Streetlight Inventory Manager) table, located in the SLIM schema, containing light types and numbers for all the streetlight NMI's billed through the Peace billing system. The table provides a snapshot of the number of lights held in NFM and SLIM at the 1st day of each month. Streetlight NMI's are billed monthly and the numbers captured in this table are indicative of the number of lights to be billed as at the end of the previous month. A screenshot of the report is provided below.



NMI	PEACE_INSTAL_GRP	PEACE_DEV_TYPE_ID	QUANTITY	SCHED_EXTRACT_DT
31171023759	X42S	9S400	2	1/05/2008
31171023832	X42T	9M400	1	1/05/2008
31171024055	X42U	9M400	1	1/05/2008
31171024055	X42U	9S400	2	1/05/2008
31171024138	X42V	9M400	1	1/05/2008
31171024212	X42W	9S400	1	1/05/2008
31171024303	X42X	9S250	1	1/05/2008
31171024483	X42Y	9S400	1	1/05/2008
31171024567	X42Z	9M400	1	1/05/2008
31171024640	X430	9S250	1	1/05/2008
31171024816	X431	9M400	1	1/05/2008
31171024996	X432	9S400	1	1/05/2008
31171025029	X433	9S250	1	1/05/2008
31171025112	X434	9M400	1	1/05/2008
31171025291	X435	9S400	1	1/05/2008
31171025374	X436	9M400	1	1/05/2008
31171025458	X437	9S250	2	1/05/2008
31171025531	X438	9S400	2	1/05/2008
31171025616	X439	9M400	1	1/05/2008
31171025887	X43A	9M400	2	1/05/2008
31171025961	X43B	9S400	1	1/05/2008
31171026003	X5FA	9S400	1	1/05/2008
31171026183	X43C	9M400	1	1/05/2008
31171026349	X43D	9S400	3	1/05/2008
31171026422	X43E	9S250	2	1/05/2008
31171026695	X43F	9S400	1	1/05/2008

- SC090.MAJORMINOR is a local table created to identify what constitutes a Major or Minor type of light. The data in this table is in accordance with Australian Standard AS/NZ 1158. A screenshot of the report is provided below.



- These two tables were then joined in the TOAD SQL – RIN – 4.1.1 Rate 1.sql to provide the volume of Rate 1 streetlights broken down by streetlight category and by Major and Minor categories for the year 2015/2016.

25.4 Estimated Information

No Estimated Information was reported.

25.4.3 Justification for Estimated Information

Not applicable.

25.4.4 Basis for Estimated Information

Not applicable.

26. BoP 4.1.2- Public Lighting Descriptor Metrics Annually

The AER requires Energex to provide the following information relating to RIN Table 4.1.2:

For the 2015/16 regulatory year:

- **The volume of major road lights installed, replaced and maintained**
- **The volume of minor roads lights installed, replaced and maintained**
- **The number of poles installed, replaced and maintained**
- **The total cost of lights installed, replaced and maintained**
- **The mean days to rectify / replace public lighting assets**
- **The volume of GSL breaches**
- **The value GSL payments**
- **The volume of customer complaints**

All information is Actual Information.

These variables are a part of Regulatory Template 4.1 – Public Lighting.

26.1 Consistency with CA RIN Requirements

Table 26.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 26.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for public lighting services reconcile to internal planning models used in generating Energex's proposed revenue requirements.	As advised by the AER in the CA RIN Issues Register (item 74), this requirement does not apply to DNSPs that are not completing reset RINs
Energex is not required to distinguish expenditure for public lighting services between standard or alternative control services in Regulatory Template 4.1.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).
Energex is not required to distinguish expenditure for public lighting services as either capex or opex in Regulatory Template 4.1.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).
Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).

Requirements (instructions and definitions)	Consistency with requirements
Energex must report data for non-contestable, regulated public lighting services. This includes work performed by third parties on behalf of Energex.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).
Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).
Energex is not required to report data in respect of GSLs, where a GSL scheme does not exist for a public lighting service.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).
In the basis of preparation, Energex must explain how the average unit cost for public lighting services was estimated.	This requirement was taken into addressed in preparing Regulatory Template 4.1. For details refer to section 26.3 (Methodology).

26.2 Sources

Table 26.2 sets out the sources from which Energex obtained the required information.

Table 26.2: Information sources

Variable	Source
The volume of major road lights installed, replaced and maintained	NFM, SLIM, Oracle, Intrinsic Energy Database
The volume of minor roads lights installed, replaced and maintained	NFM, SLIM, Oracle, Intrinsic Energy Database
The number of poles installed, replaced and maintained	NFM, Ellipse, Intrinsic Energy Database
The total cost of lights installed, replaced and maintained	EPM, Ellipse
The mean days to rectify / replace public lighting assets	Intrinsic Energy Database
The volume of GSL breaches	N/A
The value GSL payments	N/A
The volume of customer complaints	EPM, Cherwell

26.3 Methodology

26.3.1 Assumptions

General assumptions

1) There are three categories of public lights in Energex's network:
   a. Rate 1 – Public Lighting supplied, installed, owned and maintained by Energex;
   b. Rate 2 - Public Lighting for which all supply and installation costs are funded by the Developer or Public Body and then ownership is vested to Energex on completion of the installation. Or where design and construction services are requested to be undertaken by Energex, the supply and installation costs are funded by the Public Body and the lighting installation is supplied, installed, owned and maintained by Energex. In both cases, Energex assumes responsibility for maintenance of the installation; and
   c. Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body.
2) Clause 17.6 of the CA RIN states that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER. For the purposes of Regulatory Template 4.1:
   – Energex has included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.
   – Energex has included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.
   – All Rate 3 public lights have been excluded on the basis that they are supplied, installed, owned and maintained by the Public Body.

Number of poles installed

1) It was assumed that any light installed on a wood pole bracket did not involve installation of a dedicated street light pole as this would be a very small population of poles and the figures are not discernible from other wood poles in Energex's asset records.

Customer Complaints

1) Complaints categorised as 'street lighting' relate to customer dissatisfaction with the establishment or maintenance of street lighting (I.e. pole placement, lights not working or brightness of lights).

26.3.2 Approach

Major and minor road light installation volume

1) To obtain volumes for installations, an SQL query was run through Oracle, utilising various tables from the NFM and SLIM schemas. The query returned the following attributes, based on a 'Movement Status' of added lights (a proxy for installations):
   a. Date;
   b. Works Order Number;
   c. User Ref Id (site ID);
   d. Slot_Sun (unique record attached to each streetlight slot);
   e. Light Type;
   f. Light Rating;
   g. Major/Minor status; and
   h. Light Category.
2) This query returned all Rate 1 and Rate 2 public lights installed in 2015/16.
3) As noted earlier, gifted public lights are excluded from Regulatory Template 4.1. Gifted public lights were identified as Rate 2 projects approved through Energex's Subdivisions group. These projects were identified as those which had an 'S' qualifier at the beginning of the work order number. These were excluded from the query.
4) The process was run for the 2015/16 financial year and the dataset was copied to a spreadsheet and a pivot table was created, filtering the results into Major and Minor light installations.
5) The total volume of public lighting installed was established by summing the number of public lights for Major and Minor.

Number of poles installed

1) Using the Major/Minor installation figures calculated previously, another query was created to identify the number of street light poles installed. Using the SITE_SUN (unique identifier for a site) set against each of the lights, the pole installation details were extracted. Results were returned where the pole was identified as Steel and the Install date of the pole matched the install date of the light. Duplicate values were removed to ensure only one pole record per site was returned. This was necessary as there are instances where more than one light has been installed on one pole.
2) It was assumed that any light installed on a wood pole did not involve installation of a dedicated street light pole, as this would be a very small population of poles and the figures are not discernible from other wood poles in Energex's asset records. All

new street light installations on steel brackets were assumed to require a new steel pole to be installed.

Total Installation cost

1) For 2015/16 the list of projects that incurred expenditure was taken from the EPM Report FIN077. The list of projects included is based on the below:

Activity Code	Description
C3560	Street Lighting
C3561	Street Lighting (new installs)
C3562	Street Lighting (replacement projects)

2) These reports detailed all expenses and quantities booked against street lighting projects (both installations and replacements) in the 2015/16 regulatory year.

3) From this data set, a number of adjustments were made to exclude gifted assets and items relating to streetlight mains recovery projects.

4) Gifted assets were excluded in accordance with clause 17.6 of the CA RIN by removing projects with any transaction in expense code 6270 (Capital Contributions Non-Cash Expenses).

5) Street lighting mains recovery projects were excluded from the data set on the basis that this work is the recovery of assets. Expense line items relating to street lighting mains recovery projects were identified by project description and removed from the data set.

6) Cost data from each expense line item was then aggregated to provide the total cost of street lighting projects for each financial year.

7) For 2015/16 two new financial activities, C3561 and C3562 were created to capture installations and replacements separately. A legacy issue exists for superseded financial activity code C3560, specifically for work orders created under this code prior to creation of C3561 & C3562 and booked post 30-Jun-2015. These costs were further analysed to determine if NAMP SL04 was associated with the Top Project number. It was found all transactions in financial activity C3560 had an association NAMP SL04, and as such have been reported as replacement projects along with all bookings to C3562.

8) Consequently, all expenditure is reported as actual.

Major and minor road light replacement volume

Projects relating to public light replacements are not explicitly identified in NFM. In most cases, where a streetlight was replaced, the event log in NFM will show a ‘Removal’ and an

‘Install’. However, this information alone does not provide a true indication of street light replacements.

The approach adopted by Energex to extract actuals for light replacements involves obtaining data from two data sources:

1) The Streetlight Head Replacement report received from Energex’s current maintenance contractor – Intrinsic Energy. This is received as an Excel spreadsheet on a monthly basis, and includes details of all lights replaced following identification of having failed in service and assessed an uneconomical to maintain/repair.

2) The SLIM movement report listing all streetlight head changes however only where the light is changed from one light type to another. A variety of filters are applied to enable identification of lights replaced in addition to those by other than Intrinsic Energy.

Specifically, the process involved the following steps:

1) The Streetlight Head Replacement report from Intrinsic Energy lists all sites, light types, dates where a head change was made. A pivot table applied to this report returns the major and minor replacement data.

2) The SLIM movement reports are run for each LGA for the determined period and combined on one spreadsheet.

    a. The additions and removal records are deleted.

    b. Rate 3 sites (customer owned and maintained) are deleted.

    c. All changes identified as being carried out by Intrinsic Energy are also deleted. This is done by sorting by work order number and removing the records identified as issued to Intrinsic Energy .

    d. A lookup table is used to distinguish between the major and minor type lights.

    e. A pivot table is applied to obtain the major and minor replacement values.

3) The data from both spreadsheet pivot tables are added together.

Number of poles replaced

1) The volume of poles replaced was obtained by extracting data for actual pole replacement works undertaken under projects for NAMP line SL04 (or equivalent project code).

Total Replacement cost

1) For 2015/16 two new financial activities, C3561 and C3562 were created to capture installations and replacements separately. A legacy issue exists for superseded financial activity code C3560, specifically for work orders created under this code prior to creation of C3561 & C3562 and booked post 30-Jun-2015. These costs were further analysed to determine if NAMP SL04 was associated with the Top Project number. It was found all transactions in financial activity C3560 had an association NAMP SL04, and as such have been reported as replacement projects along with all bookings to C3562.

Major and minor road light maintenance volume

1) The light maintenance volumes represent the actual number of luminaires maintained as part of the street light maintenance contract. This contract constitutes the bulk of the maintenance work on lights in the Energex network, with lighting maintenance undertaken by internal staff only for the remote towns of Boonah, Gatton & Esk.

2) The data for actual number of lights maintained is extracted from Streetlighting maintenance contractor Intrinsic Energy monthly Activity Report. The maintenance data is captured at site in conjunction with the completion each activity utilizing the contractors electronic work dispatching/updating device. This data is then uploaded into their database and utilized for reporting and billing purposes.

3) It is important to note that activities relating to the maintenance of gifted assets were not excluded from the data as these assets could not be identified in the maintenance contract data. This is due to streetlighting maintenance activities (patrols and subsequent maintenance) being undertaken uniformly across all public lighting assets owned by Energex. Whether the capital cost of installation was funded by Energex or others is not a consideration when undertaking maintenance activities.

Number of poles maintained

1) The number of poles maintained includes steel streetlighting standards that were found to have defects and were subsequently rectified by Energex's Streetlighting maintenance contractor Intrinsic Energy. Data source is a excel spreadsheet supplied by the contractor, prepared from their daily activity reports.

2) Any streetlight pole maintenance undertaken under Energex's pole maintenance contract cannot be distinguished from distribution poles, and as such is not included.

Total Maintenance Cost

1) A report FIN077 was run from EPM which listed all street lighting projects that formed part of the maintenance works in 2015/16 under the financial activity code 41600 (street lighting).

2) This report detailed all expenses and quantities booked against street lighting maintenance projects in 2015/16. Cost data from each expense line item was then aggregated to provide the total maintenance cost of street lighting projects. It is important to note that costs relating to maintenance of gifted assets were not excluded from the cost data as these assets could not be identified in the EPM report.

Mean days to rectify / replace assets

The mean days to repair is calculated from data supplied by Energex's streetlighting contractor Intrinsic Energy, collated from their daily activities reporting. The calculation is undertaken in a spreadsheet which lists all identified streetlight faults, the days the fault was identified, and the day the fault was rectified. The mean days to repairs is then calculated as the mean working days to rectify of the total data set for 2015-16,

Note: The following faults are excluded from the calculation:

- On by day streetlights (i.e. operating continuously) are excluded from this data as this is a low priority fault with a longer timeframe for repair when compared to off by night streetlight faults.
- Faults requiring roadway access permits as these are subject to delays imposed by the issuing authority.
- Underground circuit faults as these are often complex and time consuming to identify the fault following the identification of the light not operating.

Volume of customer complaints

1) Complaint data is derived from a feedback report in EPM (CUS011 – Feedback Detail) which extracts information from Energex's Cherwell system and encompasses all complaints received to Energex (that is, via phone, letter or email). The report details the date the complaint was received and is categorised by the Customer Relations team using the systems feedback structure.

2) A financial year report was sourced from EPM filtered to show the complaints categorised as "street lighting". The total volume of complaints relating to street lighting was established by summing the number of complaints in this category.

26.4 Estimated Information

No figures are estimated.

26.4.3 Justification for Estimated Information

Not applicable.

26.4.4 Basis for Estimated Information

Not applicable.

26.5 Explanatory notes

Not applicable.

27. BoP 4.1.3 - Public Lighting Cost Metrics

The AER requires Energex to provide the following information, for the 2015/16 regulatory year, relating to RIN Table 4.1.3:

The average unit cost of each light type:

- **Installed on major and minor roads**
- **Replaced on major and minor roads**
- **Maintained on major and minor roads**

Values for average unit cost of installation, replacement and maintenance are Actual Information.

These variables are a part of Regulatory Template 4.1 – Public Lighting.

27.1 Consistency with CA RIN Requirements

Table 27.1 demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 27.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for public lighting services reconcile to internal planning models used in generating Energex's proposed revenue requirements.	As advised by the AER in the CA RIN Issues Register (item 74), this requirement does not apply to DNSPs that are not completing reset RINs
Energex is not required to distinguish expenditure for public lighting services between standard or alternative control services in Regulatory Template 4.1.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).
Energex is not required to distinguish expenditure for public lighting services as either capex or opex in Regulatory Template 4.1.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).
Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).
Energex must report data for non-contestable, regulated public	This requirement was taken into

Requirements (instructions and definitions)	Consistency with requirements
lighting services. This includes work performed by third parties on behalf of Energex.	account in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).
Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER.	This requirement was taken into account in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).
Energex is not required to report data in respect of GSLs, where a GSL scheme does not exist for a public lighting service.	This requirement has been taken into account in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).
In the basis of preparation, Energex must explain how the average unit cost for public lighting services was estimated.	This requirement has been taken into addressed in preparing Regulatory Template 4.1. For details refer to section 27.3 (Methodology).

27.2 Sources

Table 27.2 sets out the sources from which Energex obtained the required information.

Table 27.2: Information sources

Variable	Source
The average unit cost of lights installed on major and minor roads	Ellipse estimation module
The average unit cost of lights replaced on major and minor roads	Ellipse estimation module
The average unit cost of lights maintained on major and minor roads	Ellipse, SLIM/NFM.

27.3 Methodology

27.3.1 Assumptions

General assumptions

1) There are three categories of public lights in Energex's network:
    a. Rate 1 – Public Lighting supplied, installed, owned and maintained by Energex;
    b. Rate 2 - Public Lighting for which all supply and installation costs are funded by the Developer or Public Body and then ownership is vested to Energex on completion of the installation. Or where design and construction services are

requested to be undertaken by Energex, the supply and installation costs are funded by the Public Body and the lighting installation is supplied, installed, owned and maintained by Energex. In both cases, Energex assumes responsibility for maintenance of the installation; and

c. Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body.

2) Clause 17.6 of the CA RIN states that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER. For the purposes of Regulatory Template 4.1:

a. Energex has included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.

b. Energex has included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.

c. All Rate 3 public lights have been excluded on the basis that they are supplied, installed, owned and maintained by the Public Body.

3) The average unit costs have in the past been reported as estimated cost, based upon standard estimates to match the “light type” installation styles listed. To capture a true average cost per light type established would involve large scale changes to capital project structures, project estimation practices and work order booking practices by field staff, accompanied by a complex definition to determine what components are to be included in contributing to the average cost. This is particularly problematic where installations are undertaken in conjunction with distribution network works, which is common. Therefore, the ‘Average Unit Cost of Installation’ and ‘Average Unit Cost of Replacement’ data will continue to be determined through the use of standard estimates and their accompanying definitions detailed below, and are now reported as an actual average unit cost.

Average unit cost of installation

1) Variations in the installation costs of differing lamp types are negligible in comparison with the average installation cost of Energex’s standard street light constructions. On this basis, the information provided in Table 4.1.3 is based on Energex’s estimated cost of standard street light constructions, which are lamp type agnostic. At present, Energex has 5 types of standard constructions for public lighting, namely:

a. Wood Pole Major – the estimated unit cost assumes the wood pole exists and low voltage supply is available (i.e., average unit cost data does not include the cost of installing a pole or provision of supply);

b. Steel Overhead Major – the estimated unit cost includes installation of a new steel pole and provision of a 40 metre span of overhead service;

c. Underground Major – the estimated unit cost includes installation of a new steel pole and provision of a 30 metre length of underground supply;

d. Wood Pole Minor – the estimated unit cost assumes the wood pole exists and low voltage supply is available (i.e., average unit cost data does not include the cost of installing a wood pole or provision of supply); and

e. Steel Underground Decorative Minor– the estimated unit cost includes the installation of a new decorative steel pole and provision of a 5 metre length of underground supply.

2) All costs for the street light constructions above were estimated at 2015/16 cost rates.

Average unit cost of replacement

1) The light types provided in Table 4.1.3 for replacements represent the standard luminaires during the period. These include the following:

   a. High Pressure Sodium Major 150W;

   b. Compact Fluorescent 32W; and

   c. High Pressure Sodium Minor 70W.

2) The differential in luminaire costs for different sizes of the same type of luminaire (e.g. High Pressure Sodium 150W and High Pressure Sodium 250W) was assessed as negligible.

3) Significantly more expensive Pedestrian Crossing, High Mast and Bulkhead and Decorative luminaire types have not been considered due to their relatively low volumes in comparison with the standard luminaires.

4) The average unit cost data included the estimated cost of supply and replacement of a luminaire, lamp and photoelectric cell.

Average unit cost of maintenance

1) Maintenance on the street light network only distinguishes by categories of mounting height, not by light type and size. On this basis, Energex has reported the average unit cost of maintenance combined for both major road and minor road lights.

2) The maintenance costs included to determine the average unit cost includes the following actuals costs:

   a. Actual cost for luminaire maintenance;

   b. Actual Streetlight circuit maintenance costs.

   c. Actual Streetlight patrol costs

   d. Actual material cost, and

   e. Actual proximity testing costs.

3) It is important to note that activities relating to the maintenance of gifted assets were not excluded from the data as these assets could not be identified in the maintenance contract data. This is due to streetlighting maintenance activities (patrols and subsequent maintenance) being undertaken uniformly across all public lighting assets owned by Energex. Whether the capital cost of installation was funded by Energex or others is not a consideration when undertaking maintenance activities.

27.3.2 Approach

Average unit cost of installation

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

1) Wood Pole Major – as described above, the estimated unit cost assumes the wood pole exists and low voltage supply is available. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92431 (version 9).

2) Steel Overhead Major – as described above, the estimated unit cost includes installation of a new steel pole and provision of a 40 metre span of overhead service. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92434 (version 10).

3) Underground Major – as described above, the estimated unit cost includes installation of a new steel pole and provision of a 30 metre length of underground supply. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92435 (version 8).

4) Wood Pole Minor – as described above, the estimated unit cost assumes the wood pole exists and low voltage supply is available. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92430 (version 11).

5) Steel Underground Decorative Minor– as described above, the estimated unit cost includes the installation of a new decorative steel pole and provision of a 5 metre length of underground supply. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92433 (version 11).

Average unit cost of replacement

The average unit cost of street light replacements was prepared for the 3 types of luminaires (as identified in the assumptions section above). The methods for calculating the estimated unit costs are outlined below:

1) High Pressure Sodium Major 150W – the estimated unit cost includes the supply and replacement of a luminaire, lamp and photoelectric cell. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424075 (version 4).

2) Compact Fluorescent 32W – For the 2015/16 period, the estimated unit cost includes the supply and replacement of a 32W Compact Fluorescent (CFL) luminaire, lamp and photoelectric cell. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424068 (version 4).

3) High Pressure Sodium Minor 70W – the estimated unit cost includes the supply and replacement of a luminaire, lamp and photoelectric cell. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424071 (version 4).

Average unit cost of maintenance

1) The overall total maintenance cost is comprised from the following:
    a) Actual cost for luminaire maintenance;
    b) Actual Streetlight circuit maintenance costs;
    c) Actual Streetlight patrol costs;
    d) Actual Proximity testing costs;
    e) Actual material costs.

    These costs are extracted from the following expenditure reports:

    - Energex's streetlight maintenance contract, refer Report Explorer report ELL00161 – Contract Monthly Spend APL for luminaire maintenance and circuit maintenance.
    - Proximity testing and Patrol costs were sourced direct from the Streetlighting maintenance contractor Intrinsic Energy's monthly activity reports. The maintenance data is captured in conjunction with the completion each activity utilizing the contractors electronic work dispatching/updating device. This data is then uploaded into their database and utilized for reporting and billing purposes.

- Materials costs are extracted from expenditure reports from Ellipse Materials Management module, refer Report Explorer report ELL00159 – Works Oder transactions.

2) Calculation of the average unit cost for streetlight maintenance is undertaken by dividing the actual total maintenance cost into the total population of Rate 1 and Rate 2 street lights at the end of the financial year. This population is extracted from SLIM/NFM per the process detailed in EB RIN Basis of Preparation 3.5.8.

27.4 Estimated Information

No Estimated Information was reported.

27.4.1 Justification for Estimated Information

Not applicable.

27.4.2 Basis for Estimated Information

Not applicable.

27.5 Explanatory notes

There are a number of variables that can affect the average unit cost of maintenance:

- Heavy storm activity in a particular year;
- Catastrophic weather events e.g. floods which have an ongoing affect, causing failures for many months afterwards;
- Premature failure of components e.g. batches of faulty PE cells; and
- Life cycle failures of components e.g. 5 year life cycle of certain lamps.

This is just sample of some of the variables that may occur or be absent that can cause variation year to year.

28. BoP 4.2.1- Metering

The AER requires Energex to provide the following information for the 2015/16 regulatory year, in Table 4.2.1 – Metering Descriptor Metrics:

Split by meter installation type (i.e. type 4, 5 or 6):

- **Single phase meter population**
- **Multi-phase meter population**
- **Current transformer connected meter population**
- **Direct connect meter population**

The AER requires Energex to provide the following information for the 2015/16 regulatory year, in Table 4.2.2 – Cost Metrics for meter types 4, 5 and 6:

- **Expenditure cost for the service subcategories defined by the AER**
- **Volumes of in-service meters for the service subcategories defined by the AER, split by meter installation type (i.e. type 4, 5 or 6).**

Actual information was provided for:

RIN Table 4.2.1

- **All figures**

RIN Table 4.2.2

- **All figures**

28.1 Consistency with Category Analysis RIN Requirements

Table 28.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 28.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for metering services reconciles to internal planning models used in generating Energex's proposed revenue requirements.	Figures reconcile to internal planning models where appropriate.
Energex is not required to distinguish expenditure for metering services between standard or alternative control services in Regulatory Template 4.2.	No distinction has been made between SCS and ACS.
Energex is not required to distinguish expenditure for metering services as either *capex* or *opex* in Regulatory Template 4.2	No distinction has been made between capex and opex.
Energex must report data for non-contestable, regulated	All information supplied is specific to

Requirements (instructions and definitions)	Consistency with requirements
metering services. This includes work performed by third parties on behalf of Energex.	the regulated business including third party labour values as captured via the general ledger in Ellipse.
Energex must not report data in relation to *metering services* which have been classified as contestable by the AER.	Whilst preparing this information, strict measures were taken not to include any information relating to Contestable Metering Servicers.
Energex must only report on regulated metering services as defined in the AER document and National Electricity Rules and Metrology Procedures	Only regulated metering services and assets as defined have been included in RIN Tables 4.2.1 and 4.2.2.
Actual Information presented in response to the Notice whose presentation is Materially dependent on information recorded in Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.	Actual volumes and expenditure have been used in compiling this data.
Estimated Information presented in response to the Notice whose presentation is not Materially dependent on information recorded in Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.	Actual volumes and expenditure have been used in compiling this data.
The CA RIN explanatory statement included the following instruction in relation to table 4.2.1: We expect meter numbers to be calculated as the average meter numbers per annum. That is, closing balance of meter numbers plus opening balance of meter numbers, divided by two.	Energex has applied this instruction when completing table 4.2.1 of the Category Analysis RIN and meter numbers have been calculated as the average during the financial year.

28.2 Sources

Table 28.2 below sets out the sources from which Energex obtained the required information.

Table 28.2: Information sources

Variable	Source
RIN Table 4.2.1 – Meter Populations	DMA RIN Configuration Solution (CA42101a – Meter Population).
RIN Table 4.2.2 – Cost Metrics Expenditure	Ellipse, EPM Report PUR012,
RIN Table 4.2.2 – Cost Metrics Volume	Ellipse, EPM Reports: PUR012, CUS015 & POW015, PEACE reports MSR297 & Meter_Events Report.

28.3 Methodology

28.3.1 Assumptions

The following assumptions have been applied to obtain the required information:

- Energex does not have type 4 or type 5 meters in its regulated business and as such no information has been reported against these variables.
- All expenditure excludes General Overheads.

28.3.2 Approach

The following approach below was used to obtain the required information:

Table 4.2.1 – Meter Populations

- Meter population figures were obtained from the DMA RIN Configuration Solution (CA42101a – Meter Population). It is a metric value based on a financial year prompt summated to the CA RIN grain and will deliver the required information and enable submission of meter volumes where installation type is '6' and status is '2' (In-service) thus providing greater understanding of in-service regulated (Type 6) meter population.
  The data contained within the report is sourced from MARS_ME schema in order to determine overall meter quantities with installation type (type 6) confirmed through the use of PEACE data. As data is high level counts with no detail, there will not be any security required and all NMIs meeting the AER requirements will be included for all report users.
  Each meter is defined by the model to identify which should be included in the poly phase, single phase, CT connected and DC connected categories. The logic to differentiate type 6 meter installation types from 1-4 was where the meter model <> "VM01" or "SM01" (VM01 = virtual meter, SM01 means unmetered site, everything else is type 6). To differentiate between connection type, DC or CT, where the meter that has been selected as type 6 has got a correction factor > 1, meter type is CT, otherwise if it = 1, it is DC. If null, it's a data error.

Data quality is such that accuracy is above 97% with unknown asset data being aligned to assets that are located within restricted sites (prisons, fire brigades, asbestos sites, hospitals, industrial). As the unknown data equates to a negligible portion of assets it is disregarded - therefore no estimation is required.

Filters:
1. Installation Type=6
2. Meters in service =Yes
3. Date = 1 July of selected financial year and 30 June of selected year

Grouping Rules:
Meter Model
Meter Phase
- Single
- Poly
CT_DC Type
- Current Transformer
- Direct Connect

- There is an overlap of the volume between single phase volume and CT connected volume to meter installation types.

- All metering numbers have been calculated as the average within the financial year. This is the number of meters as at 1 July 2015 plus the number as at 30 June 2016 divided by two for each respective year.

Table 4.2.2 – Meter Purchase expenditure and volume

- A report was extracted from EPM Business Objects report PUR012 using the Regulated Metering Stock Codes. Refurbished meter volumes and expenditure figures were manually extracted from Ellipse application MSO178. The following stock codes were included in the Meter Purchases category for both expenditure and volumes:
  - 10334 - PRI REGN,KWH;3 X 10/125 AMP,3 X 240 V; 3 PH,4 WIRE;S/RATE;WITH OUTPUT PULSE;
  - 17723 - PRI REGN KWH;3 X 10-100/125 AMP, 3 X 240 V,50 HZ;3 PHASE,4 WIRE,SOLID STATE PROGRAMMABLE;
  - 17724 - PRI REGN KWH;3 X 10-100/125 AMP, 3 X 240 V,50 HZ;3 PHASE;4 WIRE,SOLID STATE PROGRAMMABLE;
  - 19681 - 240 V,50 HZ;15-100 AMP;2 SINGLE PHASE ELEMENTS;2 X 40 AMP OUTPUT RELAYS;
  - 19692 - 240 V,15 100 AMP;SINGLE PHASE;LOAD PROFILING RS232 TERMINALS;12 PER;
  - 21266 - PRI REGN;KWH;3 X 10-100 AMP,3 X 240 V; 3 PHASE;4 WIRE;S/RATE;FOR SOLAR PV;

- 21388 - PRI REGN;KWH;10-100 AMP;240 V,SINGLE PHASE;LOAD PROFILE,RS232;PLUG-IN;
- 22441 - METER,WATTHOUR. 240 V,10-100 AMP;SINGLE PHASE;1 ELEMENT; CLASS 1.0 WC;3.6 W;INTERNAL MODEM POWER;
- 23916 - LANDIS + GYR U1325 METER; SINGLE PHASE METER 2 ELEMENT WITH RIPPLE CONTROL & 1 LOAD CONTROL RELAY
- 22081 - 240 V;10-100 AMP;SINGLE PHASE;2 ELEMENT; SMART METER;CLASS1.0;3.6 W INTERNAL MODEM POWER SUPPLY;C/W RJ45/RS232 LEAD;1 X 12 V IN;3 X S0 OUT
- 24699 - MK10D, 180-290V, 10-100A; POLY PHASE; CLASS 1.0 DC; 3P4W

- The figures provided are actual information in quantity and expenditure.

Table 4.2.2 – Meter Testing expenditure and volume

- Only Network driven ACS Meter Testing expenditure and volumes are included in these figures as per the AER definition. Expenditure is actual and has been extracted from EPM using FIN077 report and expenditure under cost centre 42500 P086 (Meter Test Program) and expenditure under P087 (CT Metering) relating to CT testing.
- Volumes were taken from EPM using report POW015 (Physicals summary) and quantities against NAMP lines SC13 (In Service Meter Compliance), SC15 (Compliance Testing of CT's) and SC16 (Compliance Testing of CT Meters).

Table 4.2.2 – Meter Investigation expenditure and volume

- Network driven expenditure was extracted from EPM using report FIN077 under cost centre 42500 P081 relating to Meter Investigation expenditure. Work orders containing the following descriptions were included in expenditure:
  - De-en RPU link Com
  - De-en RPU MSS Com
  - Disconnect for Defects 31 Complete
  - Loss of Supply/Cold Water complaints
  - Meter Query
  - Revenue Protection

  Customer Requested expenditure was extracted from EPM using report FIN077 under cost centre 42500 P070 Meter Investigation.
- The volumes are the completed Meter Investigation service orders from the CUS015 report (Service Delivery Compliance) in EPM less the volume of

replacements that occurred for these service orders using PEACE report Meters_Replacements.

Table 4.2.2 – Scheduled Meter Reads expenditure and volume

- The volumes and expenditure for scheduled meter reads are based on actual spend and quantity against Purchase order 426383 for cyclical meter reads.

Table 4.2.2 – Special Meter Reads expenditure and volume

- The volumes and expenditure for special meter reads are based on actual spend and quantity against Purchase order 426383 for special meter reads.

Table 4.2.2 – New Meter Installation expenditure and volume

- New Meter Installation expenditure is taken from the general ledger using Ellipse. Report FIN077 was run in EPM for the financial year 2015/16 on activity C3585 (Type 6 metering).
- The volumes are the completed Meter Installation service orders (New Installs, Exchange Meters, Adds & Alts) taken from Peace Billing Report MSR297.

Table 4.2.2 – Meter Replacement expenditure and volume

- This expenditure has been extracted from the general ledger using Ellipse. Report FIN077 was run in EPM for the financial year 2015/16 on activity C3586 (Meter Replacements).
- The volumes are taken from EPM for Planned Replacements (POW015) using NAMP line SC14 & volumes given by the Metering Compliance Specialist for the Power Quality program. The volumes for unplanned replacements are the meter maintenance and meter investigations service orders that result in a replacement and are taken from PEACE using the Meter_Replacements _report.

Table 4.2.2 – Meter Maintenance expenditure and volume

- Meter maintenance expenditure has been extracted from Ellipse. Report FIN077 was run in EPM for the financial year 2015/16 on cost centre 42500 P081 and sorted by work order description Work orders containing the following descriptions were included in expenditure:
  - A&A Remove Meter
  - Maintain Meter
  - Re-en Dummy
  - Reenergisation (after disconnect) comp
  - Repl Meter Seal

  FIN077 was also run in EPM for cost centre 42500 P066 (Move Meter).

- The volumes are the completed Meter Maintenance service orders using EPM report CSU015 (Service Delivery Compliance) less the volume of meter maintenance service orders that ended in a replacement occurring using PEACE report Meter_Replacements.

Table 4.2.2 – Remote Meter Reading expenditure and volume

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

Table 4.2.2 – Remote Meter Reconfiguration expenditure and volume

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

Table 4.2.2 – Other Metering expenditure

- The following has been included in “Other Metering Expenditure:
    - Current Transformer sales expenditure. The expenditure has been extracted from Ellipse via report FIN077 in EPM in cost centre 42500 P087 and sorted by the CT requests from stores work order.
    - Meter Data Services Expenditure. Expenditure has been extracted from Ellipse via report FIN077 in EPM in cost centre 43500 P084.
    - Customer Requested Meter Reconfiguration expenditure. Expenditure has been extracted from Ellipse via report FIN077 in EPM in cost centre 42500 P071.

Table 4.2.2 – IT Infrastructure Opex/Capex

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

Table 4.2.2 – Communications Infrastructure Opex/Capex

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

28.4 Estimated Information

There is no estimated information included in the 2015/2016 RIN.

28.4.2 Justification for Estimated Information

Not applicable

28.4.3 Basis for Estimated Information

Not applicable

29. BoP 4.3.1- Fee-Based Services

The AER requires Energex to provide the following information relating to Table 4.3.1 – Cost Metrics for Fee-Based Services:

- **Expenditure and volumes for all fee-based services listed in Energex's annual tariff proposal for the 2015/16 regulatory year**

All information provided is Actual Information.

These variables are a part of Regulatory Template 4.3 – Fee-Based Services.

29.1 Consistency with Category Analysis RIN Requirements

Table 29.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 29.1: Demonstration of Compliance

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

29.2 Sources

Table 29.2 below sets out the sources from which Energex obtained the required information.

Table 29.2: Information sources

Variable	Source
Expenditure dollar values for fee based services	General ledger reports
Volumes for fee based services	MSR246 Peace report

29.3 Methodology

29.3.1 Assumptions

Energex has consistently reported direct costs throughout other Regulatory Templates. This means that overhead costs have been excluded from the Fee-Based Services figures reported in Regulatory Templates 4.3

29.3.2 Approach

Energex applied the following approach to obtain the required information:

Services to be reported

- Energex's 2015 – 2020 Framework & Approach, Classification of Services, Pricing Proposal and Tariff Schedule were reviewed to determine which services should be classified as Fee-Based from 2015/16.
- Any customer-requested services which are charged via a fixed fee have been reported in Template 4.3 Fee-Based Services. This results in duplications between Template 4.3 Fee-Based Services and Templates 2.5 Connections, 4.1 Public Lighting and 4.2 Metering. These duplications have been identified as balancing items for Template 2.1 Expenditure Summary.

Expenditure Dollar Values

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

Volume

- Volumes for Fee-Based Services were obtained from the PEACE report MSR246. These volumes represent the number of services performed.

29.4 Estimated Information

No Estimated Information was reported.

29.4.1 Justification for Estimated Information

Not applicable.

29.4.2 Basis for Estimated Information

Not applicable.

29.5 Explanatory notes

Consistent with Energex's Pricing Proposal, from 2015/16, Fee-Based Services provided at any time (business hours, after hours or anytime) are reported as Fee-Based Services. This reflects a change from prior years when any after hours or anytime provision of Fee-Based Services were reported as Quoted Services.

30. BoP 4.4.1- Quoted Services

The AER requires Energex to provide the following information relating to Table 4.4.1 – Cost Metrics for Quoted Services:

- **Expenditure and volumes for all quoted services listed in Energex's annual tariff proposal for the 2015/16 regulatory year.**

Actual Information was provided for all variables.

These variables are a part of Regulatory Template 4.3 – Quoted Services.

30.1 Consistency with Category Analysis RIN Requirements

Table 30.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 30.1: Demonstration of Compliance

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

30.2 Sources

Table 30.2 below sets out the sources from which Energex obtained the required information.

Table 30.2: Information sources

Variable	Source
Expenditure dollar values for quoted services	General ledger reports
Volumes for quoted services	EPM Report – Quoted Services Volume & Revenue: 1306163

30.3 Methodology

30.3.1 Assumptions

Energex has consistently reported direct costs throughout other Regulatory Templates. This means that overhead costs have been excluded from the Quoted Services figures reported in Regulatory Template 4.4

30.3.2 Approach

Energex applied the following approach to obtain the required information:

Services to be reported

- Energex's 2015 – 2020 Framework & Approach, Classification of Services, Pricing Proposal and Tariff Schedule were reviewed to determine which services should be classified as Quoted from 2015/16.
- Any customer-requested services which are charged via a quoted price have been reported in Template 4.4 Quoted Services. This results in duplications between Template 4.4 Quoted Services and Templates 2.5 Connections and 4.1 Public Lighting. These duplications have been identified as balancing items for Template 2.1 Expenditure Summary.

Expenditure Dollar Values

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

Volume

- All volumes were obtained from the EPM Report – Quoted Services Volume & Revenue: 1306163 and

- These volumes represent the number of services completed in the financial year.

30.4 Estimated Information

No Estimated Information was reported.

30.4.1 Justification for Estimated Information

Not applicable.

30.4.2 Basis for Estimated Information

Not applicable.

30.5 Explanatory notes

Large customer connections

During the previous Determination period (2010 – 2015), Energex's accounting treatment for Large Customer Connections (LCC) was governed by the contracts with the customers. As such, while treated as ACS, the transactions were treated similar in nature to SCS capex projects that receive capital contributions. While the projects were treated as capex with expenditure recognised as incurred, they were not added to any regulatory asset base. Associated revenue is not recognised until the asset is fully constructed and energised.

New LCC projects from this Determination period (2015 – 2020) are similarly governed by the contracts with customers, however these contracts have been revised to clearly distinguish between the LCC work performed for the third party, and the gifting of the resulting assets to Energex (as the DNSP). These projects are treated as opex, with the expense and revenue recognised on completion. While in progress, these projects are recognised as recoverable work in progress on the balance sheet.

This change in treatment will result in two different approaches being reported for LCC projects, through until all contracts established under the previous Determination period are completed and energised.

Rearrangement of network assets

In the previous Determination period, large rearrangement of shared network assets were treated as SCS capex that received capital contributions, consistent with the transitional approach that applied to Queensland DNSPs for contributions.

From the current Determination period, all rearrangement of shared network assets are treated as ACS. Large projects are accounted for as capex (and excluded from the RAB) with expenditure recognised as incurred. Revenue is not recognised until the asset is fully constructed and energised. Small rearrangement of shared network assets projects continue to be treated as opex, with the expense and revenue recognised on completion. While in progress, these projects are recognised as recoverable work in progress on the balance sheet.

This change in treatment will result in the new large projects for rearrangement of shared network assets being reported in Template 4.4 Quoted Services. Any large rearrangement projects already in progress at the start of this Determination period will continue under the previous treatment and be reported as SCS capex.

Emergency Recoverable Works

Services for Emergency Recoverable Works are no longer reported in Template 4.4 Quoted Services as they have been reclassified as unregulated from the current Determination period.

After Hours Provision of any Fee-Based Service

Consistent with Energex's Pricing Proposal from 2015/16, this service is no longer a separate Quoted Service and is instead reported as part of the underlying Fee-Based Service.

Supply abolishment – complex

Due to the immateriality, Supply Abolishment is no longer disaggregated between Simple (Fee-Based) and Complex (Quoted). All Supply Abolishment services are now reported as Fee-Based only.

Additional Crew

Similar to *After Hours Provision of any Fee-Based Service*, the service for Additional Crew is now captured as part of the underlying Fee-Based Service.

31. BoP 5.2.1- Asset Age Profile Installed Assets Currently in Commission

The AER requires Energex to provide the following information relating to Table RIN 5.2.1 – Asset Age Profile:

Asset Volumes currently in commission, split by the following asset categories:

- **Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)**
- **Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)**
- **Underground Cables By: Highest Operating Voltage**
- **Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV)**
- **Switchgear By: Highest Operating Voltage ; Switch Function**
- **Public Lighting By: Asset Type ; Lighting Obligation**

Estimated Information was provided for the following figures:

- **Switchgear By: Highest Operating Voltage ; Switch Function**
  - **< = 11 KV; Operational Switch (Years 1910/11 and 1965/66 – 2001/02)**
- **Public Lighting By: Asset Type ; Lighting Obligation**
  - **Luminaires; Major Road**
  - **Luminaires; Minor Road**
  - **Lamps; Major Road**
  - **Lamps; Minor Road**

All other figures reported are Actual Information.

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

This Basis of Preparation excludes:

- **Asset Category: Service Lines By: Connection Voltage; Customer Type; Connection Complexity – which is covered in a Basis of Preparation 5.2.2.**
- **Mean Economic Life and Standard Deviation information across all asset groups: which is covered in Basis of Preparation 5.2.3**
- **Asset Category: SCADA, Network Control and Protections Systems By: Function – which is covered in a Basis of Preparation 5.2.4.**

31.1 Consistency with CA RIN Requirements

Table 31.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 31.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 5.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category. Energex must provide corresponding replacement expenditure data in the Regulatory Template.	The categories were reported in accordance with the values in Regulatory Template 2.2 – Repex
In instances where Energex considers that both the prescribed asset group categories and the sub-categorisation do not account for an asset on Energex's distribution system, Energex must insert additional rows below the relevant asset group to account for this. Energex must provide the required data, applying a high level descriptor of the asset as the category name. The line item titled "OTHER - PLEASE ADD A ROW IF NECESSARY AND NOMINATE THE CATEGORY' illustrates this requirement. Energex must provide corresponding age profile data in Regulatory Template 2.2 as per its respective instructions.	The categories "Other By Additional categories" have been included in the "Other By: DNSP defined" section of table 5.2.1 as follows: • Additional categories for Regulators were reported in accordance with the values in Regulatory Template 2.2 – Repex – Other By: Regulator • Additional categories for Pole Mounted and Kiosk Mounted Transformers were reported in accordance with the values in Regulatory Template 2.2 – Repex – Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phasing (At LV)

31.2 Sources

Table 31.2 sets out the sources from which Energex obtained the required information.

Table 31.2: Information sources

Variable	Source
Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)	DMA
Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)	DMA
Underground Cables By: Highest Operating Voltage	DMA
Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV)	DMA
Switchgear By: Highest Operating Voltage ; Switch Function	DMA

Public Lighting By: Asset Type ; Lighting Obligation	DMA

31.3 Methodology

All data was extracted from DMA. These data extracts were then manipulated in excel to account for various items in the figures.

31.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

- The pole data does not include assets that are in store or held for spares.
- The pole data was categorised by the highest voltage at the site. For example if a site carries 33KV and 11KV conductors, then all poles at the site were allocated as 33KV poles.
- All non-staked and nailed poles have a year of commissioning based on the first year the current specification was allocated to the slot in NFM.
- A pole with a pole foundation type of staked and nailed has an age profile of when the pole foundation was made staked and nailed and not as per first year of current specification.
- Poles that have a material type of plastic were excluded.
- Aluminium poles were combined with steel poles.
- Poles with a dedicated streetlight pole specification and contain a rate 1 or rate 2 streetlight has not been included in the asset group poles but was included in the public lighting asset group.
- All poles with no voltage such as cross street and bollard poles were allocated to the <=1KV category.
- The total quantity and year of commissioning is a snapshot of all relevant assets as of 30 June 2016.
- All Steel Poles found in Substations are allocated to <=1KV category. These poles are not used for the distribution of electricity.
- All Steel Poles with a Voltage of <=1KV were moved to unmatched category for data quality investigation.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

- The conductor data does not include conductors that are in store or held for spares.
- Total quantities are reported in kilometres.
- The length of each conductor category is the total conductor route length and not each individual phase conductor length, noting:
  - 11KV routes predominately consist of 3 conductors. 11KV routes also include 3 phase and single phase (2 conductors) in its total length.
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral; however lengths provided includes all variations.

Underground Cables By: Highest Operating Voltage

- The underground cable data does not include cables that are in store or held for spares.
- Total quantities are reported in kilometres.
- The length of each conductor category is the total cable route length and not each individual core length.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

- The transformer data does not include transformers that are in store or held for spares.

Switchgear By: Highest Operating Voltage; Switch Function

- The switchgear data does not include assets that are in store or held for spares.
- Circuit Breakers asset group was defined as all circuit breakers and reclosers within the Energex network excluding circuit breakers that form part of a Ring Main Unit.
- Operational Switch asset group was defined as all other switches found within Energex network, This includes the asset types Air Break, Disk Link, Link Pillar, Isolator, Switch Fuse, Dropout, Earth Switch, Fuse Switch, Sectionaliser, Load Transfer Switch, Ring Main Unit, and Disconnect Box.

Public Lighting By: Asset Type; Lighting Obligation

- The public lighting data does not include assets that are in store or held for spares.

Other By - Regulators: Asset Location; Highest Operating Voltage

- The Regulators data does not include Regulators held in stores or held in spares.
- Regulators greater than 22KV and in substations are considered to have one regulator tank per unit, all other Regulators are considered to have 2 tanks per unit.

31.3.2 Approach

Energex applied the following approach to obtain the required information:

Profiling methodologies used are as follows:

1) GlobalProrata – used to prorata source groupings over target groupings based on complete loaded source data across all dimensions

2) Prorata – used to prorata a set of source groupings over a set of target groupings

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

The DMA Solution has correctly identified the categories and missing data has been minimised and therefore Poles is no longer estimation data.

1) A report was extracted from DMA that detailed the poles in the Energex network with the following corresponding information:
    a. The pole material.
    b. The pole foundation.
    c. The original installation year.
    d. The number of poles.

    This report excluded all poles that are not currently in use by Energex..

2) The report output from DMA was then Rounded in Excel to produce the figures required in table 5.2.1. Adjustments were made for:
    a. Poles dated pre-1923.
    b. Allocation of poles made of other or unknown materials.
    c. Errors in staked and nailed poles.
    d. Pre-1970 Steel LV poles.
    e. Poles without an assigned voltage (cross street and bollard poles).

3) When any of the pole information found in 2), data was adjusted in these improved ways based on DMA RIN Configuration Solution:

    a. Global Prorata – This process involves taking all poles with complete information and generating a profile for all the Pole outcomes. Poles then with missing information are allocated across the all possibilities based on the percentages generated by the profile.

    b. Prorata – The data is found in a particular group i.e. Poles dated pre 1920. A profile is then created based on the data found at the destination of the Prorated data i.e. 1970 through to 1999. The data is then distributed across the range based on the Profile.

4) When data migration occurred into NFM in 1999, assets that were contained within the original database that did not have a known age were allocated an install date of 1920 or earlier. Any pole actually this old will have had a like for like replacement since then and if this was before 1999 the date not historically recorded. So all poles in this group were prorated 1970 to 1999.

5) Poles that have a material type of plastic were excluded.

6) All poles that cannot be allocated a material type or age because they do not have a specification recorded in DMA were prorated.

7) Staked and nailed poles with an age of older than 1996 are deemed to be in error. The trial of pole nailing within Energex only occurred during the 1995-96 period and started rolling out into the network in 1998. The age of a staked and nailed pole is based on current data in DMA. This data was prorated into the years 1999-2002.

8) Steel LV poles with a date record pre 1970 were prorated to the period of 1970 to1999. This was done because (a) LV steel poles have a mean life of 22 years and all poles prior to 1970 were deemed to be data anomalies and (b) the NFM data after 1999 is considered to be sound.

9) All poles with no voltage such as cross street and bollard poles were allocated to the <=1KV category.

10) All Steel Poles found in Substations are allocated to <=1KV category. These poles are not used for the distribution of electricity.

11) All Steel Poles with a Voltage of <=1KV were moved to unmatched category for data quality investigation.

12) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

1) Energex produces conductor age based on pole age which is the best data available. Poles were chosen because there is a correlation between poles and conductors and pole data is extremely accurate.

2) A report was run from DMA that gave the Energex overhead conductors broken down by:

    a. Conductor sizing category (Imperial, Metric or Other).

    b. The circuit for each conductor.

    c. The minimum pole installation date within each circuit.

All lengths extracted exclude any vertical components to the conductor, such as sag.

3) Excluded from this report were conductors known to be owned by customers. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurs Energex has captured these conductors. In addition, assets that were sold to customers, where Energex believes that there is a benefit to continue to store this data, have not been removed from NFM, but are excluded from RIN reporting.

4) To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor is also customer owned.

Table 31.3: Volumes of Customer Owned Conductors

Customer Conductor	Quantity (km)
Overhead	5.03

5) The following approach was then used to create the age profile:

   a. 1929-30 was deemed to be the maximum possible age of any conductor by Energex's technical standards.

   b. All conductors were placed into 3 categories by delineating them based on imperial and metric sizing:

      i. Imperial –This conductor category consists of conductors that use imperial sizing such as 7/0.80 and were superseded by metric conductors. These conductors were used from 1930 – 1980

      ii. Metric – This conductor category was used from 1970 till present, these use metric sizing such as MARS 7/.375

      iii. Other – This conductor category consists of imperial sizing that Energex currently uses such as 7/12 Steel, therefore these conductors are deemed to be used from 1930 - present.

      iv. Any conductor's age that falls outside the groups above is prorated throughout its expected age range.

   c. All conductors were then logically grouped together based on circuit (continuous conductor spans between two operational points in the network) and conductor category.

   d. All conductors missing attribute information have received a global prorata.

6) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur.

Underground Cables By: Highest Operating Voltage

1) Energex produces cable age based on equipment age which is the best data available. Equipment was chosen because there is a correlation between equipment and cable. Equipment data is extremely accurate.

2) A report was run from DMA that gave the Energex underground cables broken down by:

   a. Cable sizing category (Imperial, Metric or Other).

   b. The circuit for each cable.

   c. The minimum connected asset installation date within each circuit.

   All lengths stated exclude any vertical components to the cable, such as vertical tails.

3) Excluded from this report were cables known to be owned by customers. Cables are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these cables captured. In addition assets that were sold to customers and Energex believes there is a benefits to continue to store this data the data has not be removed from NFM.

4) To minimise the effect of captured customer cables, it was assumed that where a cable is connected to only customer assets then that cable is also customer owned.

Table 31.4: Volumes of Customer Owned Cable

Customer Conductor	Quantity (km)
Underground Cable	13.91

5) The following methodology was used to create the age profile:

   a. 1929-30 was deemed to be the maximum possible age of any conductor by Energex's technical standards.

   b. All cable were placed into 3 categories by delineating them based on imperial and metric sizing:

      i. Imperial –This cable category consists of cables that use imperial sizing such as 0.15sq and were superseded by metric cables. These conductors were used from 1930 – 1980.

      ii. Metric – This cable category was used from 1970 till present, these use metric sizing such as 240mm sq.

      iii. Other – This cable category consists of imperial sizing that Energex uses. There are no underground cables that fall into this category; if cable did exist they would have an acceptable age profile from 1930 - present.

iv. Any conductor's age that falls outside the groups above is prorated throughout its expected age range.

c. All cables were logically grouped together based on circuit (continuous connection between two operational points in the network) and cable category. All cables then inherited the maximum age (oldest) of the connected assets that was acceptable within the particular grouping. Where an acceptable age profile could be found, all conductors with a metric category are allocated an age of 1974-75 and an imperial category are allocated an age of 1944-45.

6) All cables missing attribute information have received a global prorata.

7) The approach above uses the minimum date a connected asset was installed. Unlike poles, which have had a maintained age prior to NFM, the underground network has many assets that were not tracked prior to NFM. As such, the data capture exercise performed when migrating to NFM caused 2 notable spikes in the originally extracted data: 2001-02 period for the underground LV network and 1999-00 for the 11KV network. To smooth out these spikes the data was distributed back until 1985. This was because 1985 was the year in which contractors took over subdivision development and there was a push to have all subdivisions made underground from this point forward within the Energex region. The data for both spikes was smoothed using a linear regression prediction based on the known data from 2016 through to the year before the spikes occurred.

8) Due to rounding errors, some cables had to be manually added to or subtracted from to ensure consistency of the final figure.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

The DMA Solution has correctly identified the categories and missing data has been minimised and therefore transformers are no longer estimation data.

1) A report was run from DMA which counted the number of transformers broken down by:

   a. Mounting type.

   b. Capacity.

   c. Phasing.

   d. Manufacture year

   e. Highest Operating Voltage

   Transformers recorded in DMA as being In Service and Inferred In service were counted in the total number of assets and year of commissioning information. This method gave (a) the most accurate number currently in use as (b) the date that connectivity information is captured correlates closely with the actual commissioning date.

2) In this extract the year indicated for each asset type is the year the asset was manufactured. If this date was unknown or incorrect (less than 1910 or greater than 2016) then the first event associated with the asset (usually purchase date) was used. If this date was unknown then the date the slot was installed into NFM was used.

3) Transformers with the following unknown values were prorated using a Global Prorata:

   a. Transformers with unknown ratings.

   b. Transformers with unknown dates.

   c. Transformers with unknown phasing.

All values were allocated by prorating across known asset quantities in each category.

4) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur.

Switchgear By: Highest Operating Voltage: Switch Function

1) A report was run within DMA which extracted the number of switchgear assets broken down by operating voltage and switch function. Switchgear which was recorded in NFM as being connected to the network was counted in the total number of assets and year of commissioning information. This excluded Link Pillars, Ring Main Units and Disconnect Boxes as these assets do not have a connectivity connection. This method gave (a) the most accurate number currently in use as (b) the date that connectivity information was captured correlates closely with the actual commissioning date.

2) The following definitions were used in the extraction of the data:

   a. The switchgear data did not include assets that are in store or held for spares.

   b. Operational Switch asset group was defined as all other switches found within Energex network, This includes the asset types Air Break, Disk Link, Link Pillar, Isolator, Switch Fuse, Dropout, Earth Switch, Fuse Switch, Sectionaliser, Load Transfer Switch, Ring Main Unit, and Disconnect Box.

   c. Circuit Breakers asset group was defined as all circuit breakers and reclosers within the Energex network excluding circuit breakers that form part of a Ring Main Unit.

3) The year indicated for each asset type was the year the asset was manufactured, if this date was unknown or incorrect (less than 1910 or greater than 2016) then the first event associated with the asset (usually purchase date) was used. If this date was unknown then the date the slot was installed into NFM was used. No other date information was available for some assets with dates less than 1910. These assets where prorated from years 1912 through to 2016.

4) There was a large spike of <=11KV switches in the 1999-2002 period due to the increased scope of data capture caused by the NFM data capture project. To account for this spike the actual information was used to generate a profile shape which was used to distribute the data which was only achievable through the efficiencies provided by the DMA RIN Configuration Solution.

5) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur.

Public Lighting By: Asset Type; Lighting Obligation

1) A report was extracted from DMA which counted each public light broken down by the following information:
   a. Streetlight age.
   b. Streetlight rate.
   c. Billing type.
   d. Lamp category.

2) This report did not include assets that are in stores or held for spares. Also, only rate 1 and 2 streetlights have been included in the extract. Rate 1 streetlights are designed, constructed, owned and operated (maintained) by Energex. Rate 2 streetlights are customer designed and constructed which are owned, operated and maintained by Energex. Rate 3 and 8 streetlights were not included as they are owned and operated by the customer and not required to be maintained by Energex. Rate 9 streetlights were not included as they are watchman lights and did not fit the criteria of a streetlight for the CA RIN.

Luminaires

1) Initial luminaire installations are captured within NFM; however, subsequent streetlight head changes are not captured, so for this reason an age profile had to be estimated. It was assumed that all streetlights prior to 1997 have been replaced with a consecutive 20 year life span. For example a 1979 start date was updated to 1999 to indicate that the asset was replaced. A 1934 streetlight will inherit a new asset age of 2014 to represent three head changes with a 20 year life for each.

2) Major and minor allocations for luminaires were based on the billing type of the lantern.

Lamps

1) Detailed lamp information is not stored within the Energex corporate systems. For this reason estimates were applied based on the average life of assets lamps. Average life of lamps can be broken into two categories, mercury vapour and other lamp types. Mercury vapour lights have an average life of 5 years and all other lights have an average life of 4 years.

All lights that were installed prior to the average life expectancy (prior to 201206 for Mercury Vapour and 201306 for other types) have been accumulated and applied consistently into each year.

Brackets

1) It was assumed that a bracket was installed for all streetlights that are mounted on a pole. Due to very limited number of brackets being replaced, all brackets have inherited the original streetlight age profile.

Poles

1) Poles were deemed to be a streetlight pole when the specification was public lighting specific and contained a rate 1 or 2 streetlight. The age of the poles was taken as the original streetlight age profile.

2) The categorisation of poles to major or minor was inherited from the streetlights attached to the pole. Where multiple streetlights existed on the pole the major streetlight took precedence.

3) Poles with an installation year less than 1970 were prorated into the year 1970 – 1999.

Other - By Regulators: Asset Location; Highest Operating Voltage

Regulators

1) Regulators where broken down by:
   a. Location
   b. Highest Operating Voltage

2) Regulators where deemed to be 2 tanks per unit on all network except Substation >22KV where1 tank per unit was used.

Other – By Towers

1) Towers were grouped by year.

31.4 Estimated Information

Estimated Information was provided for the following line items:

- *Switchgear By: Highest Operating Voltage; Switch Function*
- Public Lighting By: Asset Type ; Lighting Obligation:
  – Luminaires; Major Road.

– Luminaires; Minor Road.
– Lamps; Major Road.
– Lamps; Minor Road.

31.4.1 Justification for Estimated Information

Switchgear By: Highest Operating Voltage; Switch Function

- 11kV Switchgear which was installed between the years 1999 to 2002 were found to be commissioned between 1979 and 2002. This was determined because there was another data capture in 1978. This required an apportioning of the data through 1979 and 2002, otherwise our switchgear would be underaged and we would be replacing higher quantities then expected.

Public Lighting By: Asset Type; Lighting Obligation

- Initial luminaire installations are captured within NFM; however, subsequent streetlight head changes and Lamp changes are not captured, so we are unable to determine the correct replacement date for piece of equipment and cannot create an accurate age profile. The data had to be estimated.
- Detailed lamp information is not stored within the Energex corporate systems. For this reason estimates were applied based on the average life of assets lamps.

31.4.2 Basis for Estimated Information

Switchgear By: Highest Operating Voltage; Switch Function

- 11KV switches in the 1999-2002 period due to the increased scope of data capture caused by the NFM data capture project. To account for this spike the actual information was used to generate a profile shape which was used to distribute the data.
- The above solution is the best possible solution because
  - The profile used actual data gathered in the time period to predict what would have been captured during the 1999-2002 period.
  - The actual data and the prediction data is then used to model what occurred from 1979 through to 2002.
  - The Profile generated for switches matches purchasing trends of other equipment over the same time period e.g. transformers in similar voltage range.
  - Previous methods for profiling have been trialled where we used a flat prorata and standard prorata but these were unable to give accurate representation of the 1979 – 2002 data.

Public Lighting By: Asset Type; Lighting Obligation

- Luminaires have been estimated by using a 20 year life span and assuming that each one was replaced on this schedule.
- Lamps have been estimated by using the average asset lives of lamps (5 years for Mercury Vapour and 4 years for other types) and assuming that each was replaced on this schedule. For full details please refer to the approach section above. Currently there is no other approach due to the lack of data.
- Currently there is no other approach due to the lack of data, but we are working with contractors to obtain better information on yearly replacements.

31.5 Explanatory notes

- Where, in Regulatory Template 2.2, Energex provided estimated expenditure data on the basis of historical data that included works across asset groups, Energex provided the asset age profile data in Regulatory Template 5.2 against the most elementary asset category (as per RIN regulatory requirement).
- On 9 July 2015 the AER advised that information relating to Asset Group: “Pole Top Structures by Highest Operating Voltage” was not required to be populated in Regulatory Template 5.2. On 7 August 2015 the AER confirmed that Energex could leave this section of table 5.2.1 blank.

32. BoP 5.2.2 - Asset Age Profile Service Lines

The AER requires Energex to provide the following information relating to RIN Table 5.2.1 – Asset Age Profile:

- **Service Lines By: Connection Voltage; Customer Type; Connection Complexity**

All figures are derived actual information (as exact historic install dates are not known).

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

32.1 Consistency with CA RIN Requirements

Table 32.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 32.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Service lines Includes assets that provide a physical link and associated assets between the distribution network and a customer's premises. It excludes any pole mounted assets and meters that are included in any other asset group.	Addressed in section 32.3 (Methodology) and section 32.3.1 (Assumptions).
Simple commercial/industrial connection low voltage Single/multi-phase *customer* service *connection* and, as an example, may involve the following: – One or more spans of overhead service wire. – Road crossing (overhead or underground). Small LV extension or augmentation of overhead and/or underground mains.	Addressed in section 32.3 (Methodology) and section 32.3.1 (Assumptions).

32.2 Sources

Table 32.2 sets out the sources from which Energex obtained the required information.

Table 32.2: Information sources

Variable	Source
Service Lines By: Connection Voltage; Customer Type; Connection Complexity	MARS

Variable	Source
Service Cable – Replacements	Spreadsheets (Manually Captured)
Service Cable - New net NMIs connected as Overhead	PEACE CUS16 BO report

32.3 Methodology

- Overhead service line asset information is stored in MARS (Meter Asset Register and Service system). MARS does not record the age of assets, but it does record the type of conductor. The type of conductor has been used to derive the age of the assets.
- Based on the definitions specified in the RIN, Energex has only LV service line assets. Where customers require more complex connections and the assets are owned by Energex they are included in the other dedicated asset category (e.g. 11 kV overhead conductor) and are not classified as HV service lines.

32.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Maximum age of a service line is 60 years.
- All new service line assets are XLPE. Energex only owns LV service line assets. A Customer may have their own private Network past the HV connection point however Energex does not model/capture their assets. For example, consumers own the mains from underground pillars at the property boundary to their meter position, so no underground services are included in the count.
- All LV service lines are a single span making them simple connections.

32.3.2 Approach

The breakdown of service line conductor was extracted from MARS through the following logic:

1) The total quantity of OH service lines were extracted based on unique property addresses:
    a. All NMIs with the same street number are recorded as one NMI to accommodate unit blocks.
    b. Instances of NMIs with no street number were counted once for each lot number
    c. Instances of NMIs with no street number and no lot number were counted once.

2) Each record needed to have a National Metering Identifier (NMI) associated with the property with one of the following statuses for the NMI:

   a. Active ('A').

   b. De-Energised ('D').

   c. Can be metered or unmetered.

3) Overhead services were identified as:

   a. A NMI with a supply type which does not start with a 'U%' identifier (unless the Pole Value indicates overhead) or a "null" identifier.

   b. A pole value that does not start with SC, SG, SS or 'U%' identifier. (SC, SG and SS denote substation sites, and U% is underground pillar sites).

This data is used as the starting point (base) then replacements + new services are added.

New Installs / Replacements / Asset Age

1) The replacement volume and recent installation information was used to estimate the installation of XLPE type cables over the last 19 years. Remaining cable types were spread evenly across the estimated age range.

2) Quantities of assets inspected/maintained for service lines were based on the number of services maintained during the year, as opposed to the number of customers.

3) The expected age range of the different generations of cables was then included to determine the age profile. These assumptions are as per

4) Table **32.3** below:

Table 32.3: Expect Age Range for Cable Types

CABLE_TYPE	Age Install Range
B (Bare Open)	Any
N (Concentric Neutral)	29-40
O (Open wire Neutral)	40+
P (Parallel web)	19-40
T (Twisted multiphase)	19-40
X (XLPE)	0-19
XMT (XLPE Mitti)	9-11
Y (4x95 XLPE)	0-19

UNKNOWN	Any

5) The next step was to generate an age profile for each cable type based on:
   a. The expected age range of assets in-service.
   b. Maximum life of service lines.
   c. Known replacement and installation volumes over the last 5 years.

6) New NMIs that became ‘Active’ in the financial year and were overhead were also included (minus temporary connections from TBS and Supply Abolishments for overhead services). This is done by identifying ‘Erect Service’ work that Energex has completed. This leaves a ‘net’ new number of NMIs with overhead service cable.

7) After the total service line population was determined the profile was split into Residential, Commercial & Industrial and Simple and Complex. The split between Residential and Commercial & Industrial service lines was based on the historic split between these two customer types (approximately 8% C&I and 92% residential).

8) Replacement information is broken into:
   - XLPE Mitti service replacements
   - PVC and twisted service replacements
   - Open wire and concentric neutral services.

These replacements are evenly distributed and removed from the previous year’s population.

Actual Information

Figures from a) the MARS Database as a baseline b) the Replacement Spreadsheet and c) CUS 16 BO report from PEACE are considered actual rather than estimated information.

32.4 Estimated Information

32.4.1 Justification for Estimated Information

32.4.2 Basis for Estimated Information

32.5 Explanatory notes

For LV connections, Energex does not own the underground cable from the pillar to the premise. Therefore only overhead services were included in the table.

Between 2005/6 and 2004/5 there were a low number of cables remaining in service. This is due to the replacement program for a specific type of XLPE cable that exhibited problems with degraded insulation.

33. BoP 5.2.3 - Asset Age Profile Economic Life and Standard Deviation

The AER requires Energex to provide the following information relating to RIN Table 5.2.1 – Asset Age Profile:

Mean economic life and standard deviation for the following asset groups:

- **Poles, disaggregated by highest operating voltage and material type**
- **Overhead conductors, disaggregated by highest operating voltage and number of phases**
- **Underground cables, disaggregated by highest operating voltage**
- **Service lines, disaggregated by, connection voltage, customer type and connection complexity**
- **Transformers, disaggregated by mounting type, highest operating voltage, ampere rating and number of phases**
- **Switchgear, disaggregated by highest operating voltage and switch function**
- **Public lighting, disaggregated by asset type and lighting obligation**
- **SCADA, network control and protections systems, disaggregated by function**

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

33.1 Consistency with CA RIN Requirements

Table 33.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 33.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Definition of economic life: An asset's economic life is the estimated period after installation of the new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. The period of effective service needs to consider the life cycle costs between keeping the asset in commission and replacing it with its modern equivalent.	Demonstrated in section 33.3 (Methodology).

Life cycle costs of the asset include those associated with the design, implementation, operations, maintenance, renewal and rehabilitation, depreciation and cost of finance.	
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 5.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category. Energex must provide corresponding replacement expenditure data in Regulatory Template 2.2 as per its instructions	Demonstrated in section 33.3 (Methodology).
In instances where Energex is reporting expenditure associated with asset refurbishments/ life extensions capex it must insert additional rows at the bottom of the table for the relevant asset group to account for this. Energex must provide the required data, applying the corresponding asset category name followed by the word "REFURBISHED". Energex must provide corresponding replacement expenditure data in Regulatory Template 2.2 as per its respective instructions.	Demonstrated in section 33.3 (Methodology).
In instances where Energex wishes to provide asset sub-categories in addition to the specified asset categories in table 5.2.1, Energex must provide a weighted average asset economic life, including mean and standard deviation that reconciles to the specified asset category in accordance with the following formula: $\text{Economic life of asset category}=\sum_{i=1}^{n}\left(\left(\frac{\text{value of asset sub-category}_i}{\text{total value of asset category}}\right)\times\text{economic life of asset sub-category}_i\right)$ where: n is the number of sub-categories to reconcile with the asset category Asset values are determined by the asset category's contribution to the current replacement cost of the network. This being the most recent per unit cost of replacement for each asset, multiplied by the number of those assets in service and reported in the asset age profile.	Demonstrated in section 33.3 (Methodology).

33.2 Sources

Table 33.2 sets out the sources from which Energex obtained the required information.

Table 33.2: Information sources

Asset Group	Variable	Source
Poles	All Poles - Wood <=66kV	DMA
	All Poles – Wood >66kV	Engineering Assessment
	All Staking of Wooden poles	DMA

Asset Group	Variable	Source
	All Poles - Steel <=66kV	EGX CBRM - Steel Poles & Steel Street Light Poles ver AER 2016
	All Poles – Steel >66kV	Engineering Assessment
	All Poles –Concrete	Engineering Assessment
	Towers	Engineering Assessment
Overhead Conductor	< ≈ 1 KV	Engineering Assessment
	> 1 KV & < ≈ 11 KV	
	> 11 KV & < ≈ 22 KV ; SWER	
	> 22 KV & < ≈ 66 KV	
	> 66 KV & < ≈ 132 KV	
Underground Cables	< ≈ 1 KV	Engineering Assessment
	> 1 KV & < ≈ 11 KV	
	> 22 KV & < ≈ 66 KV	EGX CBRM - 33kV Gas Cables ver AER 2016EGX CBRM - 33kV Oil Filled Cables ver AER 2016EGX CBRM - 33kV Solid Cables ver AER 2016
	> 66 KV & < ≈ 132 KV	Energex CBRM - 110kV Oil Filled Cables ver AER 2016Energex CBRM - 110kV Solid Cables ver AER 2016
Service Lines	ALL	Engineering Assessment
Transformers	POLE MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; SINGLE PHASE	Energex CBRM - Pole Mounted TX ver AER 2016
	POLE MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; SINGLE PHASE	
	POLE MOUNTED ; < ≈ 22KV ; > ≈ 600 KVA ; SINGLE PHASE	
	POLE MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; MULTIPLE PHASE	
	POLE MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	
	POLE MOUNTED ; > 22 kV ; < = 60 kVA	
	POLE MOUNTED ; > 22 kV ; > 60 kVA and < = 600 kVA	
	KIOSK MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; MULTIPLE PHASE	Energex CBRM - Ground & Pad Mounted TX ver AER 2016
	KIOSK MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	

Asset Group	Variable	Source
	KIOSK MOUNTED ; < ≈ 22KV ; > 600 KVA ; MULTIPLE PHASE	
	KIOSK MOUNTED ; > 22 KV ; < ≈ 60 KVA	
	KIOSK MOUNTED ; > 22 KV ; > 60 KVA AND < ≈ 600 KVA	
	KIOSK MOUNTED ; > 22 KV ; > 600 KVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; < ≈ 60 KVA ; MULTIPLE PHASE	Energex CBRM - Ground & Pad Mounted TX ver AER 2016
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 600 KVA ; MULTIPLE PHASE	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > ≈ 22 KV & < ≈ 33 KV ; < ≈ 15 MVA	EGX CBRM 33kV TR ver AER 2016
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > ≈ 22 KV & < ≈ 33 KV ; > 15 MVA AND < ≈ 40 MVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > ≈ 22 KV & < ≈ 33 KV ; > 40 MVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < ≈ 66 KV ; > 15 MVA AND < ≈ 40 MVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < ≈ 132 KV ; < ≈ 100 MVA	EGX CBRM 110.132kV TR ver AER 2016
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < ≈ 132 KV ; > 100 MVA	
	REGULATOR ; SUBSTATION < = 22kV	Energex CBRM - regulators ver AER 2016
	REGULATOR ;DISTRIBUTION < = 22kV	
	REGULATOR ; SUBSTATION > = 22kV	
Switchgear	< ≈ 11 KV ; CIRCUIT BREAKER	EGX CBRM 11kV CB ver AER 2016
	> 11 KV & < ≈ 22 KV ; CIRCUIT BREAKER	
	< ≈ 11 KV ; OPERATIONAL SWITCH	Engineering Assessment
	> 11 KV & < ≈ 22 KV ; OPERATIONAL SWITCH	
	> 22 KV & < ≈ 33 KV ; CIRCUIT BREAKER	EGX CBRM 33kV CB ver AER 2016

Asset Group	Variable	Source
	> 33 KV & < ≈ 66 KV ; CIRCUIT BREAKER	
	> 22 KV & < ≈ 33 KV ; OPERATIONAL SWITCH	Engineering Assessment
	> 33 KV & < ≈ 66 KV ; OPERATIONAL SWITCH	
	> 66 KV & < ≈ 132 KV ; CIRCUIT BREAKER	EGX CBRM 110.132kV CB ver AER 2016
	> 66 KV & < ≈ 132 KV ; OPERATIONAL SWITCH	Engineering Assessment
Public Lights	Luminaires	Manufacturer's specification
	Brackets and Poles	EGX CBRM - Steel Poles & Steel Street Light Poles ver AER 2016
	Lamps	Ellipse and SLIM/NFM (Oracle)
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS	ALL	Engineering Assessment and Age profile info sources from IPS, SCADABase, CBMD, ROSS, CNMS, Project documents and asset spreadsheets.

33.3 Methodology

- Condition Based Risk Management (CBRM) is the tool used for asset replacement planning on a condition and risk management basis. CBRM analysis was reviewed recently. It was therefore considered applicable to use this analysis for the CA RIN.

- For the majority of asset classes, economic life data was extracted from CBRM models. For asset classes where Energex does not have CBRM to model asset condition, engineering assessments and DMA were performed to estimate the mean economic life.

- In all cases the standard deviation of economic life was approximated by the square root of the mean.

33.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Standard deviation of economic life was approximated by the square root of the mean in accordance with the AER guidance.

- The economic life of <=22kV wood poles was assumed to be the same as 11kV wood poles.

- The economic life of SWER conductor was assumed to be the same as 11kV conductor.

- The economic life of low voltage cables (i.e., <=1kV) was assumed to be the same as 11kV cables.
- The economic life of poles with unknown voltage (i.e., <=1kV) have been included with low voltage poles.
- The economic life of pole mounted single phase transformers was assumed to be the same as multi-phase pole mounted transformers.
- The economic life of ground mounted/indoor chamber mounted transformers >33kV and <=66kV was assumed to be the same as 33kV ground mounted/indoor chamber mounted transformers.
- The economic life of >11kV and <=22kV circuit breakers and switches was assumed to be the same as11kV circuit breakers and switches respectively.
- The economic life of >33kV and <=66kV circuit breakers and switches was assumed to be the same as 33kV circuit breakers and switches respectively.

33.3.2 Approach

Economic life information for the majority of asset classes was extracted from CBRM models. Where CBRM models had not been undertaken on particular asset category, engineering assessments and DMA were undertaken to estimate economic life of assets.

CBRM Models

- CBRM is an approach to asset replacement planning that forecasts the future condition of assets and enables the modelling and evaluation of different investment scenarios.
- CBRM enables asset lives to be expressed based on attributes of assets combined with its location and duty in the network. The input values used in the CBRM models were developed through workshops with key stakeholders, taking account of factors such as original specification, manufacturer, operational experience, obsolescence, maintenance issues and operating conditions (duty, proximity to coast, etc.). Whilst the values for average asset lives used in CBRM model are based on subjective information, they are calibrated against historic asset failures and replacements. The calibration is reviewed regularly to ensure it remains relevant as new asset populations are introduced and mature.
- As an example, if a particular type of circuit breaker in the population began to manifest issues as a result of manufacturing or engineering factors, the observed failures would be factored into the calibration review. This in turn would modify the expected life of the population.
- Source data for CBRM comes from the DMA solution.

Modified expected life

- Where CBRM was used to provide data for economic life, it was calculated as the “modified expected life” field within each of the CBRM models.
- The modified expected life field was calculated based on the following:
  - Each asset was assigned an average asset life based on asset type or manufacturer.
  - Duty and location factors specific to the asset are then applied, based on known attributes such as load or distance to coast.
- The combination of these pieces of information in the CBRM model produces a value for the modified expected life.
- As an example, a power transformer in a corrosive environment (i.e. outdoors close to the coast), will have a significantly shorter life than a power transformer located in a more benign, dry environment.

Wood and Steel Poles

The economic life for wood poles was calculated based on analysis of data extracted from NFM. The following process was applied:

- Data for each pole was extracted from DMA listing the date of installation and the date the pole failed inspection. The replacement age of poles closely aligns with the date they failed inspection due to the programs and policies Energex have in place to replace unserviceable poles. Data imported into Excel for analysis.
- The dataset was filtered to only include poles replaced following an inspection (as opposed to poles replaced under capital augmentation works). These poles were identified based on a flag in DMA.
- The period the pole was in service was then calculated for each pole in the dataset. This was determined based on the difference between the date the pole failed inspection and the date the pole was installed.
- Each pole was then mapped to an asset category (consistent with the RIN table 5.2.1), based on the voltage attributed to the pole.
- At this point, a number of poles types were also excluded from dataset due to data quality issues, namely:
  - Poles replaced <=5 and >=100 years from installation date
- The economic life for each asset category was then determined by calculating the weighted average life across all poles in the asset category.

Staking of a wooden pole

- Data used to derive the age of nailed poles at time of replacement excludes poles nailed prior to 1995, as this was when nailing program first commenced. Owing to small populations on a voltage split basis, all nailed poles were considered as a single dataset to derive average failed inspection age from date of nailing. The data was included in the template as Pole Staking in accordance with the AER's guidance.

Concrete Poles

- A data set was not available for concrete pole actual replacement life due to their long service life and relatively new population age. As a result, the economic life for concrete poles was estimated based on the manufacturer's specification and general industry expectations.

Service Lines

- The mean economic life for service lines was estimated based on general industry life expectations.

Overhead Conductor

- The mean economic life for overhead conductors was estimated based on general industry life expectations.

Underground Cable

- The mean economic life for underground cables >11kV was extracted from CBRM models.

- The mean economic life for underground cables ≤11kV was estimated based on general industry life expectations.

Transformers

- The mean economic life for transformers was extracted from CBRM models.

Circuit Breakers

- The mean economic life for circuit breakers was extracted from CBRM models.

Operational Switches

- The mean economic life for operational switches was estimated based on general industry life expectations.

Public Lighting

Luminaires

- The mean economic life for luminaires (both major and minor) was based on the manufacturer's product specification. No differentiation was made between luminaires for major and minor roads on the basis that the manufacturer's claimed service life is identical for major and minor road luminaire fittings currently purchased.

Brackets and Poles

- The mean economic life for both brackets and poles were considered together based on the similar nature of the assets (i.e., the replacement of poles and brackets generally occur concomitantly). No differentiation was made between poles and brackets on major and minor roads on the basis that the mean economic life is equivalent for major and minor poles and brackets.
  - The mean economic life for streetlight poles was extracted from CBRM model.
- Timber poles were excluded from the calculation due to the relatively small population of timber poles used for street lighting purposes.

Lamps

The mean economic life for major and minor road lamps was estimated using current replacement rates as a proportion of the total lamp population. This was estimated using the volume of lamps issued from the store for public lighting maintenance during 2015/16, divided into the population of Rate 1 and Rate 2 luminaires installed at the end of 2015/16. This was undertaken for both Major and Minor Road Lamps. The following steps were applied (separately for major and minor road lamps):

1) The volume of lamps issued determined from an Ellipse report detailing all material issued in 2015/16 for public lighting maintenance. Lamps issued were then categorised as either Major Road or Minor Road based upon their size and type.

2) The total population of lamps was also collated (based on current billed Rate 1 and Rate 2 street lighting sites at the end of 2015-16). A report was extracted from both the SLIM database and the Oracle database to generate all the data required. This involved:

   a. SLIM.PEACE_EXTRACT-DTL is a SLIM (Streetlight Inventory Manager) table, located in the SLIM schema, containing light types and numbers for all the streetlight NMI's billed through the Peace billing system. The table provides a snapshot of the number of lights held in NFM and SLIM at the 1st day of each month. Streetlight NMI's are billed monthly and the numbers captured in this table are indicative of the number of lights to be billed as at the end of the previous month.

   b. To obtain Rate 1 and Rate 2 streetlight population as at the end of June 2016, a query was run to extract all current streetlights. The parameters used were:

      - The streetlight slot was current as at 30.6.16
      - The rate of the light was either 1 or 2

3) The lamp economic life was then calculated by dividing the 2015-16 annual lamp population over the annual lamp replacements for both major and minor road luminaires.

SCADA, Network Control and Protection Systems

This asset group includes the following asset categories:

- Field devices;
- Local network wiring assets;
- Communications network assets;
- Communications site infrastructure;
- Master station assets;
- Linear communications assets; and
- AFLC

Energex also used a number of subcategories to calculate the economic life, as set out in the Table 33.3:

Table 33.3: Asset Classes

Asset Category	Sub - Category
FIELD DEVICES	Protection Relays (MB)
	RTUs (MM)
	IEDs (PM)
LOCAL NETWORK WIRING ASSETS	Local Network Wiring Assets
COMMUNICATIONS NETWORK ASSETS	Microwave links (links installed)
	DSS Head ends
	DSS Radios (including repeaters)
	Multiplex
	MPLS Nodes
COMMUNICATIONS SITE INFRASTRUCTURE	Tower/pole
	Battery
	Charger
	Diesel
	Air conditioning
	Site security

Asset Category	Sub - Category
	Management
	Solar
	TLIU
MASTER STATION ASSETS	Master Station Assets
LINEAR COMMUNICATIONS ASSETS	Copper pilots (meters of cable installed)
	Fibre Pilots (meters of cable installed)
AFLC	Motor generator
	SFU

The economic life for each asset category was determined by calculating the volume weighted average of the subcategory asset lives. The weighted average was based on the age profiles for each subcategory and the detail for age profiles was derived from a range of system IPS, SCADABase, CBMD, ROSS, CNMS, Project documents and asset spreadsheets. For further detail on the age profiles see 5.2.4. Below details how the lives for subcategories were determined:

- For protection relays the life was estimated based on an average of 50 years for electromechanical relays and 15 years for modern digital relays (results in a life of 32.5 years). The 50 year and 15 years figures were based on current industry life expectations of the relays.
- For RTUs the mean economic life was based on analysis on historical records of asset replacement (11.6 years).
- For IED’s Engineering assessment concluded that the life of this type of equipment would be similar to that of an RTU and the figure of 12 years was chosen.
- For microwave links, DSS infrastructure and Multiplex equipment a figure of 12 years was utilised based on the equipment having an anticipated life similar to that of an RTU.
- For Local Wiring assets the life was estimated by averaging the lives of the equipment that the wiring predominately interconnects, noting that the wiring is normally replaced as part of replacing the larger asset.
- For Linear Communications Assets, asset anticipated lives for underground copper cables (60 years), overhead copper cables (30 years) were averaged to give 45 years for copper pilot cables. For overhead / underground fibre cables, 30 years was utilised. Note bracketed figures came from the “Supply System Asset Descriptions” which are part of the Energex business process for recording financial assets.

- For Master Station asset the SPARQ policy document "ICT Infrastructure Asset Renewal Guidelines" was consulted. The document states a forecast replacement age of 5 years for the types of servers utilised in the Master Station.

- For Communications Site Infrastructure the lives of the various sub components were used to generate an asset category mean life. Towers/poles (50yrs), Batteries (7yrs), Battery Charger (20yrs), Diesel Generators (15yrs), Air Conditioners (10yrs), Site Security (20yrs), Site Management (20yrs), Solar installations (10yrs) and Telephone Line Isolation Equipment (20yrs).

- For AFLC the life was derived from the average SFUI, SFUK and SFUG manufacturers expected life.

33.4 Estimated Information

In Energex certain assets do not have conditional or age data at present and as such an engineering assessment has to be undertaken. Assets with engineering assessments are considered to be estimated data.

33.4.1 Justification for Estimated Information

33.4.2 Basis for Estimated Information

33.5 Explanatory notes

Where Energex does not own assets that meet the category an economic life cells were left blank.

Differences between last CARIN (2014/15 data from Submission) VS 2015/16 CARIN methodology

Table 33.4: Comparison of 2014/15 and 2015/16 CA RIN

Category	14/15	15/16	Reason
Wood Poles	Estimated	Actual	DMA solution
Wooden Pole Staking	Estimated	Actual	DMA solution
>11kV Underground Cables	Estimated	Actual	DMA solution
Transformers (All voltages)	Estimated	Actual	DMA solution
Circuit Breakers (>=11kV)	Estimated	Actual	DMA solution
Steel and Public Lighting Poles	Estimated	Actual	DMA solution

- Comparing to previous year 2014/15, this year 2015/16 for economic mean life submission was developed using the DMA solution for only the assets shown in

Table 33.4 which has following advantages where Energex was developing in 2014/15

- DMA – RIN Solution process governance
- Data transparency and repeatability

- About DMA Solution: -

- The Distribution Monitoring Analytics (DMA) Program introduced new capabilities to support the Asset Management Division to use information about Energex's assets in a way that improves network reliability, reduces network operations risks and enables proactive cost effective maintenance.

- Previously information about our assets is housed in different repositories. DMA brought the data together so it is now easier to manage and better supports effective decision making.

- DMA was designed to provide a single source of truth for asset information. Information from multiple systems brought together in two enterprise data solutions:

  - 1.The Enterprise Data Warehouse (EDW) and

  - 2. OSI PI Historian, which currently houses SCADA information.

- The DMA program supports the vision for Energex to comply with PAS55 and ISO5500 global standards.

34. BoP 5.2.4 - Asset Age Profile SCADA, Network Control and Protections Systems By: Function

The AER requires Energex to provide the following information relating to RIN Table 5.2.1 – Asset Age Profile:

Assets currently in commission for SCADA, Network Control and Protection systems assets, broken down by the following asset categories:

- **Field Devices**
- **Local Network Wiring Assets**
- **Communications Network Assets**
- **Master Station Assets**
- **Communications Site Infrastructure**
- **Communications Linear Assets**

Data provided is actual except for Local Network Wiring Assets and AFLC which is estimated.

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

This Basis of Preparation excludes:

- **Installed Assets Currently in Commission (all other categories) which are covered in BoPs 5.2.1 and 5.2.2**

Mean Economic Life and Standard Deviation information across all asset groups: which is covered in Basis of Preparation 5.2.3

34.1 Consistency with CA RIN Requirements

Table 34.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 34.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 5.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category. Energex must provide corresponding replacement expenditure data in regulatory template 2.2 as per its instructions.	Demonstrated in section 34.3 (Methodology)
In instances where Energex considers that both the prescribed asset	Demonstrated in section

Requirements (instructions and definitions)	Consistency with requirements
group categories and the asset sub-categorisation do not account for an asset on Energex's distribution system, Energex must insert additional rows below the relevant asset group to account for this. Energex must provide the required data, applying a high level descriptor of the asset as the category name. The line item titled "OTHER - PLEASE ADD A ROW IF NECESSARY AND NOMINATE THE CATEGORY" illustrates this requirement. Energex must provide corresponding age profile data in regulatory template 2.2 as per its respective instructions.	34.3 (Methodology)
When Energex must make an estimate because it cannot populate the input cell with actual information, Energex must demonstrate that it has provided the best estimate it can.	Refer to Estimates section below.

34.2 Sources

Table 34.2 sets out the sources from which Energex obtained the required information.

Table 34.2: Information sources

Variable	Source
Field Devices • Protection Relays • Remote Terminal Units (RTUs) Intelligent Electronic Devises (IEDs)	IPS (Via DMA) SCADA Base and project documentation SCADA Base (Via DMA)
Local Network Wiring Assets	MCCS
Communications Network Assets • Microwave links • Distribution Systems SCADA (DSS) Head Ends • DSS Radios • Multiplex and MPLS	CBMD ROSS ROSS CNMS Project Documentation
Master Station Assets	Internal Excel spreadsheet
Communications Site Infrastructure • Comms Towers and Poles • Comms Batteries • Comms Battery Chargers • Diesel generators • Comms Site Air conditioners • Comms Site Security equipment	Information is manually maintained in an excel spread sheet, with the exception of the TLIU installs which are estimates

Variable	Source
• Comms Site Management equipment • Comms Site Solar Cells Telephone line Isolation equipment (TLIU)	
Communications Linear Assets	CBMD
AFLC	NFM and site visit data

34.3 Methodology

34.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- In relation to IEDs and DSS Radios, the database only contains initial commissioning information. Subsequent data associated with maintenance swap outs (i.e. replacements) is not captured due low cost of the equipment. As a result, this tends to overstate the age of the IED and DSS Radio fleet; however, this was not considered a significant issue on the basis that IEDs and DSS Radios are typically low cost in nature.

34.3.2 Approach

Energex has broken down each asset category into separate asset subcategories:

Table 34.3: Asset Classes

Asset Group	Category
FIELD DEVICES	Protection Relays
	RTUs
	IEDs
LOCAL NETWORK WIRING ASSETS	Local Network Wiring Assets
COMMUNICATIONS NETWORK ASSETS	Microwave links (links installed)
	DSS Head ends
	DSS Radios (including repeaters)
	Multiplex Nodes
	MPLS Nodes
MASTER STATION ASSETS	Master Station Assets

Asset Group	Category
COMMUNICATIONS SITE INFRASTRUCTURE	Comms Towers and Poles
	Comms Batteries
	Comms Battery Chargers
	Diesel generators
	Comms Site Air conditioners
	Comms Site Security equipment
	Comms Site Management equipment
	Comms Site Solar Cells
	Telephone line Isolation equipment (TLIU)
COMMUNICATIONS LINEAR ASSETS	Copper pilots (meters of cable installed)
	Fibre Pilots (meters of cable installed)
AUDIO FREQUENCY LOAD CONTROL (AFLC)	Generator based AFLC injection equipment
	Solid State based AFLC injection equipment

A number of different methods were used to obtain the required data for each of the asset subcategories, as follows:

Field Devices

- Protection relays – a report detailing all assets currently in commission with installation dates was extracted from IPS via DMA. The data was extracted into an Excel spreadsheet and analysed to produce the age profile data. The total number of protection relays installed in each year was determined by summing the number individual relays installed during the year. Where the commissioning date was unknown, a set of rules was used to determine the next-best date available in the database. There were a small number of relays remaining with no known installation date. These numbers were smeared across the profile of relays with known dates.

- RTUs – a review of SCADA control scheme configuration information was undertaken to identify the date when the hardware for each control scheme was changed or installed. By analysing the date when a control scheme was modified, this showed when a new asset was added. The age profile of RTUs was generated by summing the total number of hardware replacements or installations in each financial year.

- IEDs – the only class of IED that records were available for was Serial Interface Control Module (SICM) equipment. SICM represents the largest class of IEDs in SCADA in Energex's network. A report was generated from DMA (which is based on SCADA Base application extracts) that detailed the commissioning date of each IED providing the age profile.

The total number of installed assets relating to field devices was established by summing the asset volumes calculated for protection relays, RTUs and IEDs.

Local Network Wiring Assets

- For the purposes of the Local Network Wiring Assets, Energex has focused on data relating to substation multicore cabling, as this represents the primary local network wiring asset class for Energex.
- Energex's systems do not specifically record the date that each multicore cable was installed, and as a result the age profile was estimated.
- The total volume of multicore cables currently installed in substation assets was extracted from the Multicore Cable Schedule (MCCS) database (at 1 July 2016).
- The age profile is then generated by spreading the total installed amount in the same manner as the primary plant that it is connected to (substation transformers and switch gear).

Communications Network Assets

- Microwave links – The Communications Bearer Management Database (CBMD) application was queried to determine the commissioning dates for each link. This produced a list of all microwave links with the associated installation date. The data was then analysed in a separate Excel spreadsheet to determine the total number of links installed in each financial year.
- DSS Head end, radios and repeaters – The Radio Operational Support System (ROSS) application database was queried to provide the commissioning date for each asset. This produced a list of the hardware that was installed and the date of installation and commissioning. The data was analysed in a separate Excel spreadsheet to determine the total volume of equipment commissioned in each financial year.
- Multiplex – An extract of the total population of multiplex assets was performed and the total assets installed as of the 1st of July 2016 was established. The age profile for multiplex assets was estimated by analysing the installation dates associated fibre optic cables and then using these dates as a basis for apportioning the volume of multiplex assets installed for each year.
- Multi-protocol label switching (MPLS) – Volumes for MPLS assets were obtained from relevant project documentation which identified the dates of installation for each MPLS asset.

The total number of installed assets relating to communication network assets was established by summing the asset volumes calculated for microwave links, DSS head end, radios and repeaters, Multiplex and MPLS assets.

Master Station Assets

- Energex's support group for the Master Station assets maintains an Excel spreadsheet that details information about Master Station server assets. Manufacture date was used as the commissioning date.

Communications Site Infrastructure

- For Towers/poles, Batteries, Battery Charger, Diesel Generators, Air Conditioners, Site Security, Site Management and Solar installations, a spread sheet is maintained of commissioning date. The data was analysed in a separate Excel spreadsheet to determine the total numbers installed in each financial year.

- For Telephone Line Isolation Units no reliable source of installations date was available. Using Engineering assessment the figure of 250 was chosen as the total population. Discussion with Field staff suggested that no units were commissioned after 2013/14 and as such the age profile was left the same as the previous year's figures.

The total number of installed assets relating to Communications Site Infrastructure was established by summing the asset volumes calculated and estimated above.

Communications Linear Assets

- Communications Linear Assets – the CBMD application database was queried to determine commissioning dates for each point to point pilot cable link (both fibre optic cables and copper cables). The data was extracted into an Excel spreadsheet and analysed to produce the age profile data. The total length of pilot cables installed in each year was determined by summing the individual pilot cable lengths installed during the year. The length of cable without installation dates are smeared across the population based on the profile of cable with known installation dates.

Audio Frequency Load Control (AFLC)

- AFLC – the installation date for each AFLC installation was extracted from NFM into an excel spreadsheet. The installation dates were analysed versus recent audit data (approx. 40% records checked), results updated in the excel spreadsheet. The spread sheets determines the per financial year number of units installed.

34.4 Estimated Information

Estimated Information was provided for the following asset categories:

- Local Network Wiring Assets

- AFLC

34.4.1 Justification for Estimated Information

- Energex does not have historical data for Local Network Wiring.
- Data repositories for AFLC equipment were checked against a recent sample of data returned from the field. There are significant differences between the returned sample and the recorded data. A complete audit of the data is problematic due to the significant power network outage that is required to allow field staff to access the area to inspect the equipment.

34.4.2 Basis for Estimated Information

- Local Network Wiring Assets - Energex's systems do not specifically record the date that each multicore cable was installed. There are a number of potential options that could be used apportion these assets to create an age profile. These options could significantly change the age profile generated.
- AFLC Assets are based on the data found in NFM. Significant difference were found during a recent field visits. The data presented is based on the NFM data, modified by the information that has been returned from the field. As the field visit did not represent a complete audit of the data and issues have been noted with the result set the data is to be classified as estimated. This will be the focus of an improvement opportunity.

34.5 Explanatory notes

34.4.1 Justification for Actual information

Energex has significant amount of data about the various assets reported, however does not have historical data for some sub categories of the asset categories and has used various techniques to apportion these. In each case where this been done, the result either does not materially change the resulting data, no valid alternate methods are available or the judgement and assumptions do not materially affect the data.

34.5.3 Basis for claiming Estimated data as Actual

Below is detailed the justifications where estimated data has been claimed as actual data.

- Field Devices - A significant number of protection relays do not have a commissioning date and these were apportioned based on the population of the units with dates. Other valid methods could be used to apportion the 1,956 relays with no dates, however it is judged to not have a material impact given the population of 20,294 total relays.
- Communications Network Assets - Energex's systems do not specifically record the date of installation that multiplex assets were installed. The volume of installed multiplex assets was estimated by apportioning the total amount of multiplex assets

against the asset age profile of fibre optic cables. No other known valid method to do the apportionment is available.

- Master Station Assets – The dates used to populate the age profile were the equipment manufacture date. Other methods could be used to produce an age profile (e.g. projecting back from end of warranty dates), however these would not produce a material difference in the resulting profile.

- Communications Site Infrastructure - For Telephone Line Isolation Units no reliable source of installations date is available. Using Engineering assessment the figure of 250 was chosen as the total population. Discussion with Field staff suggested that the units were installed starting around 1990. There is no other valid method to develop the age profile.

- Communications Linear Assets – A significant proportion of fibre and copper pilot cables do not have installation dates (21%) and these were apportioned based on the population of the installations with dates. No other valid method is available to perform the apportionment.

35. BoP 5.3.1- Maximum Demand at Network Level

The AER requires Energex to provide the following information relating to RIN Table 5.3.1 – Maximum Demand at the Network Level:

- **Raw Network Coincident MD in MW**
- **Date MD Occurred**
- **Half Hour Time Period MD occurred**
- **Winter/Summer Peaking**
- **Embedded Generation MW**
- **10% POE Weather adjusted maximum demand, in MW**
- **50% POE Weather adjusted maximum demand, in MW**

All figures reported are Actual Information.

35.1 Consistency with CA RIN Requirements

Table 35.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 35.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In RIN Table 5.3.1, Energex must input maximum demand information at the Network level	Information on maximum demand was provided in accordance with the template
For the 'Winter/Summer peaking' line item, Energex is to indicate the season in which the raw maximum demand occurred by entering 'Winter' or 'Summer' as appropriate.	Demonstrated in section 35.3.2 (Approach)
Where the seasonality of Energex's maximum demand does not correspond with the form of its regulatory years, Energex must explain its basis of reporting maximum demand in the basis of preparation. For example, if Energex forecasts expenditure on a financial year basis but forecasts maximum demand on a calendar year basis because of winter maximum demand, Energex would state that it reports maximum demand on a calendar year basis and describe, for example, the months that it includes for any given regulatory year.	Demonstrated in section 35.3.1 (Assumptions)
Energex must provide inputs for 'Embedded generation' if it has kept and maintained historical data for embedded generation downstream of connection points and if it accounts for such embedded generation in its	Demonstrated in section 35.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
maximum demand forecast. Energex must describe the type of embedded generation data it has provided. For example, Energex may state that it has included scheduled, semi-scheduled and non-scheduled embedded generation. In this example, we would be able to calculate native demand by adding these figures to the raw maximum demand. If Energex has not kept and maintained historical data for embedded generation downstream of connection points, it may estimate the historical embedded generation data or shade the cells black. For the Regulatory Years including and after 2015 Energex must provide embedded generation data. It must do similarly if it accounts for embedded generation in its system level maximum demand forecast.	
Energex must provide inputs for the appropriate cells if it has calculated historical and forecast weather corrected maximum demand. Energex must describe its weather correction process in the basis of preparation. Energex must describe whether the weather corrected maximum demand figures provided are based on raw adjusted maximum demand or raw unadjusted maximum demand or another type of maximum demand figure. Where Energex does not calculate weather corrected maximum demand it may estimate the historical weather corrected data or shade the cells black. For the Regulatory Years including and after 2015 Energex must provide weather corrected maximum demand in accordance with best regulatory practice weather correction methodologies.	Demonstrated in section 35.3.2 (Approach)

35.2 Sources

- Energex's Network Load Forecasting (NLF) database was used to extract metered connection point half hour demand data for aggregation to the total system maximum demand. The Network Load Forecasting (NLF) database was also used to extract data for embedded generation.
- Temperature data was sourced from the Bureau of Meteorology's (BOM) Amberley, Archerfield and Brisbane weather stations.
- The POE adjustment values are based on econometric peak demand models recalculated each season which include economic, demographic and temperature data. The resulting temperature adjusted peak demands for the Energex network are then stored in SIFT – Substation Investment Forecasting Tool.

Table 35.2 sets out the sources from which Energex obtained the required information.

Table 35.2: Information sources

Variable	Source
Raw coincident maximum demand (MW)	Metering/ NLF
Date maximum demand occurred	Metering/ NLF
Half hour time period maximum demand occurred	Metering/ NLF
Winter/Summer peaking	Metering/ NLF
Embedded generation	Metering/ NLF
Weather Corrected maximum demand 10% POE (MW)	BOM/Demand Model
Weather Corrected maximum demand 50% POE (MW)	BOM/ Demand Model

35.3 Methodology

35.3.1 Assumptions

The following assumptions apply to the data used to calculate the weather adjusted peak demand at the network level:

- The duration of the winter period is from 01 June – 31 August.
- The duration of the summer period is usually December, January and February. While the system peak demand model filtering process includes higher MW demand days in November and March, almost all of these days are subsequently eliminated due to cool temperatures (explained below). However, a seasonal peak can fall outside the defined summer period – as occurred on 5 of March 2015.
- For the winter model, any day where the average temperature (daily minimum + daily maximum / 2) was above 16.0 degrees Celsius at Amberley during the winter period – was disregarded.
- For the summer model, the weather data used was a single series population weighted composite of the Amberley, Archerfield and Brisbane weather stations. Each data point needed to satisfy two conditions, the average temperature needed to be equal or above 23.5 degrees Celsius, and the maximum temperature needed to be equal or above 30 degrees Celsius.
- The temperature data is based on the daily minimum and maximum temperatures, with the weekday, weekend and Friday temperatures all identified separately in the model, allowing both the day and temperature affects to be adjusted for.

35.3.2 Approach

Energex applied the following approach to obtain the required information:

- The Energex 2016 forecast year covers summer 2015/16 and winter 2015.
- The historical daily peak demand data was extracted from NLF database using the connection point metering. The connection point coincident demand was aggregated to the total network coincident demand based on the metering data.
- The date and time that maximum demand occurred was extracted from the NLF database. This also identified the whether the maximum demand occurred in summer or winter.
- Embedded generation data was extracted from the NLF database, based on the half hour metering data. The embedded generation included in this table are Non-scheduled generators less than 30MW in size. Estimates of the contribution of PV were also used to remove the impact of solar generation.
- The temperature adjustment process used by Energex was based on the following process:
  - The days that are unlikely to produce a peak demand were excluded.
  - Multiple seasons of data were used.
  - A multiple regression econometric model was developed to estimate coefficients for price, economic & demographic drivers, year, temperature, weekdays and the Christmas shut down period.
  - The demand - variable relationship was used in the Monte Carlo simulation to determine the 10POE and 50POE adjustments for the total Energex network. The 10POE and 50POE adjustment factors are stored against each season for each zone substation. At present, Energex is yet to implement the temperature adjustment process at the Bulk supply substation level, however the methodology will be the same as used at the zone substation level.
- The Energex System level POE values will be different from the temperature corrected figures calculated at the individual Connection Point (or Zone Substation level) and aggregated to form a system total number - as the aggregated numbers are not only based on peaks from either the summer or the winter, but there are also differences in the methodology of temperature correction, with the POE methodology used at the Energex System level incorporating more explanatory variables - like economic and demographic drivers.

35.4 Estimated Information

No Estimated Information was reported.

35.4.1 Justification for Estimated Information

Not applicable.

35.4.2 Basis for Estimated Information

Not applicable.

36. BoP 5.4.1 - Maximum Demand and Utilisation Spatial

The AER requires Energex to provide the following information relating to Table 5.4.1 – Non-Coincident and Coincident Maximum Demand:

For each sub-transmission and zone substation in the network:

- **Substation Rating – Normal Cyclic Rating**
- **Raw Adjusted maximum demand, in MW and MVA**
- **Date and time of maximum demand**
- **Whether maximum demand occurred in winter or summer**
- **10POE Weather adjusted maximum demand, in MW and MVA**
- **50POE Weather adjusted maximum demand, in MW and MVA**

All figures reported are Actual Information.

36.1 Consistency with CA RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 36.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In RIN tables 5.4.1 and 5.4.2 (on Regulatory Template 5.4), Energex must input maximum demand information for the indicated network segments. Energex must insert rows into the Regulatory Templates for each component of its network belonging to that segment. Energex must note instances where it de-commissions components of its network belonging to that segment in the basis of preparation document(s).	Information on maximum demand was provided in accordance with this requirement.
For the ‘Winter/Summer peaking’ line item, the Energex is to indicate the season in which the raw maximum demand occurred by entering ‘Winter’ or ‘Summer’ as appropriate.	Demonstrated in section 36.3.2 (Approach)
Where the seasonality of Energex’s maximum demand does not correspond with the form of its regulatory years, Energex must explain its basis of reporting maximum demand in the basis of preparation. For example, if Energex forecasts expenditure on a financial year basis but forecasts maximum demand on a calendar year basis because of winter maximum demand, Energex would state that it reports maximum demand on a calendar year basis and describe, for example, the months that it includes for any given	Demonstrated in section 36.3.2 (Assumptions)

Requirements (instructions and definitions)	Consistency with requirements
regulatory year.	
Where maximum demand in MVA occurred at a different time to maximum demand in MW, Energex must enter maximum demand figures for both measures at the time maximum demand in MW occurred. In such instances, Energex must enter the maximum demand in MVA in the basis of preparation, noting the regulatory year in which it occurred.	Demonstrated in section 36.3.2 (Approach)
If Energex cannot use raw unadjusted maximum demand as the basis for the information it provides in RIN table 5.4.1, it must describe the methods it employs to populate those tables.	Demonstrated in section 36.3.2 (Approach)
Energex must input the rating for each element in each network segment. For Regulatory Templates 5.4.1 and 5.4.2, rating refers to normal cyclic rating. a) Energex must provide the seasonal rating that corresponds to the time of the raw adjusted maximum demand. For example, Energex must provide the summer normal cyclic rating of the network segment if the raw adjusted maximum demand occurred in summer. Where Energex does not keep and maintain connection point rating information (for example, where the TNSP owns the assets to which such ratings apply), it may estimate this information or shade the cells black.	Demonstrated in section 36.3.2 (Approach)
Energex must provide inputs for ‘Embedded generation’ if it has kept and maintained historical data for embedded generation downstream of the specified network segment and/or if it accounts for such embedded generation in its maximum demand forecast. a) Energex must allocate embedded generation figures to the appropriate element of the network segment under system normal conditions (consistent with the definition of raw adjusted maximum demand). b) Energex must describe the type of embedded generation data it has provided. For example, Energex may state that it has included scheduled, semi-scheduled and non-scheduled embedded generation in the tables for connection points. In this example, we would be able to calculate native demand by adding these figures to the raw adjusted maximum demand figures. If Energex has not kept and maintained historical data for embedded generation downstream of the specified network segment, it may estimate the historical embedded generation data or shade the cells	Demonstrated in section 36.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
black. For the Regulatory Years including and after 2015 Energex must provide embedded generation data. It must do similarly if it accounts for embedded generation in its system level maximum demand forecast.	
Energex must provide inputs for the appropriate cells if it has calculated historical weather corrected maximum demand. a) Energex must provide a short description of its weather correction process in the basis of preparation document(s). Energex must describe whether the weather corrected maximum demand figures provided are based on raw adjusted maximum demand or raw unadjusted maximum demand or another type of maximum demand figure. Where Energex does not calculate weather corrected maximum demand it may estimate the historical weather corrected data or shade the cells black. For Regulatory Years 2015 and thereafter Energex will be required to provide weather corrected maximum demand on an ongoing basis in accordance with best regulatory practice weather correction methodologies.	Demonstrated in section 36.3.2 (Approach)
Tables requesting system coincident data are referring to the demand at that particular point on the network (e.g. zone substations) at the time of system (or network) peak. a) For example, Regulatory Template 5.4.2 (on Regulatory Template 5.4) requests information about the maximum demand on zone substations at the time of system or network peak. b) Conversely, non-coincident data is the maximum demand at a particular point on the network (which may not necessarily coincide with the time of system peak). For example, Regulatory Template 5.4.1 (on Regulatory Template 5.4) requests information about non-coincident maximum demand at zone substations. In Regulatory Template 5.4.1 (on Regulatory Template 5.4), Energex must provide information about the maximum demand at each zone substation in each year, which may not correspond to demand at the time of system peak. If Energex does not record and/or maintain spatial maximum demand coincident to the system maximum demand, Energex must provide spatial maximum demand coincident to a higher network segment. Energex must specify the higher network segment to which the lower network segment is coincident to in the basis of preparation document(s). For example, if Energex does not maintain maximum demand data for zone substations coincident to the system maximum demand, Energex may provide maximum demand data coincident to the connection point. In this example, Energex would specify the	Demonstrated in section 36.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
relevant connection point in the basis of preparation document(s).	

36.2 Sources

- The SIFT database was used to extract Non-coincident and coincident peak demands for the last five years for each zone and Bulk Supply substation in the Energex area of supply. The date and time of the peak demands were also extracted from the SIFT database.
- The SIFT database is linked to the Energex SCADA networks and extracts the half hour substation directly from this network.
- Temperature data was extracted from five Bureau of Meteorology (BOM) sites across Energex – Amberley, Maroochydore Airport, Brisbane Airport, Archerfield and Coolangatta.
- Embedded generation is metered directly and can be added or deleted from the attached zone substation as required. The embedded generation data is extracted from the Network Load Forecasting (NLF) database.
- The POE adjustment values were extracted from the SIFT database where they exist (progressively updating historical values using a consistent approach).
- Substation rating data was extracted from SIFT and the Equipment Rating (ERAT) database and was based on the limiting factor i.e. Transformers, cables or circuit breakers.

Table 36.2 sets out the sources from which Energex obtained the required information.

Table 36.2: Information sources

Variable	Source
Substation Rating	ERAT / SIFT
Raw adjusted maximum demand (MW)	SIFT / SCADA
Raw adjusted maximum demand (MVA)	SIFT / SCADA
Date maximum demand occurred	SIFT / SCADA
Half hour time period maximum demand occurred	SIFT / SCADA
Winter/Summer peaking	SIFT / SCADA
Adjustments – Embedded generation	NLF

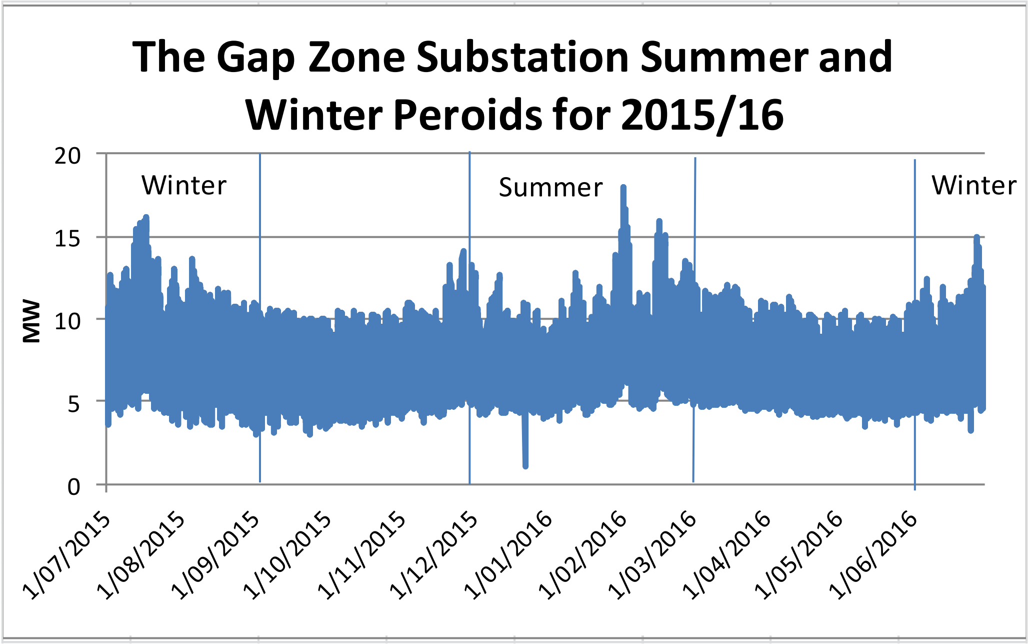
Variable	Source
Weather Corrected maximum demand 10% POE (MW)	SIFT / SCADA / BOM
Weather Corrected maximum demand 10% POE (MVA)	SIFT / SCADA / BOM
Weather Corrected maximum demand 50% POE (MW)	SIFT / SCADA / BOM
Weather Corrected maximum demand 50% POE (MVA)	SIFT / SCADA / BOM

36.3 Methodology

36.3.1 Assumptions

Energex applied the following assumptions to the data used to calculate the weather adjusted data at the zone substation level:

- Where the zone substation has insignificant variables or contribution to demand, these values were excluded from the calculation.
- The duration of the winter period is June, July and August.
- The duration of the summer period is usually December, January and February. However, when a seasonal peak falls outside the defined summer period (as occurred on 5 March 2015), the seasonal data is extended to include the peak.
- Graph 1, provided as an example, illustrates the half hourly MW load for an Energex zone substation during the 15/16 year. It demonstrates that the loads peaked in February 2016 (which was within the summer period), and hit winter seasonal peak late Jul-15 (within the defined winter period). There were no peaks above the seasonal peaks outside those two periods in the 15/16 year. Therefore, they are consistent with what AER requires.



Graph 1 - Half Hourly MW Load in the Gap Zone Substation in 15/16 Year

- The temperature threshold was based on the average for each day.
- Any day where the average temperature at Amberley was above 16.0 degrees Celsius during the winter period was disregarded.
- Any day where the average temperature at Amberley was below 23.5 degrees Celsius during the summer period was disregarded.
- The temperature data was based on the daily minimum and maximum temperatures, with the weekday, weekend and Friday temperatures all identified separately in the model, allowing both the day and temperature affects to be adjusted for.
- The weather data sourced from the Bureau of Meteorology was based on five weather stations, including Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley.
- Energex system peak half hour for winter and summer was used to determine the time and date for Coincident demand at the zone and bulk supply substations.

36.3.2 Approach

Energex applied the following approach to obtain the required information:

- Substation rating data was extracted from the SIFT database and the ERAT database. The rating was the normal cyclic rating which corresponds to the end of the season in which the raw adjusted maximum demand peaked. The Normal Cyclic rating is the maximum permissible peak daily loading for the given load cycle that a transformer can supply under normal conditions each day of its life, through summer and winter ambient temperature, without reducing the designed life of the transformer. Normal conditions is described as the system state where all plant are configured in its intended operational state, without planned or forced outages on any plant item.

- The historical demand data stored in SIFT was extracted from the SCADA system for each substation and stored as raw recorded data. Adjustments were then made based on temporary switching or situations where the network was not in a normal state. These adjustments also accounted for embedded generation to produce a native demand for each substation for day and night for each season. Energex uses adjusted raw maximum demand values for the RIN.

- For substations where it was identified that the non-coincident MVA occurred at a different time to the non-coincident MW, a separate table is attached showing the non-coincident peak demand in MVA. Refer to Appendix 7 – Maximum Demand and Utilisation Spatial – Peak MVA Differing from Peak MW.

- Non-coincident and coincident MVA values were stored based on the recorded MW and MVA compensation operating at the half hour of peak demand. The time and date of each peak was recorded in SIFT for each substation and season (I.e. summer or winter).

- The peak values recorded for 2016 are based on the greater of the historical maximum demand for the summer of 2015/16, and the historical maximum demand for the winter of 2015.

- Substations without ratings are customer substations.

- Embedded generation is stored separately based on the metering data and the substation or bulk supply substation parent. The embedded generation within Energex is generally small in size and is Non-scheduled generation including Rocky Point (the largest in the Energex area of supply).

The temperature adjustment process used by Energex was based on the following process and is documented in the Energex procedure document 674:

- The days that are unlikely to produce a peak demand were excluded.

- Multiple seasons of data were used and then normalised to remove annual growth.

- A multiple regression model was developed for daily maximum demand incorporating maximum temp, minimum temp, and variables for Fridays, Weekdays and the Christmas shut down period. D = f (MIN, MAX, Weekday, Xmas Shutdown, Fridays, constant and error term).

- The model and weather station with the best fit was used in the Monte Carlo simulation to determine the 10POE and 50POE adjustments for each zone substation. The adjustments were applied to the raw peak demand to calculate the 10POE and 50POE adjusted demands.

The 10POE and 50POE adjustment factors are stored against each season for each zone substation.

Table 36.3 provides details of decommissioned Sub-transmission Substations

Table 36.3: Decommissioned Sub-transmission Substations

Sub-Station	Year
Australian Paper Mill	2013
Airport Link Kedron (Construction)	2011
Airport Link Toombul (Construction)	2012
Amberley (Old)	2009
Currumbin Package	2009
Ebbw Vale T1- T2	2010
Ebbw Vale T4, T5 – T6	2010
North South Bypass Tunnel	2009

36.4 Estimated Information

No Estimated Information was reported.

36.4.1 Justification for Estimated Information

Not applicable.

36.4.2 Basis for Estimated Information

Not applicable.

37. BoP 6.3.1- Sustained Interruptions

The AER requires Energex to provide the following information relating to Table 6.3.1:

- **Sustained Interruptions to Supply (from 01 July 2015 to 30 June 2016)**

Actual Information was provided for all figures.

These variables are a part of Regulatory Template 6.3 – Sustained Interruptions

37.1 Consistency with Reset RIN Requirements

Table 37.1 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 37.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Sustained interruption data by Asset Category must be reported against the "Reason for Interruption" outage cause table in CA RIN sheet 6.3 Sustained Interruptions. This data is inclusive of planned events.	Reporting uses actual recorded outage data and is in accordance with this template.
SAIDI (System Average Interruption Duration Index) is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the total number of Distribution Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less).	SAIDI is provided in accordance with the template and includes all outages resulting in an interruption to customer supply that occurs for greater than one minute.
SAIFI (System Average Interruption Frequency Index) is the total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).	SAIFI is provided in accordance with the template and includes all outages resulting in an unplanned interruption to customer supply that occurs for greater than one minute.
Asset customers by category calculated in accordance with the AER method of an averaged customer base using the customers on the first and last days of the reporting period are required for the calculation of SAIDI and SAIFI.	Asset customers by category are calculated in accordance with the AER mandated method.
The MED status of each sustained event must be identified in table 6.3.1	The MED status for each day is identified in table 6.3.1
In completing table 6.3.1, Energex must select a reason from the list provided for in column F and a detail reason from the list provided in column G.	Energex has complied with the Reason and Detail Reason table of 6.3 Sustained Interruptions.

37.2 Sources

Table 37.2 sets out the sources from which Energex obtained the required information.

Table 37.2: Information sources

Variable	Source
All Asset outage data	PON/EPM
Customer base used for all reporting	PON/EPM

37.3 Methodology

- Energex utilised data in the corporate reporting system EPM (Energex Performance Management) for all outage and asset data. Outage data was queried with cause and this was matched to the AER supplied Reason and Detail Reason fields.

37.3.1 Assumptions

Energex applied the following assumptions to obtain the required figures:

- In classifying each asset failure Energex used the cause table “Reason for interruption” and “Detailed reason for interruption” and cross referenced these criteria to the Energex outage cause codes in use.
- Energex at the point of reporting could not define the detail reason of “Animal nesting/burrowing, etc. and other” therefore any animal related outage is reported against the “Animal Impact” or “Other” detail reasons.
- “Unallocated” Transformers (Transformers with Null category assigned) are not able to be assigned to a feeder and are therefore not included in the data reported. For unplanned interruptions this accounted for Sustained unplanned CML of 128,961 and a customer affected count of 1446 resulted. This equates to a system SAIDI 0.09 minutes and a system SAIFI of 0.00103 interruptions. For planned outages there were 148 outages where the associated category was unavailable. This resulted in a CML of 554,798 and a CI of 1666. This equates to a system SAIDI 0.39 minutes and a system SAIFI of 0.00119 interruptions. These “Unallocated” Transformers do not materially affect the accuracy of the data reported at a feeder level.

37.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Queried EPM to retrieve all interruptions to supply by transformer. Associated fields such as category, duration, cause and customer counts were also recorded.

2) The MED field was updated in accordance with the Energex NFM Outage Exception table which details those days that were deemed to be MED's. The days excluded were:

- 29 Nov 2015
- 10 Dec 2015
- 24 Jun 2016

3) Energex has for the CA RIN performed the 2.5 Beta calculation method to determine the appropriate threshold for daily system SAIDI.

37.4 Estimated Information

No Estimated Information was reported.

37.4.1 Justification for Estimated Information

Not applicable.

36.4.3 Basis for Estimated Information

Not applicable.

Appendix 1 – Balancing Items

Table 2.1.1 - Standard control services capex

Balancing item is made up of:	Actual ($) 2016
Material oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - Logistics and stores (POW Material Management)	-5,276,206.3
Fleet oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet	-10,310,731.0
Total balancing item per above	**-15,586,937.4**

Table 2.1.2 - Standard control services opex by category

Balancing item is made up of:	Actual ($) 2016
Material oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - Logistics and stores (POW Material Management)	-476,182.8
Fleet oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet	-5,708,362.3
Non-network costs - included in Template 2.6 Non-network as opex and Template 2.10 Overheads	-169,475,925.1
Total balancing item per above	**-175,660,470.2**

Table 2.1.3 - Alternative control services capex

Balancing item is made up of:	Actual ($) 2016
Material oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - Logistics and stores (POW Material Management)	-714,799.1
Fleet oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet	-834,106.7
Connection capex reported twice in 2.5 Connections as well as 4.3 Fee Based Services and 4.4 Quoted Services	-4,875,955.0
Total balancing item per above	**-6,424,860.7**

Table 2.1.4 - Alternative control services opex

Balancing item is made up of:	Actual ($) 2016
Material oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - Logistics and stores (POW Material Management)	-250,303.6
Fleet oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet	-1,428,153.7
Metering opex - captured in Template 4.2 Metering and in the Template 4.3 Fee-Based Services	-714,807.0
Special meter reading double counted - reported in Template 4.2 Metering and Template 2.5 Connection	-1,839,234.1
Public Lighting double counted - reported in 4.1 Public Lighting as well as 4.3 Fee Based Services and 4.4 Quoted Services	-1,426,852.8
Connections double counted - reported in 2.5 Connections as well as 4.3 Fee Based Services and 4.4 Quoted Services	-18,167,055.0
Metering double counted - reported in 2.10 Network Overheads as well as 4.2 Metering	-7,417,402.0
Total balancing item per above	**-31,243,808.1**

Appendix 2 – Reconciling Items

RECONCILIATION FROM CA RIN SUMMARY NUMBERS TO ANNUAL PERFORMANCE RIN TO AUDITED STATUTORY ACCOUNTS			
		2016	
	CAPEX	OPEX	TOTAL
	$	$	$
Template 2.1 Summary Numbers			
SCS	555,301,203.1	348,687,622.2	903,988,825.2
ACS	45,477,530.6	81,982,328.7	127,459,859.3
TOTAL from Template 2.1	600,778,733.7	430,669,950.9	1,031,448,684.6
Adjusted for:			
• Relocation of assets excluded from Template 2.5 Connections in accordance with the definition of "connections expenditure" but included in the Annual Performance RIN	4,202,576.9	-	4,202,576.9
• Customer Requested Meter installation CAPEX included in Template 4.2 Metering and associated overhead in Template 2.10 Overhead in accordance with CA RIN definition but excluded in the Annual Performance RIN as they are funded by the customer and is not added to the relevant asset base for regulatory purposes	(17,422,193.1)	-	(17,422,193.1)
• Network Asset Rearrangement CAPEX included in Template 4.4 Quoted Services and associated overhead in Template 2.10 Overhead in accordance with CA RIN definition but excluded in the Annual Performance RIN as they are funded by the customer and is not added to the relevant asset base for regulatory purposes	(3,851,215.9)	-	(3,851,215.9)
• ACS Connections CAPEX (excluding gifted asset) included in Template 2.5 Connections and associated overhead in Template 2.10 Overhead in accordance with CA RIN definition but excluded in the Annual Performance RIN as they are funded by the customer and is not added to the relevant asset base for regulatory purposes	(7,270,994.5)		(7,270,994.5)
• Large customer connections and subdivision funded by customers which when gifted to Energex are included in SCS Capex as Capital Contributions and reported in AP RIN table 8.2.1 but excluded from CA RIN Template 2.5 Connections	55,692,842.6	-	55,692,842.6
• Adjustments made for the Annual Performance RIN that don't appear in the source information for the relevant regulatory templates	(16,543.5)	(52,280.4)	(68,823.9)
• A portion of non-network CAPEX (direct costs only) included in the table 2.1.1 Standard control services capex relates to non network expenditure incurred but allocated to non-regulated services per Energex's CAM. This allocation is excluded in the Annual Performance RIN	(898,484.4)		(898,484.4)
Annual Performance RIN	631,214,721.7	430,617,670.5	1,061,832,392.2
Adjusted for:			
• TUOS	-	433,560,433.1	433,560,433.1
• Finance costs	-	309,002,428.0	309,002,428.0
• Depreciation, amortisation & impairment	-	435,232,631.3	435,232,631.3
• Jurisdictional Scheme Payment	-	187,078,396.8	187,078,396.8
• Non-regulated services	42,456,429.0	55,562,333.9	98,018,762.9
Add back:			
• Expenditure excluded in accordance with Annual Performance RIN requirements but included in the statutory account	32,331,399.1	-	32,331,399.1
Audited Statutory Accounts - Consolidated	706,002,549.8	1,851,053,893.5	2,557,056,443.3
CAPEX calculation from statutory account			
Property, Plant & Equipment			
- Additions (Work in Progress)	670,523,862.4		
- Captalised interest (Work in Progress)	6,915,922.4		
Intangible assets			
- Additions (Work in Progress)	28,562,765.0		
	706,002,549.8		

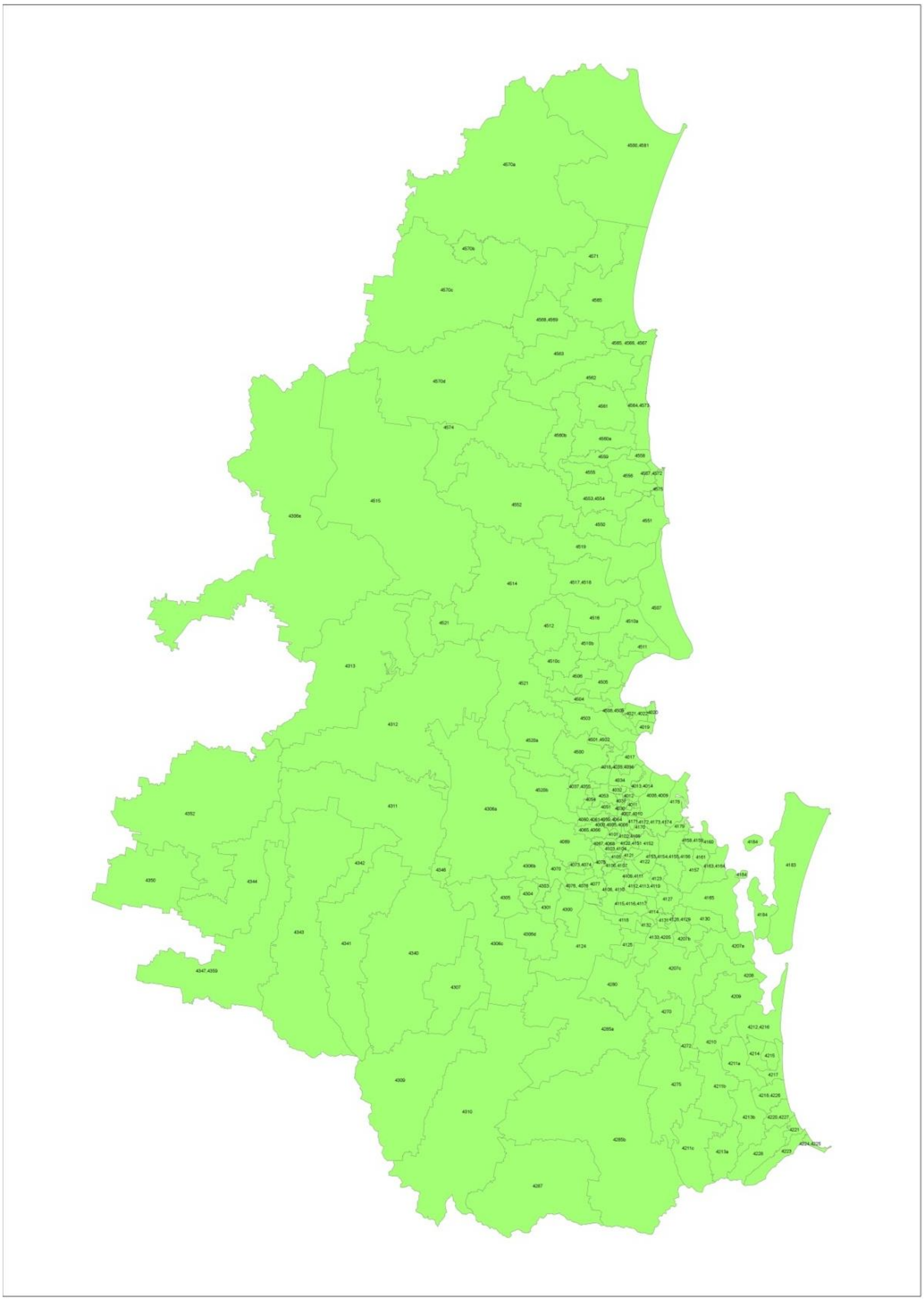
Appendix 3 – Mapping Table

Mapping Table

CA RIN Categories vs Annual Performance RIN Categories (Capex by Purpose)

Service Classification	Reset CA RIN Categories	Annual Performance RIN (Capex by purpose)
Network		
Standard Control	Replacement	Asset Replacement
Standard Control	Connections	Connections and customer-initiated works
Standard Control	Augmentation	Augmentation
Alternative Control	Connections	ACS Connection Services
Alternative Control	Metering	ACS Metering Services
Alternative Control	Fee based services	Ancillary network services – fee based
Alternative Control	Quoted services	Ancillary network services – quoted
Alternative Control	Public lighting	ACS public lighting
Non-network		
Non-network excluding Control Centre - SCADA	Non-network	Non-network, ACS public lighting, ACS Metering, ACS Connections, Ancillary network services

Appendix 4 – Vegetation Management Zones Map



Appendix 5 – Cost Element Mapping to Input Table Categories

Reset RIN Input Table Category	Cost Element Hierarchy	Cost Element examples *(not an exhaustive list)*
Direct Material Cost	Energy Related Cost of Sales	Electricity Purchases (including Solar PV FiT payments) QCA Levy ESO Levy
	Materials	Stores issues Workwear Direct purchases
	Other Cost of Sales	Customer incentive payment
Direct Labour Cost	Employee Benefits	Ordinary time Overtime Labour hire Annual leave Long service leave Sick leave Workers compensation Superannuation Payroll tax Study assistance Redundancy payments Staff bonus
Contractor Cost	Contractors	Contractors – operations Contractors – professional services Legal professional services
	Consultants	Consultants
	SPARQ Solutions Charges	SPARQ Solutions SLA SPARQ Solutions asset usage fee
Other Cost	Occupancy Expense	Rent and leases Rates Electricity and gas Repairs and maintenance Cleaning Waste Security
	Transport	Fleet management fees Fuel and oils Registration and insurance

Reset RIN Input Table Category	Cost Element Hierarchy	Cost Element examples *(not an exhaustive list)*
		Scheduled maintenance Accident repairs Vehicle hire Car parking and tolls
	Marketing	Advertising Direct marketing
	Other operating expenses	Audit fees Customer compensation Stationery Postage and couriers Subscriptions Bank fees

Appendix 6 – Explanation of functional areas

Network Overhead

Network Overhead costs refer to the provision of network, control and management services that cannot be directly identified with specific operational activity (such as routine maintenance, vegetation management, etc.).

For distribution NSPs, Network Overhead includes the following:

- management (not directly related to any of the functions listed below);
- network planning (i.e. system planning);
- network control and operational switching personnel;
- quality and standard functions including standards & manuals, asset strategy (other than network planning), compliance, quality of supply, reliability, and network records (e.g. geographical information systems (GIS));
- project governance and related functions including supervision, procurement, works management, logistics and stores; and
- Other including training, OH&S functions, network billing and customer service & call centre.

In addition to the above, Network Overhead includes:

- Meter reading;
- Advertising/marketing;
- Guaranteed Service Level (GSL) payments;
- Demand side management (DSM) expenditure/ non-network alternatives; and
- Levies.

Management – includes all costs associated with general management of the network business, i.e. management and management support staff not directly involved with any other network overhead functions (i.e. network planning, network control and operational switching personnel, quality and standard function, project governance and related functions, training, network billing and customer service and call centre). This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and is incurred within the Energex areas identified below. It also includes the non-bookable time associated with team briefs, meetings, etc.

- Asset Management Office - responsible for the development and management of strategies, policies, and procedures associated with managing the distribution network.

- Mains Design and Power System Engineering – responsible for the provision of engineering design services and solutions for infrastructure.

Network Planning – includes all costs associated with developing visions, strategies or plans for the development of the network. This includes functions such as demand forecasting, network analysis, preparation of planning documentation, area plans, and the like, as well as management directly associated with these functions. This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and incurred within the following Energex areas:

- Network Capital Planning – responsible for preparing and monitoring demand and energy forecasts to produce the capital development program for the network as well as preparing business cases and approvals for major project augmentation of the transmission sub-transmission and distribution networks;

- Demand and Risk Management – responsible for demand side management and program of work optimisation to enable control and management of risks on the Energex network; and

- Environment - undertakes environmental risk and compliance activities, performs environmental assessments (e.g. environmental requests, contaminated land, national parks, fauna, and vegetation), and manages sustainability (e.g. recycling and carbon footprint).

Network Control and Operational Switching Personnel - Includes all costs associated with network control (system operations). This includes functions such as planning and scheduling of switching activities, control room staff, management of field crews, dispatch operators, associated support staff, as well as management directly associated with these functions. This function also includes all costs associated with field crews that undertake the operational switching of the network to facilitate network access or restoration, as well as any directly associated local management that is not included in the Network Control category. Costs are principally incurred within the following Energex areas:

- Network Operations - responsible for: network alarm monitoring and response; customer telephone response; trouble call management and after hours dispatch; disaster coordination; network load management; network supply standards and consulting services; planned and emergency network access and network control.

- Control and Secondary Systems – responsible for the building, installation, commissioning and maintenance of SCADA and telecommunications services to the distribution network.

Quality and Standard Functions - Includes all costs associated with management of the quality of supply, supply reliability, etc. It also includes all costs associated with the development, maintenance and compliance with network technical standards, service standards, quality of supply standards, etc. This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and incurred within the following Energex areas:

- System Engineering and Operational Technology and Telecommunications – responsible for the provision of technical standards for the electricity and telecommunications networks, technical specifications and tender evaluations for network plant and materials, protection engineering services and network design solutions.

- Network Asset Management Group – responsible for the development and implementation of asset management strategies and plans through an integrated CAPEX/OPEX POW, to achieve financial and non-financial targets, in conjunction with resource groups.

- Network Property Data and Coordination – responsible for ensuring ongoing and access to accurate network data through providing strategic initiatives around systems and processes that support the Network business in the management of adherence to standards.

Project Governance and Related Functions - Includes all costs associated with the approval and management control of network projects or programs. This includes the cost of functions such as project management offices, works management, or project control groups where these costs are not directly charged to specific projects or programs. This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and is incurred in four areas:

- Supervision – This function is accountable for oversight of the delivery of program of work.

- Procurement – This function includes all activities associated with the identification and implementation of 'Best Practice' procurement strategies that contribute to Energex's overall business objectives including achieving value for money and ensuring probity and accountability for outcomes.

- Works Management – This function includes all activities required to ensure that the Network Program of Work is established and delivered according to network priorities, budget and by making the best use of available resources.

- Logistics and Stores (POW Material Management) – this function is responsible for storing and handling materials used in Energex’s Program of Work (POW). These costs are also treated as materials on costs in accordance with Energex’s AER-approved CAM.

OHS – Includes expenditure associated with safety and specialist post and pre-trade training such as cable jointing and safety courses to staff

Customer Services – Includes all costs associated with activities arising from specific requests by customers that requires work on the Energex network. It includes:

- Attending to and resolving loss of supply and cold water complaints, and other miscellaneous network related concerns raised by customers
- Ground inspections of overhead service connections
- Assessment of meters, relays and CTs to ensure compliance with standards
- Costs associated with payments to customers on account of Energex failing to meet agreed service level standards
- Call centre costs

Network Billing and Other Energy Market Services (including meter reading) - This function encompasses all activities associated with metering including the reading of meters, data storage and network billing.

Metering function comprises two main activities, being metering operations and energy market roles:

- Metering Operations - involves the role of official Responsible Person (RP) for Energex, the regulatory and compliance role for metering and a focus on metering systems, new technology and equipment including systems integration and metering strategy.
- Energy Market Roles includes: Metering Data Agency (MDA) and Meter Data Provider (MDP) involving the collection, validation, substitution, processing, reporting and delivery of meter data to AEMO and relevant market participants in accordance with the National Electricity Rules.
- Network Billing is responsible for the calculation of network distribution use of system (DUOS) charges at the NMI level, aggregation of accounts to a retailer level and publication of a statement of charge to each NEM retailer monthly.

Demand Side Management (DSM) Initiatives - This function encompasses activities associated with the development and implementation of a range of initiatives to manage customer demand. It also includes the expenditure associated with the Demand Management Innovation Allowance (DMIA) funding.

Corporate Overhead

Corporate Overhead costs refer to the provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity.

Corporate overhead costs typically include those for executive management, legal and secretariat, human resources, finance, and other corporate head office activities.

- Office of CEO - Provides leadership to position Energex as a safe, efficient, environmentally sustainable and commercial organisation.

- Legal and Secretariat - is responsible for the management of legal issues, legal advice and litigation and provision of legal support to economic regulation issues and bodies.
- Audit - Provision of assurance over effectiveness of Internal Control.
- Strategy and Regulation – Includes costs incurred within the following areas:
  - Corporate Governance Management Office - Responsible for the development and management of a corporate governance framework, including governance policies, to foster assurance of Energex's system for ethics and integrity.
  - Regulatory Affairs - Manages the regulatory determination, ensures compliance with regulatory obligations and is the interface between Energex and Regulators
  - Corporate Risk and Compliance – Responsible for the development, establishment and implementation of a corporate risk management framework and approach and compliance program to manage Energex business risk and associated management and Board reporting.
  - Corporate Strategy and Planning - Develops and deploys Energex's strategic direction, corporate and business planning, strategic policies and corporate sustainability.
  - Revenue Strategy - develop and deploy revenue and pricing strategies which optimise outcomes of the regulatory revenue reset process and secures Energex's future funding requirements.
- Human Resources - Resourcing and recruiting, new starter information, day to day people leadership and HR activities, payroll information processing, training and development, health and wellbeing and internal communication.
- Finance – Includes costs incurred within the following areas:
  - Financial Control - is responsible for the provision of financial and regulatory reporting (e.g. financial statements, RIN financial information, management of external audit, monthly financial reporting, balance sheet, Ellipse finance)
  - Taxation - is responsible for the management of Energex's tax risk compliance and tax advice (e.g. GST, Fringe Benefit Tax, Payroll Tax, and Income Tax).
  - CFO Management Office - provides commercial and financial oversight to Energex.
  - Business Performance and Analysis and Treasury - Provides Group and Divisional financial reporting, budgeting, forecasting, Investment Review Committee governance and business case management. It also undertakes balance sheet, Fitch Credit Review and guarantee register functions.
- Business Support Services – delivers a range of administrative and support services including accounts payable, accounts receivable, corporate insurance, records and information management.

- Business Operations and Performance – responsible for delivering current operational performance, building capability for the delivery of future performance and managing risk.
- Field Support Services - Includes costs incurred within the following areas:
  - Field Support Management Office
  - Generator Services - provision of generation services as network support during outages required for the performance of maintenance activities
  - Tools and Equipment Operations - supply, manage, test and maintain Energex field equipment and associated services
  - Laboratory Services - calibration and testing of Energex equipment
- Stakeholder Engagement and Management – Includes costs incurred within the following areas:
  - Customer Advocacy - is responsible for the management of relationships with customers encompassing customer communication, complaints and community liaison.
  - Government Relations - is responsible for handling escalated customer complaints and enquiries from Energy and Water Ombudsman, Minister's Office, State and Federal MP's, OGOC and Government Departments and Government Briefing Notes.
  - Corporate Communications - This function involves the management of media relations, community consultation and internal communications (excluding sponsorships). The function also includes the maintenance and enhancement of corporate marketing requirements, including brand, research, marketing communications and website communications (e.g. emergency information) and investing to build stronger community partnerships in line with Energex strategy (e.g. advertising and community education about safety and demand management).
- Property - This function is responsible for ensuring Energex sites are efficient, effective, safe and green. Responsibilities include security, facility maintenance, property acquisitions and disposals, lease and licence management, and compliance reporting audits.
- Fleet - The indirect costs associated with operating and maintaining Energex's leased or owned vehicles, (excluding depreciation and amortisation) that are used in the construction, operation or maintenance of the electricity network. These costs are also treated as fleet oncosts in accordance with Energex's AER-approved CAM.

Appendix 7 – Maximum Demand and Utilisation Spatial – Peak MVA Differing from Peak MW.

Abermain BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		85.43
			MAX MVA		86.00
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		16/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		17:30
			MAX MVA		20:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Algester BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		67.11
			MAX MVA		70.34
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		29/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:30
			MAX MVA		14:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Ashgrove West BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		68.94
			MAX MVA		74.16
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		03/06/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		17:30
			MAX MVA		20:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		WINTER
Beaudesert BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT	31.46	
			MAX MVA	33.82	
	DATE MD OCCURRED		NON-COINCIDENT	15/07/2015	
			MAX MVA	11/12/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	18:30	
			MAX MVA	20:00	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	SUMMER	
Ibis BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT	15.13	
			MAX MVA	19.38	
	DATE MD OCCURRED		NON-COINCIDENT	03/07/2015	
			MAX MVA	30/07/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	18:30	
			MAX MVA	08:00	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Meeandah BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		46.76
			MAX MVA		50.95
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		18/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		10:30
			MAX MVA		13:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER

Postmans Ridge BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT	36.51	
			MAX MVA	37.67	
	DATE MD OCCURRED		NON-COINCIDENT	16/07/2015	
			MAX MVA	03/06/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	21:30	
			MAX MVA	21:30	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Runcorn BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		49.86
			MAX MVA		49.88
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		29/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:30
			MAX MVA		14:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Sandgate BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		79.49
			MAX MVA		79.51
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		18:30
			MAX MVA		19:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Stradbroke Is BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT	10.56	
			MAX MVA	22.60	
	DATE MD OCCURRED		NON-COINCIDENT	03/08/2015	
			MAX MVA	03/06/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	17:30	
			MAX MVA	20:00	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Sunrise Hills BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		72.04
			MAX MVA		72.07
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		17:30
			MAX MVA		17:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Victoria Park BS	RAW ADJUSTED MD	MVA	NON-COINCIDENT		49.03
			MAX MVA		55.96
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		23/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:30
			MAX MVA		14:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER

Acacia Ridge	RAW ADJUSTED MD	MVA	NON-COINCIDENT		19.56
			MAX MVA		21.76
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		29/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:30
			MAX MVA		14:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Ann St	RAW ADJUSTED MD	MVA	NON-COINCIDENT		42.97
			MAX MVA		43.60
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		01/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:00
			MAX MVA		13:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Archerfield	RAW ADJUSTED MD	MVA	NON-COINCIDENT		21.03
			MAX MVA		23.38
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		04/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:00
			MAX MVA		09:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Bald Hills Bus 1	RAW ADJUSTED MD	MVA	NON-COINCIDENT		9.91
			MAX MVA		10.82
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		17/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:00
			MAX MVA		10:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Bald Hills Bus 2	RAW ADJUSTED MD	MVA	NON-COINCIDENT		12.59
			MAX MVA		15.87
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		29/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:00
			MAX MVA		19:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Booval	RAW ADJUSTED MD	MVA	NON-COINCIDENT		21.70
			MAX MVA		21.71
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		16/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		17:30
			MAX MVA		17:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Brendale	RAW ADJUSTED MD	MVA	NON-COINCIDENT		32.06
			MAX MVA		32.18
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		18:30
			MAX MVA		18:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER

Brighton	RAW ADJUSTED MD	MVA	NON-COINCIDENT		9.86
			MAX MVA		11.36
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:00
			MAX MVA		19:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Bundamba	RAW ADJUSTED MD	MVA	NON-COINCIDENT		36.32
			MAX MVA		36.33
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		03/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:00
			MAX MVA		18:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Carpendale	RAW ADJUSTED MD	MVA	NON-COINCIDENT		1.59
			MAX MVA		1.74
	DATE MD OCCURRED		NON-COINCIDENT		18/02/2016
			MAX MVA		12/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		20:00
			MAX MVA		20:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Cleveland	RAW ADJUSTED MD	MVA	NON-COINCIDENT		21.87
			MAX MVA		22.12
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		18:00
			MAX MVA		18:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Cooneana	RAW ADJUSTED MD	MVA	NON-COINCIDENT		3.40
			MAX MVA		3.59
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		25/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		18:00
			MAX MVA		07:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Crestmead	RAW ADJUSTED MD	MVA	NON-COINCIDENT		22.18
			MAX MVA		22.59
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		14:30
			MAX MVA		11:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Eight Mile Plains Bus 1	RAW ADJUSTED MD	MVA	NON-COINCIDENT		14.50
			MAX MVA		19.07
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		21/07/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		16:30
			MAX MVA		07:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		WINTER

Fisherman Is A	RAW ADJUSTED MD	MVA	NON-COINCIDENT	11.10	
			MAX MVA	11.11	
	DATE MD OCCURRED		NON-COINCIDENT	03/07/2015	
			MAX MVA	01/07/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	19:00	
			MAX MVA	17:30	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Gympie	RAW ADJUSTED MD	MVA	NON-COINCIDENT		23.82
			MAX MVA		23.85
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		01/12/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		16:30
			MAX MVA		15:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Hamilton	RAW ADJUSTED MD	MVA	NON-COINCIDENT		20.09
			MAX MVA		20.21
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		14:30
			MAX MVA		16:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Hamilton Lands	RAW ADJUSTED MD	MVA	NON-COINCIDENT		12.71
			MAX MVA		13.26
	DATE MD OCCURRED		NON-COINCIDENT		18/02/2016
			MAX MVA		11/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:30
			MAX MVA		11:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Helidon	RAW ADJUSTED MD	MVA	NON-COINCIDENT		3.20
			MAX MVA		5.16
	DATE MD OCCURRED		NON-COINCIDENT		17/02/2016
			MAX MVA		25/08/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:30
			MAX MVA		11:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		WINTER
Hendra	RAW ADJUSTED MD	MVA	NON-COINCIDENT		17.74
			MAX MVA		17.75
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		16:30
			MAX MVA		16:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Holland Park	RAW ADJUSTED MD	MVA	NON-COINCIDENT		21.87
			MAX MVA		21.88
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		01/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:30
			MAX MVA		19:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER

Ibis	RAW ADJUSTED MD	MVA	NON-COINCIDENT		0.27
			MAX MVA		3.78
	DATE MD OCCURRED		NON-COINCIDENT		03/02/2016
			MAX MVA		03/06/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:00
			MAX MVA		18:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		WINTER
Imbil	RAW ADJUSTED MD	MVA	NON-COINCIDENT	2.20	
			MAX MVA	2.72	
	DATE MD OCCURRED		NON-COINCIDENT	15/07/2015	
			MAX MVA	03/06/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	06:30	
			MAX MVA	07:30	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Innisplain	RAW ADJUSTED MD	MVA	NON-COINCIDENT	3.99	
			MAX MVA	4.05	
	DATE MD OCCURRED		NON-COINCIDENT	18/07/2015	
			MAX MVA	18/07/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	18:30	
			MAX MVA	20:00	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Kawana	RAW ADJUSTED MD	MVA	NON-COINCIDENT		30.39
			MAX MVA		30.40
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		14:30
			MAX MVA		13:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Kedron	RAW ADJUSTED MD	MVA	NON-COINCIDENT		25.47
			MAX MVA		28.22
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		19:30
			MAX MVA		13:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Lytton B	RAW ADJUSTED MD	MVA	NON-COINCIDENT		16.65
			MAX MVA		18.75
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		14/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:30
			MAX MVA		10:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Makerston St	RAW ADJUSTED MD	MVA	NON-COINCIDENT		65.13
			MAX MVA		65.17
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		01/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:00
			MAX MVA		13:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER

Mango Hill Bus 2	RAW ADJUSTED MD	MVA	NON-COINCIDENT		25.55
			MAX MVA		25.59
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		16:30
			MAX MVA		16:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Marburg	RAW ADJUSTED MD	MVA	NON-COINCIDENT		3.30
			MAX MVA		3.54
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		16/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		16:00
			MAX MVA		15:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Mt Tamborine Bus 2	RAW ADJUSTED MD	MVA	NON-COINCIDENT	8.81	
			MAX MVA	13.35	
	DATE MD OCCURRED		NON-COINCIDENT	17/07/2015	
			MAX MVA	19/06/2015	
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT	18:30	
			MAX MVA	18:30	
	WINTER/SUMMER PEAKING		NON-COINCIDENT	WINTER	
			MAX MVA	WINTER	
Murrumba	RAW ADJUSTED MD	MVA	NON-COINCIDENT		1.98
			MAX MVA		2.65
	DATE MD OCCURRED		NON-COINCIDENT		22/01/2016
			MAX MVA		02/12/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:00
			MAX MVA		10:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Nth Pine Dam	RAW ADJUSTED MD	MVA	NON-COINCIDENT		0.89
			MAX MVA		1.02
	DATE MD OCCURRED		NON-COINCIDENT		11/02/2016
			MAX MVA		20/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		09:00
			MAX MVA		11:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Oxley	RAW ADJUSTED MD	MVA	NON-COINCIDENT		18.67
			MAX MVA		18.93
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		29/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:00
			MAX MVA		13:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Parkwood	RAW ADJUSTED MD	MVA	NON-COINCIDENT		14.43
			MAX MVA		14.93
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		29/01/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		17:00
			MAX MVA		12:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER

Salisbury	RAW ADJUSTED MD	MVA	NON-COINCIDENT		15.89
			MAX MVA		16.31
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		01/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:00
			MAX MVA		13:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Somerset Dam	RAW ADJUSTED MD	MVA	NON-COINCIDENT		0.37
			MAX MVA		0.50
	DATE MD OCCURRED		NON-COINCIDENT		13/01/2016
			MAX MVA		27/12/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		20:00
			MAX MVA		20:00
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Spring Creek	RAW ADJUSTED MD	MVA	NON-COINCIDENT		4.21
			MAX MVA		4.33
	DATE MD OCCURRED		NON-COINCIDENT		17/02/2016
			MAX MVA		17/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		13:30
			MAX MVA		14:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Sunnybank	RAW ADJUSTED MD	MVA	NON-COINCIDENT		25.00
			MAX MVA		95.97
	DATE MD OCCURRED		NON-COINCIDENT		29/01/2016
			MAX MVA		19/07/2015
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		14:30
			MAX MVA		07:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		WINTER
Victoria Park	RAW ADJUSTED MD	MVA	NON-COINCIDENT		36.38
			MAX MVA		38.03
	DATE MD OCCURRED		NON-COINCIDENT		02/02/2016
			MAX MVA		02/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		11:00
			MAX MVA		10:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Whiteside	RAW ADJUSTED MD	MVA	NON-COINCIDENT		7.55
			MAX MVA		8.27
	DATE MD OCCURRED		NON-COINCIDENT		17/02/2016
			MAX MVA		16/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		16:30
			MAX MVA		16:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER
Yandina	RAW ADJUSTED MD	MVA	NON-COINCIDENT		5.70
			MAX MVA		5.82
	DATE MD OCCURRED		NON-COINCIDENT		01/02/2016
			MAX MVA		01/02/2016
	HALF HOUR TIME PERIOD MD OCCURRED		NON-COINCIDENT		17:00
			MAX MVA		16:30
	WINTER/SUMMER PEAKING		NON-COINCIDENT		SUMMER
			MAX MVA		SUMMER