Energex

Category Analysis RIN
Basis of Preparation

2014/2015

energex

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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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.

2.1 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 2.6, 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.
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 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 (b) Account for any differences arising due to the reporting of capex on a basis other than the "as-incurred" basis.	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. 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	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.

Requirements (instructions and definitions)	Consistency with requirements
(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.	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 Regulatory Accounting Statements to the Audited Statutory Accounts.

2.2 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 year’s regulatory accounting statements and/or supporting work papers (regulatory accounting numbers), 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 regulatory reconciliation is provided in **Appendix 2 – Reconciling Items** and reconciles:

- Capex from the regulatory accounting statements to additions to Work in Progress from the audited statutory accounts; and
- Opex from the regulatory accounting statements to total expenses from the audited statutory accounts.

2.3 Methodology

The methodology for calculating balancing and reconciling items is detailed in section 2.3.2 Approach.

2.3.1 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 2015.
- 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.

2.3.2 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 – 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 Testing – also captured in Template 2.10 Overheads as Network Overheads – Customer Service and in Template 4.3 Fee Based Services as Meter Test;

  - Meter Investigation – also captured in Template 2.10 Overheads as Network Overheads – Customer Service and in Template 4.3 Fee-Based Services as a Meter Test and Meter Inspection;
  - Scheduled Meter Reading – also captured in Template 2.10 Overheads as Network Overheads – Customer Services;
  - Special Meter Reading – also captured in Template 4.3 Fee-Based Services as Off-cycle Meter Reads; and
  - Meter Maintenance – also captured in Template 2.10 Overheads as Network Overheads – Customer Service and in Template 4.3 Fee-Based Services as alterations and additions to current metering equipment.

- 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 regulatory accounting 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 regulatory accounting numbers.

- Items which are excluded from (or included in) the relevant regulatory templates in accordance with the definitions, but are included in (or excluded from) the regulatory accounting numbers.

- Gifted assets which are excluded from the relevant regulatory templates in accordance with the relevant definitions but are included in the regulatory accounting numbers.

- Adjustments made for the regulatory accounting numbers that do not appear in the source information for the relevant regulatory templates. These are typically for:
  - accruals entries not processed to the individual projects until the actual expenditure is recorded
  - entries identified after balance date

- Network Overheads and Corporate Overheads for ACS, which are not included in Regulatory Template 2.1 but are included in the regulatory accounting numbers.

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

Table 1.2: Approach to obtaining regulatory accounting numbers

Table 2.1.1 - Standard control services capex	Actual ($ nominal)
	2015
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 regulatory accounts.
Replacement expenditure	Directly from the annual regulatory accounts.
Connections	
Augmentation Expenditure	
Non-network	Annual regulatory accounts and/or supporting workings. Control Centre - SCADA direct costs are included in repex as explained above.
capitalised network overheads	Annual regulatory accounts and/or supporting workings
apitalised corporate overheads	Annual regulatory accounts 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 regulatory accounts
capcons	Annual regulatory accounts

Table 2.1.2 - Standard control services opex by category	Actual ($ nominal)
	2015
Vegetation management	Directly from the annual regulatory accounts
Maintenance	Directly from the annual regulatory accounts; includes Inspection and Planned Maintenance. Breakdown into Inspection and Planned Maintenance is obtained from the data supporting the annual regulatory accounts
Emergency response	Directly from the annual regulatory accounts; includes Corrective Repair and Emergency Response from the annual regulatory accounts. Breakdown into Inspection and Planned Maintenance is obtained from the data supporting the annual regulatory accounts
Non-network	Sum of opex totals from table 2.6 Non-network as non-network opex summary numbers are not available from the annual regulatory accounts
network overheads	Annual regulatory accounts and/or supporting workings
corporate overheads	Annual regulatory accounts and/or supporting workings
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL OPEX	Annual regulatory accounts

Table 2.1.3 - Alternative control services capex	Actual ($ nominal)
	2015
Connections	For the current Determination period, Energex does not have ACS Connections Assets
capitalised network overheads	Annual regulatory accounts and/or supporting workings
apitalised corporate overheads	Annual regulatory accounts and/or supporting workings
Metering	For the current Determination period, Energex does not have ACS Metering Assets
Public lighting	Directly from annual regulatory accounts
Fee and quoted	
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL CAPEX	Annual regulatory accounts

Table 2.1.4 - Alternative control services opex	Actual ($ nominal)
	2015
Connections	For the current Determination period, Energex has no Alternative Control Services connections.
network overheads	Annual regulatory accounts and/or supporting workings
corporate overheads	Annual regulatory accounts and/or supporting workings
Metering	Annual regulatory accounts and/or supporting workings
Public lighting	Directly from annual regulatory accounts
Fee and quoted	
balancing item	Numbers included more than once in the regulatory templates. Refer to the separate balancing items.
TOTAL OPEX	Annual regulatory accounts

2.4 Estimated Information

No Estimated Information was reported.

2.4.1 Justification for Estimated Information

Not applicable.

2.4.2 Basis for Estimated Information

Not applicable.

2.5 Explanatory notes

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

2.6 Accounting policies

Energex changed its accounting policy in 2014/15 with respect to regulated revenue under and over recoveries. Previously, Energex accrued or deferred allowed regulated revenues through recognising the full amount of revenue allowed under its revenue determination and recognising any under (or over) recovery of this amount as an asset (or liability) to be adjusted in future revenues to be received from customers.

2.6.1 Nature of the change

There is no definitive guidance on the accounting treatment for regulatory receivables or provisions within existing accounting standards. However the Australian Accounting Standards Board (AASB) has commented, in response to the International Accounting Standards Board's (IASB) *Invitation to Comment ITC32 Reporting the Financial Effects of Rate Regulation*; that it has a view that, in most cases, regulatory deferral account balances do not meet the asset and liability recognition criteria as contained in the AASB's *Conceptual Framework*. To date, consensus has not been achieved and divergent views continue to be debated by the IASB.

The new policy, where the accrued (or deferred) revenues are not recognised, results in more reliable and relevant information to users as it reflects a closer correlation between market conditions, shareholder and other regulatory policies and profitability.

2.6.2 Impact of the change

As regulated revenue under (or over) recoveries are no longer recognised in the Statutory Accounts the treatment is in line with the Regulatory reporting.

There is no impact on expenditure reported.

2. BoP 2.2.1 - Repex Expenditure

The AER requires Energex to provide actual expenditure values and replacement volumes for the 2014/15 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.**

Estimated 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.

3.1 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

Requirements (instructions and definitions)	Consistency with requirements
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”.	Demonstrated in section 3.5 - Explanatory notes

Requirements (instructions and definitions)	Consistency with requirements
In instances where Energex considers that both the prescribed asset 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.	Demonstrated in section 3.5 - 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 8 – 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.

3.2 Sources

- The key data sources used to produce figures for replacement expenditure and asset replacement volumes were EPM, SIFT, Ellipse, Report Explorer, Planning Approval Reports, project scope statements and project estimates and network program project commissioning 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	EPM
	Pole top structures	EPM
	Overhead conductors	EPM
	Underground cables	EPM
	Service lines	EPM

	Variable	Source
	Transformers	EPM
	Switchgear	EPM
	Public lighting	EPM
	SCADA, network control and protection systems	EPM
Volume of asset replacements	Poles	EPM, Planning approval reports, SIFT, C20 Program of Work List.
	Pole top structures	EPM
	Overhead conductors	EPM, Planning approval reports, SIFT, C20 Program of Work List.
	Underground cables	EPM, Planning approval reports, SIFT, C20 Program of Work List.
	Service lines	EPM
	Transformers	EPM, SIFT, C20 Program of Work List, Planning approval reports, network program project commissioning reports
	Switchgear	EPM, SIFT, C20 Program of Work List, Planning approval reports, network program project commissioning reports
	Public lighting	EPM
	SCADA, network control and protection systems	EPM, SIFT, C20 Program of Work List, Planning approval reports

3.3 Methodology

3.3.1 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.

- Asset replacement volumes for plant items (C2025, C2040 and C2065) are based on the project commissioning date. Due to the short cycle nature of distribution projects, asset replacement volumes for distribution items (C2540 and C2545) are based on material transaction dates.

- 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.

- Asset replacement volumes for Service Lines also include a planned/dedicated replacement program captured under financial activity C2570 and NAMP line CA12.
- For each project that was analysed as part of RIN table 2.2.1, Energex has calculated a value of the 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 project expenditure to Repex asset categories.
- 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”.
- In relation to the asset group “SCADA, Network Control and Protection Systems”, if a substation circuit breaker or transformer was replaced, it was assumed that protection relays and Local Wiring Asset associated with the asset were replaced.

3.3.2 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:

Step 1 – Replacement project data extraction

- A report was run from EPM Business Objects which listed all replacement projects that incurred expenditure in the 2014/15 regulatory year under the replacement financial activity codes detailed in Table 2.3 below:

Table 2.3 – Replacement financial activity codes

Activity Code	Description
C2025	ART Asset Replacement - 11KV Network
C2040	ART Asset Replacement - Subtransmission
C2065	ART Asset Replacement - SCADA / Telecoms
C2540	ARD Ageing Assets
C2545	ARD Pole Reinstatement & Pole Nailing

- This report provided a list of all transactions incurred on replacement projects over the period, with the exception of replacement volumes relating to the pole nailing activity.

Step 2 – Analysis of materials expenditure transactions

- Life to date material transaction records were used to allocate expenditure to the Repex asset categories for all projects that had expenditure in 2014/15. The open projects are discussed in Step 6 below.

- Once a list of replacement project transactions was identified, detailed analysis was undertaken of the materials costs associated with each transaction. The purpose of this analysis was to assign each unique material cost to an appropriate Repex asset category. Establishing a relationship between material costs and Repex asset categories provided a basis for allocating total project expenditure across Repex asset categories (discussed in Step 5).

- This mapping process was undertaken by:
  - Identifying a subset of material cost transactions to be mapped to Repex asset categories. Due to the large volume and type of materials transactions, Energex constrained its analysis to the define AER RIN Asset Categories; and
  - Allocating each material cost transaction to a Repex asset category, based on the stock code associated with the material where available.
  - Manually mapped expenditure with no AER RIN Asset Category stock code to an asset category based on project description.

Step 3 – Aggregation of expenditure values and replacement volumes at the project level

- Following the analysis of materials costs, a separate summary table was created listing each project identified under Step 1 with the following information:
  - Total expenditure incurred on each project. Expenditure at the project level was based on the summation of each transaction relevant to the project.
  - The volume of materials associated with each project, disaggregated by Repex asset category. This information was sourced from the analysis of material undertaken in Step 2.
  - Materials expenditure associated with each project, disaggregated by Repex asset category. This was sourced from the analysis of materials undertaken in Step 2.
  - Total expenditure associated with each project, disaggregated by Repex asset category, as a percentage of total Repex material expenditure for the project (that is, a weighted average of materials expenditure).

Step 4 – Material cost and volume adjustments

Pole nailing

- Pole nailing projects were included in the extract from EPM, however, pole nailing is performed by contractors and the volume of materials used are not captured as in the same manner as the other asset categories. Therefore, the volume of pole nailing undertaken by each replacement project was captured through a separate EPM physicals report and these volumes were entered as a manual adjustment across the relevant Repex asset categories.

SCADA, Network Control and Protection Systems

- As some of the equipment used in the SCADA, Network control and Protection systems is not sourced via Energex's stores system, in order to determine the expenditure values and asset volumes of communications 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.

- Both the replacement volumes and expenditure was mapped to a Repex asset category and input as a manual adjustment.

Step 5 – Allocation of project expenditure to Repex asset categories

- To allocate project expenditure across each Repex asset category, the project expenditure was applied to the weighted average materials expenditure associated with the Repex asset category1. This provided an estimate of project expenditure by Repex asset category.

- The project expenditure allocated to each Repex asset category was then summated across all projects to provide an overall estimate of the expenditure for each Repex asset category. These values were then input to RIN table 2.2.1.

An example is provided below to illustrate how the process of allocation occurs.

Example:

Consider a project which incurred $10 million of expenditure in 2014/15.

Assume that the project used three types of material which were mapped to the Repex asset categories outlined below. In this example, the cost of materials summed to $4 million, meaning that $6 million of other costs (labour, contractors and other costs needed to be allocated across Repex asset categories – refer to Table 2.4:

[1] This included the data collected under Step 3 and Step 4

Table 2.4 – Project expenditure example (b)

Repex asset category	Cost of materials ($m)	Percentage of total materials cost
Poles: > 132 kV; WOOD	$0.5	12.5%
Underground cables: > 132 kV	$1.5	37.5%
Transformers: POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA	$2	50%
Total cost of materials	***$4***	***100%***

The total project cost allocated to a particular Repex asset category is calculated as the product of total expenditure for the year and the percentage of total materials cost for that Repex asset category. This calculation is outlined in Table 2.5:

Table 2.5 – Project expenditure - total expenditure calculations

Year	Repex asset category			***Total project expenditure by year***
	Poles: > 132 kV; WOOD	**Underground cables: > 132 kV**	**Transformers: POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA**	
2014/15	$1.25 ($10 x 12.5%)	$3.75 ($10 x 37.5%)	$5 ($10 x 50%)	*$10*

Step 6 – Allocation of remaining projects

- The remaining open projects used issued stock values and forecasts of major plant items to allocate expenditure to the Repex asset categories. The volumes of assets were determined through a review of project documentation including Planning Approval Reports, scope statements and project estimates.
- Open project with no issued or forecast stock items were manually assigned to an AER RIN Asset Category.

Step 7 – Data consolidation

- The replacement expenditure of both sets of projects (with and without material transactions) were consolidated and entered into RIN table 2.2.1.

Step 8 – 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.

3.4 Estimated Information

All data is Estimated Information due to the judgements that were made during the categorisation of expenses and quantities.

3.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN table 2.2.1. As such Energex had to manually categorise each into the categories required.

SCADA, Network Control and Protection Systems

- Energex made the assumption that if a substation circuit breaker or transformer was replaced associated protection relays were replaced. Local Network Wiring assets were also assumed to be replaced with transformers and circuit breakers.

- The rationale for this assumption and associated estimate was on the basis that project scope documentation did not go down to a level of detail necessary to identify replacement volumes for low cost items.

3.4.2 Basis for Estimated Information

- Each cost and quantity was manually categorised using multiple descriptors within the data. For full details refer to the approach section above.

3.5 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

- Planned service line replacement programs have been included and categorised as Repex activities in 2014/15. The expenditure for this program was captured under C2570 for 2014/15 and would have normally been mapped to the Connections template 2.5. Service line replacement quantities include number of services replaced under the planned program (NAMP line CA12), as well as apportioned material booked out under normal Repex activities.

The Planned service line replacement expenditure and quantities (NAMP line CA12) which has been remapped to the Repex template is as follows:

- 14/15 Units: 21,610
- 14/15 Expenditure: $16,783,511

- Public lighting replacement programs included a mixture of replacement and augmentation projects. They are detailed in Regulatory Template 4.1 Public Lighting.
- 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.

Other asset categorisation

- Energex identified expenditure in 14/15 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 Materials". This expenditure covers replacement of the following assets:
  - NER
  - OHEW
  - Planned Batteries
  - Instrument Transformers
  - Insulators
  - Meter 1
  - Meter 2
  - General Other
  - Non AER Material >1kV <= 11kV Capacitor
- The annual expenditure allocated to "Other Non AER Materials" in the Repex model for the 2014/15 regulatory year was $9,061,236.51.

Differences between last CARIN (2013/14 data from Submission) VS 2014/15 CARIN methodology

- More stock codes mapped

- Change of AER Category of previous year stock codes (e.g. LV service cable was previously mapped to Overhead Conductor)

Old Methodology

Asset Group	Count of Stock Code
Overhead Conductor	37
Pole Top Structures	31
Poles	35
Public Lighting	135
Switchgear	140
Underground Cable	60
Transformers	97
Scada/Protection	92
Grand Total	**627**

Other	Count of Stock Code
Materials - Other	4506
Grand Total	**4506**

New Methodology

Asset Group	Count of Stock Code
Poles	51
Switchgear	681
Pole Top Structures	92
Public Lighting	181
Underground Cable	66
Overhead Conductor	30
Transformers	429
Services	4
Scada/Protection	217
Grand Total	**1751**

Other	Count of Stock Code
Materials - Other	10163
Grand Total	**10163**

- Allocation of 2014/15 expenditure was apportioned based upon the total life to date materials for a Project not just the materials purchased in 2014/15. This may result in no physicals recognised in 2014/15 but an apportionment of expenditure (e.g. “Pole Top>66kV<=132kV”). Also, if no life to date material purchases an apportionment was based upon the estimated stock items in the in-progress estimate with a construction or construction warehouse flag. Furthermore, if no stock items identified with issued or estimate stock items a manual allocation was performed to map to an AER category. Any stock items which mapped to the AER category “Other Other Materials” were ignored in the allocation of expenditure.

3. BoP 2.2.2 - Repex Asset Failures by Category

The AER requires Energex to provide asset failure volumes for the 2014/15 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**

Estimated Information was supplied for Public Lighting variables.

Actual Information was provided for all other components of submitted data.

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

4.1 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 4.3 (Methodology)

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

4.2 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	Focal Point (PON)
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
SCADA	Ellipse

4.3 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.

4.3.1 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.

4.3.2 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 2014-15"). 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 01/07/2014 to 30/06/2015 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 01/07/2014 to 30/06/2015 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 01/07/2014 to 30/06/2015 was extracted from the source system (PON) data using FocalPoint. The resultant excel exports were placed in the central working folder and summated in a single spreadsheet. 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 01/07/2014 to 30/06/2015. 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 01/07/2014 to 30/06/2015. 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 street light luminaires and lamps, asset replacement volumes have been 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. (A failure of a street light pole is contained under Poles Failures.)

Public Lighting Failures - Luminaires and Lamps

- Energex does not report asset failure data for street light luminaires and lamps. The information provided in template 2.2 for luminaires and lamps reflects the volume of luminaires and lamps replaced as part of Energex's three street light maintenance contracts (C-08042 SL Patrols, C-07018 SL Repair and Construction and C-10214 SL Maintenance, Construction and Patrols6).

- Whilst some of the replacements will be based on asset failures, this information is not reported in Energex's systems. The information below steps out how this information was obtained:
  - A project work order transaction report was run from Report Explorer ELL00159 against the work orders relevant to the public lighting three public maintenance contracts (that is, 3482304, 3482365 and 3482366) for 2014/15.

- This report detailed all expenses against each of the maintenance projects.
- A detailed analysis was then done on each expense line item to determine the volume of luminaires and lamps used for maintenance. This process of asset identification, which was performed by material stock code, also identified for each luminaire and lamp, whether is it was for a major road or a minor road.
- The number luminaires and lamps (by major road and minor road) was then summed together to provide a proxy for the total annual value for asset failures.

Public Lighting Failures - Brackets

- The volume of 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 2014/15 regulatory year.

4.4 Estimated Information

All Public Lighting information reported in RIN table 2.2.1 is Estimated Information.

4.4.1 Justification for Estimated Information

Energex does not capture the Public Lighting information required.

4.4.2 Basis for Estimated Information

For a description of the methodology for Public Lighting Estimated Information please refer to the section 4.3 (Methodology) above.

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

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 with a value of (153,305 of 603,269 poles)
- The pole data does include poles without a spatial location with a value of (1,621 of 603,269 poles).

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 NFM 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 classicisation 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)	*2014/15*
TOTAL MVA REPLACED	331
TOTAL MVA DISPOSED OF	237.5

4.3.2 Approach

Energex applied the following approach to obtain the required information:

Asset Volumes Currently in Commission

Total Poles By: Feeder Type

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2014/15 (30/6/2015) and stored in the schema RIN.
    a. Current feeder categories were used to determine the feeder category as a number of data corrections happened post EOF 2014/15 period which needed to be applied to the data.
    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 run from the RIN and SEN schema using the script FeederPoleCategory_2015_v01_01.sql:
    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 (153,305 Poles in total)
3) Results were extracted to Excel file Pole_Feeder_Cat_2015_V01_00.CSV
4) Overhead routes were assigned feeder categories based snapshot taken at the end of the financial year 2014/15.
    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)

b. The poles data without a spatial location with a value of (1,621 of 603,269 poles) were prorated within the filled groups.

5) Poles from Pole_Feeder_Cat_2015_V01_00.CSV are Spatial joined to the Routes

a. Poles and the routes were spatial 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) Core NFM tables were denormalised, a snapshot taken as at the end of the financial year 2014/15 (30/6/2015) and stored in the schema RIN.

2) An extract was run from the RIN schema using the script FeederCategory_2015_v01_00.sql:

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	0.13
Urban	3.47
Rural	4.71

3) Information was extracted to Excel file CatLineLength_v01_00.xls.

4) Within Excel file conductors with an unknown category (333.69 km) were pro-rated into categories CBD, Urban and Rural based on existing ratios.

Conductors Category	*Percentage*	*Quantity (km)*
CBD (High-Density)	0.06%	0.18
Rural	61.83%	206.32

Conductors Category	*Percentage*	*Quantity (km)*
Urban	38.12%	127.19

Overhead Conductor By: Conductor Length Material Type

1) Core NFM tables were denormalised, snapshot taken as at the end of the financial year 2014/15 (30/6/2015) and stored in the schema RIN as tables Conductor_Age_2015 and SEGMENT_CUSTOMER_2015.

2) An extract was run from the RIN schema using the script ConductorType_2015_v01_00.sql

   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 the data has not be 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)*
AAAC	0.1
HDBC	1.53
ACSR	4.08
AAC	2.78

   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 (3.85km / 0.01% 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.

Estimated ABC Cable	*Quantity(km)*
LV ABC	3151.63
HV ABC	40.93

3) Information was extracted to Excel file LineTypeLength_v01_00.xls.

4) 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

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

6) Within the Excel file, conductors with an unknown conductor type (25.6 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 ratios.

Conductors Category	*Percentage*	*Quantity (km)*
Steel	2.44%	0.625895163
Conductor ABC	8.98%	2.298414284
AAAC	0.47%	0.119768486
HDBC	19.26%	4.93212425
AAC	47.92%	12.26829649
ACSR	20.93%	5.357881327

Underground Cables by: Cable Length by Feeder Type

1) Core NFM tables were denormalised, snapshot taken as at the end of the financial year 2014/15 (30/6/2015) and stored in the schema RIN.

2) The Extract was run from the RIN schema using the script FeederCategory_2014_v01_00.sql

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	0.22
Urban	19.02
Rural	2.46

3) Information was extracted to Excel file CatLineLength_v01_00.xls.

4) Within Excel file cables with an unknown category (16.16 km) were pro-rated into categories CBD, Urban and Rural based on existing ratios.

Cables Category	*Percentage*	*Quantity (km)*
CBD (High-Density)	1.23%	0.20
Rural	30.35%	4.9
Urban	68.42%	11.06

Transformer By: Total MVA

1) Core NFM tables were denormalised, a snapshot taken as at the end of the financial year 2009/10 to 2014/15 and stored in the schema RIN.

2) An extract was run from the RIN schema using the script Capacity_Transformer_v01_00.sql from the years 2009/10 to 2014/15.

3) Current Capacity was the summation of all known Rated Outputs for the end of financial year 2014/15.

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 2014/15 is spread between CBD, Urban; and Rural short poles based on the volumes currently in service.

3) Energex was required to add overhead conductor material types. Energex broke down the assets by OH Conductor ABC, OH conductor Steel, OH conductor ACSR, OH conductor AAAC, OH conductor AAC, OH conductor HDBC

Transformer By: Total MVA

1) Core NFM tables were denormalised, a snapshot taken as at the end of the financial year 2009 to 2015 and stored in the schema RIN.

2) An extract was run from the RIN schema using the script Capacity_Transformer_v01_00.sql from the years 2009 to 2015.

3) Information was extracted into individual Excel files: TX_yyyy_v03_01.xls (yyyy = year of extract).

4) Excel files were consolidated into excel file TX_Combined_v03_01.xls.

5) Within the Excel file the transformers were compared to previous year to determine disposal and replacement MVA quantities for Distribution as follows:
   a. The previous year asset was compared to the asset installed in the relevant year and if the assets were different it was deemed to be a replacement.
   b. The rated output of the asset from the previous year was deemed to be the disposal value.
   c. The rated output of asset in the relevant year was deemed to be the replacement value.

6) Data was gathered on Power Transformers replaced throughout the financial year.
   a. The rated output of the asset from the previous year was deemed to be the disposal value

b. The rated output of asset in the relevant year was deemed to be the replacement value.

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.
- Transformers By: Total MVA

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

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.

4.4.2 Basis for Estimated Information

Replacement volume for the specific asset groups was based on the total volume of asset replaced in RIN table 2.2.1. RIN table 2.2.1 only included assets that were replaced under Repex projects; therefore it is the most reliable source for asset replacement volumes as per the AERs definitions.

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 2014/15):

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

These figures form part of Regulatory Template 2.3 – Augex

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 for Augex expenditure figures. Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.
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.	Please refer to sections 5.3.1 Assumptions and Section 5.4.1 Justification for Estimated Information.
Energex must not include information for gifted assets.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
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	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.

Requirements (instructions and definitions)	Consistency with requirements
party contracts' and 'Other expenditure – Civil works' columns.	
Energex must not include augmentation information relating to connections in this Regulatory Template.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information for further information.
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 the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information for further information.
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	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.

Requirements (instructions and definitions)	Consistency with requirements
close occurred in the years specified in the penultimate row in the table, as indicated.	
Energex must 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.	
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. (i) 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	(d) Please refer to section 5.3.2 - Approach – Voltage (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 (l) Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.

Requirements (instructions and definitions)	Consistency with requirements
and tertiary voltages, respectively. (k) 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. (l) 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.	
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. (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 (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. (g) Where Energex chooses 'Other - specify' in a drop down list, provide details in the basis of preparation. (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. (i) For 'Project ID', input Energex's identifier for the project. This may be the project name, location and/or code. (j) For 'Project trigger', choose the primary trigger for the project from the drop down list. Describe	(d) Please refer to section 5.3.2 - Approach – Voltage (e) Data has been entered in accordance with instructions (f) Please refer to (g) Please refer to section 5.3.2 - Approach - project type (h) Please refer to section 5.3.2 - Approach Line ID (i) Please refer to section 5.3.2 - Approach Project ID (j) Please refer to section 5.3.2 - Approach – Project triggers (k) Please refer to section 5.3.2 - Approach – Route Line Length Added

Requirements (instructions and definitions)	Consistency with requirements
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. (k) For length metrics, 'km added' refers to the gross addition of the relevant length measure resulting from the augmentation work: (i) 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.	
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.	Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.
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.	Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.
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.	Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.
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.	Please refer to BoP 2.3.2 - Augex Subtransmission Cost metrics for further information.

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, SIFT
Route Line Length Added	Engineering Specification, Feasibility Study, Project Scope Statement, GIS, Simulation Models(verification only)
Substation ID	SIFT, Project Approval Report
Substation Type	SIFT, ERAT2
Voltage	SIFT, ERAT2
Line ID	ERAT2, 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 plant rating methodologies used in the planning approval report.
- Post-project rating information is based on current plant rating methods.
- All ratings are based on summer conditions.
- All newly established zone substations have no pre-project ratings.

- Feeder works within the boundary of the substation are not included as part of RIN table 2.3.2 for sub-transmission lines.
- Substation projects consisting of a total feeder works for a certain voltage level is less than 500m route length 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 5.6.
- 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.
- Only projects with total project expenditure greater than $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 2014/15:
  - C0017124
  - C0065199
  - C0065215
  - C0076665
  - C0103936
  - C0112576
  - C0113238

Substation ID

- The details of which substation is augmented for each project is taken from either 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)
C0112576	110	C0065215	110
C0113238	33	C0112576	33
C0076665	33	C0065199	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 drivers and their descriptions can be seen in Table 5.4:

Table 5.4: Projects with Secondary Drivers

Project ID	Additional Project Triggers
C0076665	Project also addressed a voltage issue and a reliability issue.
C0017124	Project also addressed reliability issue.
C0103936	Project also had a refurbishment driver.
C0112576	The primary driver to replace the transformers was due to refurbishment needs.

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 equally proportion 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.

- Information is sourced from SIFT where the description of works for the feeder component is then verified against Energex 33kV SINCAL model, and Energex corporate GIS systems.

- 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
C0076665	New DCCT UG and New SCCT OH
C0065215	New DCCT OH
C0065199	Line rebuild, Line Upgrade , New DCCT UG and New DCCT OH

- 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 in the table below.

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 sharing capability between transformers to work out the true substation rating capability.
- Table 5.6 below details projects where transformers are removed as part of the project scopes:

Table 5.6: Substation projects which have transformers removal components

Project Number	Transformers Removed
C0103936	Removed 2x60MVA 110/33kV transformers.
C0112576	Removed 2x30MVA 110/11kV transformers.

5.4 Estimated Information

Actual Information is provided for the following columns:

- Substation ID,
- Substation Type,
- Line ID,
- Project ID,
- Project Type,
- Project Trigger; and
- Voltage.

Estimated Information is provided for the following columns:

- Substation Ratings; and
- Route Line Length Added.

5.4.1 Justification for Estimated Information

Energex did not have a system to store historical substation capacity and feeder route length. As a result, this information was obtained manually from previous planning reports and/or design documentations.

Substation Normal Cyclic and Emergency Cyclic Capacity

- The pre-project normal cyclic rating and pre-project emergency cyclic rating is sourced from previous planning approval reports.

Feeder Route Line Length Added

- Feeder upgrade projects consist of a combination of pole replacement, conductor replacement, conductor re-tensioning and 11 kV distribution feeders overbuild.
- The route line length added is obtained from engineering specification documentation where only the length of new construction is counted towards this parameter. Any upgraded feeder section by means of reconductoring or overbuilding is excluded from this but is included the “circuit km upgraded” value.

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 are a part of Regulatory Template 2.3 – Augex.

The following items in RIN table 2.3.1 are apportioned based on the value of purchased items excluding non-materials:

- Transformers – Expenditure
- Switchgear – Expenditure
- Capacitors – Expenditure
- Other Plant Item – Expenditure
- Installation (Labour) – Volume and Expenditure
- Other Expenditure
- All Related Party Contracts
- All Non Related Party Contracts
- Land And Easements

All figures in RIN table 2.3.2 are apportioned based on the value of purchased items excluding non-materials.

These variables form 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 the basis of preparation document(s).	The calculations of capacity are based on normal conditions. For the definition of normal conditions please refer to BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics.
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 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'). 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.	
Record all expenditure data on a project close basis in real	

Requirements (instructions and definitions)	Consistency with requirements
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. (i) Energex must provide any calculations used to convert real to nominal	
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: (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 (i) input the required details.	Only projects greater than $5 million nominal expenditure over the life of the project are reported.
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: (iii) 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	Data has been entered in accordance with instructions.

Requirements (instructions and definitions)	Consistency with requirements
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	
For RIN table 2.3.1: 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. 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.	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information.
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: (i) 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 development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information.
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 development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information.
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	Data has been entered in accordance with instructions.

Requirements (instructions and definitions)	Consistency with requirements
500kV is the primary voltage and 275kV is the secondary voltage. (i) 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.	
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.	Data has been entered in accordance with instructions.
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.
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 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 2014-15.
(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	Data has been entered in accordance with instructions.

Requirements (instructions and definitions)	Consistency with requirements
compensation payments.	
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	EPM P6 Project Management System

Supporting information included additional project information from the P6 project management system.

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. 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:

- Total cumulative expenditure of a project includes overhead costs as per AER clarification;
- Subtransmission lines projects greater than $5M must include a material amount of subtransmission lines works, for further details please refer to the “Project Description and Changes” Basis of Preparation;

- In RIN table 2.3.1 "other plant items" include subtransmission line materials detailed in RIN table 2.3.2;
- In RIN table 2.3.2 "other plant items" include zone and bulk supply material costs included in Table 2.3.1;
- Installation labour in RIN table 2.3.1 includes "cable installation" labour;
- Installation labour is allocated based on work group;
- Installation volume in RIN table 2.3.1 is the sum of the substation assets installed;
- Installation volume in RIN table 2.3.2 is the sum of 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 from the 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 sub-transmission 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 EPM Business Objects which listed all projects closed within the regulatory year 2014/15, under the Augex financial activity codes in Table 6.3:

Table 6.3: Augex Financial Activity Codes for Projects Transactions in 2014/15

Activity Code	Description
C2020	EIT Augmentation – Sub Transmission & Transmission
C2030	PRT Reliability & Power Quality
C2050	CWT Demand Prim Reliability Sec

Activity Code	Description
C2060	EIT Augmentation – 11kV Network
C2070	EIT Land & Right of Way
C2075	EIT Easements
C2080	CWT Community Requirements
C2095	EIT Infrastructure Projects
C2565	EID Company Initiated
C2580	EID Control & Metering (Incl. DSM)

2) This report included all Energex projects, not only those related to subtransmission. Therefore, the project list is filtered to include only those projects relating to subtransmission. This is done using the project descriptions and budget codes.

3) The extracted subtransmission project list reported each project and their total yearly expenditure broken down by direct costs and overheads as per the Energex CAM. Each project with a total (whole of life) expenditure of greater than $5 million (nominal, inclusive of direct and overhead costs) is reported as a separate project in the Regulatory Template. Those projects less than $5 million are labelled as a non-material projects to be consolidated into a single substation line item in RIN table 2.3.1 and a single subtransmission line item in RIN table 2.3.2.

4) Each project is then required to be labelled as either a substation project (for input into RIN table 2.3.1), a subtransmission lines project (for input into RIN table 2.3.2). Material projects are allocated to the respective tables based on detailed analysis of the project documentation. This allocation is based on assumptions that are documented in the “Augex – Project Description and Changes” Basis of Preparation (please note that a material project could be reported within both tables if it incorporated both substation and lines construction). Immaterial projects are allocated to either RIN table 2.3.1 or 2.3.2 based on analysis of the project descriptions.

5) This then gave the list of subtransmission projects reported.

Expenditure and Volumes

1) The total direct cost for each project reported in RIN tables 2.3.1 and 2.3.2 is then calculated using the yearly costs for each project extracted in the EPM report as stated above. In accordance with AER instructions, all expenditure data for a project close basis is reported in real dollars ($2014–15). Specifically, values must not include data for augmentation works where project close occurs after the years specified but incurs expenditure prior to this date. These yearly costs are multiplied by an escalation factor to convert the figures to $2014-15 basis. The escalation

factors are calculated from the ABS values for CPI based on the eight capital cities average, and these are found in Table 6.4:

Table 6.4: Escalation Factors

Financial Year	Escalation Factor
2014-15	1.000
2013-14	1.030
2012-13	1.055
2011-12	1.067
2010-11	1.105
2009-10	1.139
2008-09	1.155
2007-08	1.206
2006-07	1.231
2005-06	1.280
2004-05	1.312
2003-04	1.345
2002-03	1.380

2) To calculate the remaining columns in RIN tables 2.3.1 and 2.3.2 a second report is run from EPM which detailed all expenses and quantities against each of the projects.

3) Data is obtained using the materials costs against each project. Each materials expense is classified by a Stock Item Group Class (SIGC). The following SIGCs are identified as being both high value and applicable to the material breakup required in RIN tables 2.3.1 and 2.3.2:

   a. CABLE, ELECTRICAL
   b. CAPACITORS
   c. CIRCUIT BREAKERS
   d. COILS AND TRANSFORMERS
   e. CONNECTORS, ELECTRICAL
   f. ELECTRIC HARDWARE
   g. ELECTRICAL CONTROL EQUIP
   h. ELECTRICAL TEST
   i. FIXTURES AND LIGHTING
   j. FUSES
   k. INSULATORS
   l. MISC ELECTRIC POWER

m. MISC ELECTRICAL COMPONENT

n. PREFAB TOWER STRUCTURES

o. RELAYS AND SOLENOIDS

p. SWITCHES

q. WOOD POLES

4) Each stock item within these SIGCs is then analysed individually to assign them to one of the Repex asset categories classifications, which are in turn mapped to Augex asset categories.

5) Once the materials costs is classified using the stock item descriptions, the remaining expenses against each project are classified using various information assigned to each expense item.

6) Table 6.5 outlines the logic applied to group these expenses into their intermediate expense categories.

7) The classification of sub-transmission feeder materials (poles/tower and conductor) of a project, as Addition or Upgraded, has been done by analysis of the feasibility study report or the engineering specification - whichever represents the most recent information for that project. The units added or upgraded associated with the sub-transmission feeder components of a project are apportioned based on the spread of sub-transmission feeder materials outlined by the feasibility study report or the engineering specification.

Table 6.5: Logic applied to group expenses

Energex Intermediate Category	Logic Applied
Civil	• 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
Energex Labour-Instal	• Cost Category Type is 'Labour' • The work order maintenance type is Construction, Costing Work Order, Equipment Replacement, Pole Recovery, Recover Asset/Equipment, Repair Non-Storm, Replace pole, Switching Work Order, Testing/Commissioning, Vegetation Management
Energex Labour-Non Instal	All Other Energex Labour costs
Ctr-D&C	• Cost Category Type is "Contractor' • The work order maintenance type is Construction, Design
Ctr-Instal	• The cost category type is 'Contractor' • The work order maintenance type is Construction, Costing Work Order, Equipment Replacement, Manufacture, Pole Recovery, Purchase Asset, Purchase to Pay, Recover Asset/Equipment, Replace pole, Switching Work Order,

Energex Intermediate Category	Logic Applied
	Testing/Commissioning, Vegetation Management
Land	Top Project: Financial Activity Code is C2070
Easement	Top Project: Financial Activity Code is C2075
Other	All other costs

Once all costs are categorised and grouped into those required in RIN tables 2.3.1 and 2.3.2. Table 6.6 outlines the grouping of asset categories for RIN table 2.3.1.

Table 6.6: Grouping of asset categories for RIN table 2.3.1

CA RIN Category – Table 2.3.1	Asset Categories
Transformers Units Added	Quantity values within: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV>15MVA<=40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA
Transformers MVA Added	The quantity multiplied by the rating within: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV>15MVA<=40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA
Transformers	Expenses within: • TR Grd>=22kV<=33kV<=15MVA • TR Grd>=22kV<=33kV>15MVA<=40MVA • TR Grd>=22kV<=33kV>40MVA • TR Grd>33kV<=66kV>15MVA<=40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA
Switchgear Units Added	Quantity values within: • Switchgear<=11kV;CB • Switchgear>22kV<=33kV;CB • Switchgear>66kV<=132kV;CB

CA RIN Category – Table 2.3.1	Asset Categories
Switchgear	Expenses within: • Switchgear<=11kV;CB • Switchgear>22kV<=33kV;CB • Switchgear>66kV<=132kV;CB
Capacitors Units Added	Quantity values within: • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Capacitors MVAR Added	The quantity multiplied by the rating within: • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Capacitors	Expenses within: • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Other Plant Item	Expenses within 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<=40MVA • TR Grd>66kV<=132kV<=100MVA • TR Grd>66kV<=132kV>100MVA • Switchgear<=11kV;CB • Switchgear>22kV<=33kV;CB • Switchgear>66kV<=132kV;CB • Non AER Material >= 110kV Capacitor • Non AER Material >11kV <= 33kV Capacitor • Non AER Material >1kV <= 11kV Capacitor
Installation Labour - Volume	Internal actual hours booked to a project source via EPM.
Installation Labour	Expenses within: • Energex Labour-Install • Cable Installation • Ctr-Install • Ctr-D&C (33.3%)
Civil Works	Expenses within: • Civil • Ctr-D&C (33.3%)

CA RIN Category – Table 2.3.1	Asset Categories
Other Direct	Expenses within: • Energex Labour-Non Install • Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C (33.3%) • Ctr-Sparq • Other • IOB
Total Direct Expenditure	As per RIN Template
Related Party Margins	NA
Related Party Total	Expenses within: • Ctr-Sparq
All Non Related Party Contracts	Expenses within: • Civil • Cable Installation • Ctr-Install • Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C
Land Purchase	Expenses within: • Land
Easements	Expenses within: • Easements

Table 6.7 outlines the grouping of asset categories for RIN table 2.3.2.

Table 6.7: Grouping of asset categories For RIN table 2.3.1

<table>
<tr><th>CA RIN Category – Table 2.3.2</th><th>Asset Categories</th></tr>
<tr><td>Poles / Towers Added</td><td rowspan="2">Quantity values within:
• Pole>22kV<=66kV;Wood
• Pole>66kV<=132kV;Wood
Poles are allocated as either added or upgraded based on the main driver of the project</td></tr>
<tr><td>Poles / Towers Upgraded</td></tr>
<tr><td>Poles/Towers Expenditure</td><td>Expenses within:
• Pole>22kV<=66kV;Wood
• Pole>66kV<=132kV;Wood</td></tr>
</table>

CA RIN Category – Table 2.3.2	Asset Categories
Overhead Lines Expenditure	Expenses within: • OH Conductor>22kV<=66kV • OH Conductor>66kV<=132kV
Underground Cables Expenditure	Expenses within: • UG Cable>22kV<=33kV • UG Cable>66kV<=132kV
Other Plant Item Expenditure	Expenses within all other asset categories excluding: • Pole>22kV<=66kV;Wood • Pole>66kV<=132kV;Wood • OH Conductor>22kV<=66kV • OH Conductor>66kV<=132kV • UG Cable>22kV<=33kV • UG Cable>66kV<=132kV
Installation Labour - Volume	Labour spend divided by average cost per hour of Energex Labour
Installation Labour	Expenses within: • Energex Labour-Install • Cable Installation • Ctr-Install • Ctr-D&C (33%)
Civil Works	Expenses within: • Civil • Ctr-D&C (33%)
Other Direct	Expenses within: • Energex Labour-Non Install • Ctr-D&C (33%) • Other
Total Direct Expenditure	Calculated as per RIN Regulatory Template
Related Party Margins	NA
Total	As per RIN Regulatory Template.
All Non Related Party Contracts	Expenses within: • Civil • Cable Installation • Ctr-Install • Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C

CA RIN Category – Table 2.3.2	Asset Categories
Land Purchase	Expenses within: • Land
Easements	Expenses within: • Easements

6.4 Estimated Information

The following items in RIN table 2.3.1 are apportioned based on the value of purchased items excluding non-materials:

- Transformers – Expenditure;
- Switchgear – Expenditure;
- Capacitors – Expenditure;
- Other Plant Item – Expenditure;
- Installation (Labour) – Volume and Expenditure;
- Other Expenditure;
- All Related Party Contracts;
- All Non Related Party Contracts; and
- Land and Easements.

Figures in RIN table 2.3.2 are apportioned based on the value of purchased items, excluding non-materials.

6.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN tables 2.3.1 and 2.3.2. Apportionment by value of purchased items uses actual values, with the calculation translating to the quantities required.

For closed project Units:

- Project Status Closed
- Filter projects with expenditure in financial year 2014/15
- Filter projects for Augex Budget Codes
- ELLIPSE stock code AER RIN mapping table

- Calculate each stock code quantity from actual projects / Work Orders
- Based on each stock code transaction value, the project's expenditure is apportioned
- Project expenditure for 2014/15 is apportioned to the respective RIN category
- Categorise each stock code Quantity to respective AER RIN category

For opened project Units:

- Project Status Opened
- Filter projects with expenditure in financial year 2014/15
- Filter projects for Augex Budget Codes
- ELLIPSE stock code AER RIN mapping table
- Multiply Stock code unit cost x quantity to get “stock code transaction” then apply apportionment.

6.4.2 Basis for Estimated Information

Not applicable.

6.5 Explanatory notes

For Project ID C0017124, there are no transformers units added or any associated expenditure reported. This is due to the project utilising existing transformers recovered from another substation.

7. BoP 2.3.3 - Augex Distribution

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.
Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables).	The calculations of capacity are based on normal conditions. For the definition of normal conditions please refer to Basis of Preparation 2.3.1.
Energex must not include information for gifted assets.	No gifted assets are included.

Requirements (instructions and definitions)	Consistency with requirements
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.
For Table 2.3.3.1 – "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 ii) 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 ii) 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 completed in 2014-15
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	Expenditure figures do not include any expenditure for land or easements.

Requirements (instructions and definitions)	Consistency with requirements
by Energex must be inputted in Table 2.3.6.	

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	EPM

7.3 Methodology

All figures for RIN table 2.3.3 are calculated by firstly defining the Energex projects that related to distribution Augex. Each of these projects is then classified as HV, LV or Distribution Substation and the quantity and expenditure against each project reported in the respective categories. Lastly the distribution components of any projects identified in RIN tables 2.3.1 and 2.3.2 as subtransmission projects is added to the figures.

7.3.1 Assumptions

Energex applied the following criteria to obtain the required information:

- Overhead open wire conductor can be used at any voltage. Overhead conductor with an unspecified voltage is deemed HV;
- Projects unassigned to an asset class are assigned to HV feeders.

7.3.2 Approach

1) A report is run from EPM Business Objects which list all projects with transactions within the 2014/15 regulatory year under the Augex financial activity codes in Table 7.3:

Table 7.3: Augex Financial Activity Codes for Project Transactions 2014/15

Activity Code	Description
C2020	EIT Augmentation – Sub Transmission & Transmission
C2030	PRT Reliability & Power Quality
C2050	CWT Demand Prim Reliability Sec

Activity Code	Description
C2060	EIT Augmentation - 11kV Network
C2070	EIT Land & Right of Way
C2075	EIT Easements
C2095	EIT Infrastructure Projects
C2080	CWT Community Requirements
C2590	EID Eng & Admin
C2565	EID Company Initiated
C2580	EID Control & Metering (Incl. DSM)

2) This report included all Energex projects, not only those related to HV feeders, LV feeder and distribution transformers. As such, the project list is filtered to include only those relating to relevant.

3) The extracted project list reports each project and their total yearly expenditure broken down by direct costs and overheads as per the Energex CAM.

Project Data Allocation

1) Expenses and quantities are characterised by AER Augex asset categories consistent with Energex's regulatory submission.

2) The mapping of assets to AER Augex asset categories is based on analysis of stock items mapped to corresponding Repex asset categories classifications.

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

4) 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 $0 for distribution transformer projects.

5) 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 $0 for distribution transformer projects.

6) Distribution expenses for projects with accumulated expenditure less than the defined thresholds are considered "non-material".

7) Any other non-material expenses are apportioned based on percentage distributions of stock code classifications (outlined above).

8) Projects are assessed to determine whether the augmentation is an upgrade of an existing asset or an addition to the network. This is based on keywords (refer to Table 7.4) within the project title description coupled with reviews of project documentation.

Table 7.4: Key Words used to Categorise Upgraded or Added

HV Feeders		LV Feeders		Distribution Transformers	
Upgrade	Addition	Upgrade	Addition	Upgrade	Addition
Voltage	Est	Rep	Rec	Rep	Rec
Fault Level	Establish	RP	Rel	RP	Rel
Fault Lvl	New	Recon	Ins	Recon	Ins
	Tie	Rtf	Ext	Rtf	Ext
		Up	Instx	Up	Instx
		Fault	Inssp	Fault	Inssp
		VI	In	U/Hgt	In
		U/Hgt	Er	Mod	Er
		Mod	Install	UH	Install
		UH		U/H	VI
		U/H		Impr	
		Impr		Underheight	
		Underheight		Retension	
		Retension		Maint	
		Maint			

Annual expenditure is reported as the summation of projects within each of the categories.

These steps are undertaken for all projects that are distribution driven projects.

9) For reliability and power quality type projects (Activity Code: 2030), the approved scope of works is reviewed to determine whether the augmentation is an upgrade of an existing asset or an addition to the network. Where projects included a combination of additions and upgrades, the project is categorised based on the longest length component between the two categories.

Subtransmission primary projects

- The AER requires distribution components of subtransmission projects to also be reported in RIN table 2.3.3. This clarification by the AER required the distribution costs of a project to be separated from the main project (such as a new zone substation). The projects are allocated to the asset class using the same method detailed above with the additional step of extracting the distribution component for the project.

- The classification of distribution materials in subtransmission projects, as Addition or Upgraded, has been done by analysis of the feasibility study report or the engineering specification - whichever represents the most recent information for that project. The units added or upgraded associated with the distribution components of a subtransmission project are apportioned based on the spread of distribution materials outlined by the feasibility study report or the engineering specification.

7.4 Estimated Information

Data apportioned is based on the cost of purchased materials excluding non-materials.

7.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN tables 2.3.3. As such Energex had to manually categorise each element into its respective categories as per the RIN table 2.3.3.

7.4.2 Basis for Estimated Information

Not applicable.

7.5 Explanatory notes

Differences between last CARIN (2013/14 data from Submission) VS 2014/15 CARIN methodology

- More stock codes mapped
- Change of AER Category of previous year stock codes (e.g. LV service cable was previously mapped to Overhead Conductor)

Old Methodology

Asset Group	Count of Stock Code
Overhead Conductor	37
Pole Top Structures	31
Poles	35
Public Lighting	135
Switchgear	140
Underground Cable	60
Transformers	97
Scada/Protection	92
Grand Total	**627**

Other	Count of Stock Code
Materials - Other	4506
Grand Total	**4506**

New Methodology

Asset Group	Count of Stock Code
Poles	51
Switchgear	681
Pole Top Structures	92
Public Lighting	181
Underground Cable	66
Overhead Conductor	30
Transformers	429
Services	4
Scada/Protection	217
Grand Total	**1751**

Other	Count of Stock Code
Materials - Other	10163
Grand Total	**10163**

- Allocation of 2014/15 expenditure was apportioned based upon the total life to date materials for a Project not just the materials purchased in 2014/15. This may result in no physicals recognised in 2014/15 but an apportionment of expenditure (e.g. “Pole Top>66kV<=132kV”). Also, if no life to date material purchases an apportionment was based upon the estimated stock items in the in-progress estimate with a construction or construction warehouse flag. Furthermore, if no stock items identified with issued or estimate stock items a manual allocation was performed to map to an AER category. Any stock items which mapped to the AER category “Other Other Materials” were ignored in the allocation of expenditure.

8. BoP 2.3.4 - Augex Summary Table

The AER requires Energex to provide the following information relating to RIN table 2.3.4:

- **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**

All information is Estimated Information.

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 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 and easements' rows are mutually exclusive.

Requirements (instructions and definitions)	Consistency with requirements
land purchases and easements'.	

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	EPM[2]

8.3 Methodology

All figures for RIN table 2.3.4 are calculated based on the data generated to populate RIN tables 2.3.1 to 2.3.5. The population of RIN table 2.3.4 is completed by filtering the list of projects with expenditure recorded in the period into the required project classifications.

8.3.1 Assumptions

Energex applied the following criteria to obtain the required information:

- Overhead open wire conductor can be used at any voltage. Overhead conductor with an unspecified voltage is deemed to be HV.
- If projects are unable to be assigned to an asset class they are assigned to HV feeders.
- Sub-transmission projects for RIN table 2.3.1 or 2.3.2 are either substation or lines projects based on the project description.
- Where projects have a significant combination of sub-transmission and distribution works, as incurred expenditure is apportioned based on the relative material costs of sub-transmission assets and distribution assets issued during the period.
- Strategic land and easement purchases are included as Other Assets in RIN table 2.3.4.

[2] EPM is an Enterprise Data Warehouse (EDW). It takes data from across the organisation overnight, every night, filters it against the agreed business principles and then stores it. Business users can then access the information through the 'visualisation suite of tools' and be confident that the information they obtain is from a single source of the truth for performance information.

8.3.2 Approach

Project List Development

- A report is run from EPM Business Objects which listed all projects with transactions within the 2014/15 regulatory year under the following Augex financial activity codes:

Activity Code	Description
C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Reliability Sec
C2060	CWT Demand Prim Refurbishment Sec
C2070	CWT Land & Right of Way
C2075	CWT Easements
C2080	CWT Community Requirements
C2090	CWT Eng & Admin
C2095	CWT Infrastructure Projects
C2565	CWDA Co Initiated
C2580	CWDA Control & Metering

- This report includes all Energex projects.
- The extracted project list reported each project and their total yearly expenditure broken down by direct costs and overheads as per the Energex CAM.

Project Data Allocation

- The methodology for sub-transmission project data allocation is detailed in Basis of Preparation 2.3.1 Augex - Sub-transmission.
- The methodology for Distribution project data allocation is detailed in Basis of Preparation 2.3.3 Augex - Distribution.

Data Extraction

The following rules are applied to the dataset to extract expenditure associated with each of the project types:

Sub-transmission substations, switching stations, zone substations

- Sum of proportioned Sub-transmission expenditure where Subtransmission Project type = TCAP – Sub.

Sub-transmission lines

- Sum of Proportioned Sub-transmission expenditure where Project type = TCAP – Line.

HV feeders

- Sum of proportioned distribution expenditure where Project type = HV Feeder.
- Less land purchased and easements in the year.

HV feeders – land Purchase and easements

- Sum of proportioned distribution land and easement expenditure where Project type = HV Feeder.

Distribution substations

- Sum of proportioned distribution expenditure where Project type = Dist Tx.
- Less land purchased and easements in the year.

Distribution substation – land purchase and easements

- Sum of proportioned distribution land and easement expenditure where Project type = Dist Tx .

LV Feeders

- Sum of proportioned distribution expenditure where Project type = LV Feeder.
- Less land purchased and easements in the year.

LV Feeders – land purchase and easements

- Sum of proportioned distribution land and easement expenditure where Project type = LV Feeder.

Other Assets

- Sum of Proportioned Sub-transmission expenditure where Project type = Land easements.

8.4 Estimated Information

All information is Estimated Information.

8.4.1 Justification for Estimated Information

- Energex does not capture costs or quantities in the categories required in RIN tables 2.3.4. Data is apportioned based on the value of items purchased, then manually categorised to each AER category.
- The timing of land and easement expenditure is not captured in the data extract. For consistency, land and easement expenditure is recorded in the final year of expenditure, similar to asset volumes in RIN table 2.3.3.1. Land and easement expenditure is less than 1 percent of distribution Augex expenditure.

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 $ 2014/15.
  - RIN table 2.3.1 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

Estimated 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	POW010EPM Report (POW010), Ellipse, EPM materials report
Augmentation Metrics	POW010EPM Report (POW010), Ellipse, EPM materials report
Commercial/Industrial	
Distribution Substation Metrics	POW010EPM Report (POW010), Ellipse
Augmentation Metrics	POW010EPM Report (POW010), Ellipse, EPM materials report
Subdivision	
Underground and Overhead Connections	Report Explorer ELL00197 -number of lots commissioned
Distribution Substation Metrics	POW010EPM Report (POW010), Ellipse, EPM materials report
Augmentation Metrics	POW010EPM Report (POW010), Ellipse, EPM materials report
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	EPM Report (POW010), Ellipse, EPM materials report
Table 2.5.2 – Cost Metrics	
Residential	
Simple Connection LV	EPM Report (POW010), EPM materials report

Variable	Source
Complex Connection LV	EPM Report (POW010), EPM materials report
Complex Connection HV	EPM Report (POW010), EPM materials report
Commercial/Industrial	
Simple Connection LV	EPM Report (POW010), EPM materials report
Complex Connection HV (Customer Connected At LV, Minor HV Works)	EPM Report (POW010), EPM materials report
Complex Connection HV (Customer Connected At LV, Upstream Asset Works)	EPM Report (POW010), EPM materials report
Complex Connection HV (Customer Connected At HV)	EPM Report (POW010), EPM materials report
Complex Connection Sub-Transmission	EPM Report (POW010), EPM materials report
Subdivision	
Complex Connection LV	EPM Report (POW010), EPM materials report
Complex Connection HV (No Upstream Asset Works)	EPM Report (POW010), EPM materials report
Complex Connection HV (With Upstream Asset Works)	EPM Report (POW010), EPM materials report
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 2014/15 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” that is greater than 90% of the total direct cost of the project was excluded based on the AER’s instructions to exclude gifted assets. Projects with less than 90% gifted were considered to have additional work completed after the asset was gifted and therefore should be included in this Regulatory Template.

- 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, ie. C2095 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” that is greater than 90% of the total direct cost of the project was excluded based on the AER’s instructions to exclude gifted assets. Projects with less than 90% gifted were considered to have additional work completed after the asset was gifted and therefore should be included in this Regulatory Template.

- 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” that is greater than 90% of the total direct cost of the project was excluded based on the AER’s instructions to exclude gifted assets. Projects with less than 90% gifted were considered to have additional work completed after the asset was gifted and therefore should be included in this Regulatory Template.

- 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 2014/15 regulatory year were extracted using the POW010 report. This report detailed all projects along with the following items:
  - Project description
  - Financial activity code
  - Expenditure
- An extract from EPM of the materials used on each project was joined to the list of projects cost by year. These material transactions were 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
Street lighting (defined by activity codes C2560 and C3560 non gifted)	Street lighting projects were not to be included within the connections Regulatory Template.
Projects with gifted assets (defined by projects with any transaction in element 6270)	Where a project costs is 90% or more attributed to the gifted asset element, these projects were excluded.
Incorrectly set up projects (defined by projects under the activity codes C2545 and C2565)	Some projects were incorrectly setup and should not have been included in the project list for connections.
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.

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 between 2006/07 and 2014/15. Note that the stock codes were analysed in the years prior to and years after the reportable period to ensure that a project was not inadvertently misclassified.
  - 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. Cable figures were analysed from 2006/07 to 2014/15 to ensure a project was not inadvertently misclassified. If a project had a higher dollar figure of HV cable across these years 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. If there was no material to indicate voltage, then the project description was used to determine voltage.

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 2014/15 regulatory year.
- 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’ and 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 the 2014/15 regulatory year.
- 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’ and 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 for the 2014/15 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 2014/15 regulatory year for projects under C2510 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 2014/15 regulatory year.
- 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 2014/15 regulatory year.
- 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 2014/15 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 2014/15 regulatory year for projects under C2550 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 2014/15 regulatory year.
- 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 2014/15 regulatory year.
- 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 2014/15 regulatory year.

- 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 2014/15 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 expense value.

- The expense values were calculated as the total project expenses in the 2014/15 regulatory year. The volumes of connections were calculated by using the frequency of projects in the 2014/15 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, high voltage cable (>1kV) or both. 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 2014/15 regulatory year. The volumes of connections were calculated by using the frequency of projects in the 2014/15 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 2014/15 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 2014/15 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 2014/15 regulatory year. The volumes of connections were calculated by using the frequency of projects for the 2014/15 regulatory year.

- Complex Connection HV (Customer Connected At HV)
  - This classification was determined to be projects under the C20 funding type that were identified as HV projects. The projects were identified as being HV by analysis of the stock codes under each project.
  - The expense values were calculated as the total project expenses in the 2014/15 regulatory year. The volumes of connections were calculated by using the frequency of projects in the 2014/15 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.
  - The expense values were calculated as the total project expenses in the 2014/15 regulatory year. The volumes of connections were calculated by using the frequency of projects for the 2014/15 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

- The simple LV connection expenditure from activity C2570 which is apportioned over Residential and Commercial/Industrial is considered to be an estimate.
- All data is estimated as the apportionment to each category is based on materials booked to the project, project description or financial activity code.

9.4.1 Justification for Estimated Information

- Data is not captured in the categories required in RIN tables 2.5.1 and 2.5.2; therefore costs were required to be apportioned.

9.4.2 Basis for Estimated Information

- Each cost and quantity was manually categorised using multiple descriptors within the data. For full details please refer to the approach section above.

9.5 Explanatory notes

- The connection counts were based upon the count of projects that were determined to fall in the particular categories required in Regulatory Template 2.5. Where a project was done over multiple years it may have been previously reported (i.e. counted more than once), however the effect of this is immaterial.

- All MVA added and circuit kilometres added metrics were based on the stock codes charged to the project in each particular year and will therefore not be double counted.

- LV connection expenditure is largely based on activity C2570. This activity includes approximately $93 million in metering expenditure. This is detailed in Regulatory Template 4.2. Expenditure associated with metering was removed from activity C2570 prior to allocation in Regulatory Template 2.5.

- A general reduction in MVA installed and associated cost is due to the reduction in load forecasts, and therefore reduced requirements for customer driven demand spend. The variability of the commercial MVA installed is driven by the types of projects commissioned for a particular financial year. This can include allowance for future growth.

- Historical data reported in Energex's Reset RIN differs from information submitted for the Category Analysis (CA) RIN due to a differing definition of connection expenditure in the Reset RIN which made the exclusion of relocation of assets explicit. Per the Category Analysis (CA) RIN definition, relocation of assets expenditure has not been excluded from data presented.

- It should be noted that, whilst extracting and analysing data and applying an exclusion for metering costs for the Reset RIN for the 2013/14 year an error was identified in relation to information previously reported for the CA RIN. This error relates to the incorrect exclusion of some costs reported for connections in the CA RIN. This error has been corrected and information reported in the 2014/15 CA RIN reflects the corrections made.

- The following Projects were identified as containing metering upgrade costs in activity C2570 Service Line Connections:
  - C0136192 New Connections / Meter Upgrades
  - C0333740 C25_16/14_SC14_MN_ANNUAL

  At total of $480,266.16 was adjusted from Connections and reported in Metering.

- All costs in with asset category = "Metering" except for $324,012.28 in "OH allocation pool capex accrual" were moved to Metering. The total amount moved was $12,979,323.48 as detailed in Table 9.4:

Table 9.4: Costs in Asset category "Metering"

Asset_Category	Top Project No	Top Project Description	SumOfDirect
Metering	C0378333	CUST SERV R/P MTR COMP SC14 14/15	88,305.16
Metering	C0416289	New Connections Install Meter	5,190,217.66
Metering	C0416290	A&A Install Meter	7,261,412.90
Metering	C0416292	A&A Install Control Load	438,887.61
Metering	C0460148	Customer Initiated Meter Install Type 6	500.15
			12,979,323.48

- Planned service line replacement programs have been included and categorised as Repex activities in 2014/15. The expenditure for this program was captured under C2570 for 2014/15 and would have normally been mapped to the Connections template 2.5. Service line replacement quantities include number of services replaced under the planned program (NAMP line CA12), as well as apportioned material booked out under normal Repex activities.

  The Planned service line replacement expenditure and quantities (NAMP line CA12) which has been remapped to the Repex template is as follows:

  – 14/15 Units: 21,610

  – 14/15 Expenditure: $16,783,511

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	Demonstrated in section 1.2 (Methodology)
GSL payments made to residential customers	Demonstrated in section 1.2 (Methodology)
Volume of complaints relating to connection services	Demonstrated in section 1.2 (Methodology)
Connection means a physical link between a distribution system and a retail customers premises to allow the flow of electricity.	Demonstrated in section 10.3 (Methodology)
Simple connection low voltage is defined as a single/multiphase customer service connection.	Demonstrated in section 1.2 (Methodology)
Complaint is defined as a written or verbal expression of	Demonstrated in section 1.2

Requirements (instructions and definitions)	Consistency with requirements
dissatisfaction about an action, or failure to act, or in respect of a product or service offered or provided by an electricity network distributor.	(Methodology)

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	PEACE (FRC213)
Complaints	Cherwell
GSL Breaches & GSL Payments	Cherwell

10.3 Methodology

- Data provided in RIN tables 2.5.2 and 2.5.1 is derived from the business objects report FRC213 which extracts data from PEACE CIS system. FRC213 is automatically run each day to extract details of any service order that reached a status of “service order response sent” (for Retailer initiated work) on the previous business day. The FRC213 report also identifies the market outcome status for each service order. This market outcome status identifies whether the service order was completed, attempted but unable to be completed, or cancelled.
- Due to the above parameters, the FRC213 report details service order jobs based on the date the service order response was sent to the requesting retailer and not the date the job was completed in the field. As such, at times there may be a variance between the date the job is completed in the field and the date the job appears in FRC213.
- 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.
- Connections have been collated based on customer initiated work requests within the reportable period.
- For the volume of connections, it is assumed that each top project represents one connection which was determined as per basis of preparation in RIN table 2.5.1. All remaining connections not associated with a project were determined to be simple.
- 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 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. The earliest work start date is defined as the latest date of either;
  - B2B Received Date + 1
  - B2B Obligation Start Date
  - Form 2 Received Date + 1
  - Form 2 Ready for Test Date.
  - Appointment Date
- 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) Collation of monthly reports for financial year

2) Total volumes of connections to the network are established by summing the total volume of connection service orders (from the FRC213 reports) where the market outcome status was “complete” for the financial year.

3) 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.

4) When using the above approach, the percentage of each unknown connection type (Residential, Commercial & Industrial and Embedded Generation) was less than 10 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) Collation of monthly reports for financial year

2) Exclusion of complaints not categorised as the following:
    a. New connection
    b. Existing connection

3) 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 monthly reports for financial year

2) Exclusions of GSLs not categorised as the following
    a. New Connection

3) Total volumes of GSL breaches are established by summing the total volume of the New Connection GSLs paid for each financial year.

4) 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

- Embedded Generation volumes continue to decline in 2014/15 year when compared to prior years reported. This is a reflection of changes in Government rebate schemes and the subsequent decline in consumer appetite.

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 2014/15:

- **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 all figures inclusive of Direct costs and on-costs but excluding overheads as per the Energex CAM approved by the AER.
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 2015
- User numbers – Microsoft Active Directory reports.
- 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.
- SCCM is a Microsoft product used for systems management which has the ability to auto discover devices on the network and determine what software etc. is running on them.

- 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: Information sources

Variable	Source
Client Device Expenditure – OPEX ($0's)	SPARQ Solutions information based on invoices issued to Energex
Client Device Expenditure – CAPEX ($0's)	Accounting Entry Report per Ellipse
Recurrent Expenditure – OPEX ($0's)	Profit and Loss for SPARQ Solutions division from EPM for Cost of Sales, Telecommunications, Asset Usage Fee, Finance Fee & SLA
Recurrent Expenditure – CAPEX ($0's)	Capex expenditure per Regulatory accounts less Client Devices per Accounting Entry Report
Non-Recurrent Expenditure – OPEX ($0's)	Profit and Loss MOPEX RC 1020, account 4940 for 14/15
Non-Recurrent Expenditure – CAPEX ($0's)	Not applicable

Variable	Source
Employee numbers	Sourced from Energex Monthly Performance Report for June 2015
User numbers	Active IT system log in account used in the year
Number of devices	Client devices used as provided IT services

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:

OPEX

1) SPARQ Solutions provided financial data detailing the charges from SPARQ Solutions to Energex. EPM reports identified the SPARQ responsibility centre to obtain 2014/15 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, Finance Fee 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.

CAPEX

1) Client devices Capex – Client devices capex was identified from the Accounting Entry Report for 2014/15, 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 2015.

2) User Numbers – The number of users was extracted at a point in time and represents as the number of active IT system log-in accounts used during each year. 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 eg. 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.

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

IT & Communication (Client Device Expenditure) has increased 68% ($949k to $1,593k) due to the help desk clearing backlog of non-critical calls and upgrading of computers from 32 byte to 64 byte to be compatible with more complex software being used.

11.6 Accounting policies

The Accounting Policies adopted by Energex during the 2014/15 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, Motor Vehicles Generators – 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: Tools & Equipment – Other Motor Vehicles: Mobile Generators

Requirements (instructions and definitions)	Consistency with requirements
	– Other Non-Network Expenditure Fleet
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	This definition has been applied.

Requirements (instructions and definitions)	Consistency with requirements
vehicles (e.g. forklifts, boats etc.); • mobile plant and equipment; tools; trailers (road registered or not); and • elevating work platforms not permanently mounted on motor vehicles; and mobile generators.	

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 2014/15	• 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 2014/15	• 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 2014/15	• 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 2014/15:

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 Commercial services (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 80/20 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 2014/15:

1) Obtained the Capital Summary report and Detailed Capital Transaction Report for Motor Vehicles, Tools and Equipment from Commercial Services (Energex finance team). These reports were used to identify the total of the financial purchases in the 2014/15 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 Crane Borers and Elevated Work Platforms.

3) Per Clause 10.5 of the CA RIN, Energex has incurred $1 million or more in capital expenditure for two classes of assets and these are therefore reported separately. These additional asset classes are Motor Vehicles Generators and Tools & Equipment. 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 2015. 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 2014/15:

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 2014-15 FY. This was sourced from the Energex Fleet Program of Work file. This file is managed by the Asset Management and Technical Support team.

2) Vehicles that were paid and delivered to Energex in 2014-15 FY but not commissioned as at 30 June 2015 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.

- A payment of $1.1M was made to the Office of State Revenue (OSR) for stamp duty relating to heavy commercial and heavy commercial – elevated work platform vehicles. This stamp duty related to vehicle purchases over a number of years in the 2010-15 regulatory period. The stamp duty was allocated based on expenditure in the above vehicle categories.

- For 2014-15 an amount of $0.9M in fuel tax credits was received.

- The ATO deemed that Energex is liable for an additional Fringe Benefits Tax related to staff parking at the Newstead corporate office from 2014/15 onwards based on the emergence of commercial parking being available in the near vicinity.

12.6 Accounting policies

The Accounting Policies adopted by Energex during the 2014-15 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 2014/15:

- **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
Other – Other – CAPEX ($0's) Other – Office Furniture – CAPEX ($0's) Other – Plant & Equipment – CAPEX ($0's)	Accounting Entry Report (FIN077) for RC 2510 and all CAPEX activities

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 and Non Network Other – Office Equipment CAPEX for 2014/15:

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) The remaining dollar value was used to report the 14/15 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 – Office Furniture – CAPEX.

3) Capex values for a sweeper/scrubber have been reported as “Other – Plant and Equipment”.

13.4 Estimated Information

No Estimated Information has been reported.

13.5 Explanatory notes

Building and Property Capex increased quite significantly in the 14/15 FY compared to the 13/14 FY as the 13/14 FY was a building project planning and approval year whereas 14/15 saw the actual commencement of construction on these building projects.

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 b) 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 b) 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	Please refer to section 14.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
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 c) 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… b) 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

Variable	Source
Number Of Maintenance Spans (0's)	Field Survey ArcGIS
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

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 (note for the 14/15 FY we were not able to bed down the AER definition of a corridor until January so the figures provided are for the last 6 months and are then doubled to give a full years view. For future financial years a full 12 months will be used). To determine the break up for urban and rural the total % of urban/rural network for Energex was 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.

14.4.1 Justification for Estimated Information

Energex was unable to confirm and apply the AER's definition of a corridor until January 2015. As such, figures for the 2014/15 regulatory year represent six months' worth of Actual Information (January 2015 to June 2015) doubled to provide an estimate of the full year results. For future financial years a full 12 months will be used and information will be reported as Actual Information.

14.4.2 Basis for Estimated Information

Not applicable.

14.5 Explanatory notes

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 b) 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 b) the total network area with the borders of each vegetation	The map of all Energex vegetation management zones is contained in Appendix 4 –

Requirements (instructions and definitions)	Consistency with requirements
management zone.	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, 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 c) 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	Refer to section 15.5 (Explanatory Notes)

Requirements (instructions and definitions)	Consistency with requirements
Regulatory Template 2.7 (or added in Regulatory Template 2.8) in 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 2014/15 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.

15.4.1 Justification for Estimated Information

Energex was unable to confirm and apply the AER's definition for corridor, ground cutting, audit and inspection variables until January 2015. As such, figures for the 2014/15 regulatory year represent six months' worth of Actual Information (January 2015 to June 2015) doubled to provide an estimate of the full year results. For future financial years a full 12 months will be used and information will be reported as Actual Information.

15.4.2 Basis for Estimated Information

Not applicable.

15.5 Explanatory notes

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 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**

The following information is Estimated Information:

- **Asset quantity - at year end**
  - **Service Lines – Number of Customers**
- **Asset quantity inspected/maintained**
  - **All variables**
- **Average age of asset group**
  - **All Overhead Assets – line patrolled(route KM)**
  - **LV-11 to 22KV - Length(KM)**
  - **33KV and Above – Length(KM)**
  - **CBD – Length(KM)**
  - **NON CBD – Length(KM)**
  - **All zone substations properties – Number of Zone substation properties maintained**
  - **All Underground Feeder Assets**
- **Inspection and maintenance cycles**
  - **All data**

All remaining 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. 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.	Data has been provided in accordance with this requirement. Please refer to section 17.3.2 (Approach).
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.
For 'Other maintenance activity', add rows for maintenance expenditure subcategories if these are material and if these	Extra lines were added where

Requirements (instructions and definitions)	Consistency with requirements
are not yet included in any other maintenance expenditure subcategory.	applicable.

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	• NFM
Asset quantity inspected/maintained	• EPM POW015/POW016
Average age of asset group	• NFM
Inspection Cycle	• Substation Asset Maintenance Policy (SAMP) • Mains Asset Maintenance Policy (MAMP) • Joint Workings Network Maintenance Framework
Maintenance Cycle	• Substation Asset Maintenance Policy (SAMP) • Mains Asset Maintenance Policy (MAMP) • Joint Workings Network Maintenance Framework
Service Cable	• 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 including 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 2014/15 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, a matrix has been developed to map Energex's NAMP codes to equivalent AER RIN categories.

- 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.

- Street lighting – Street lighting maintenance was apportioned between major roads and residential roads. Apportionment was based upon asset quantities in each category as at year end. There is no reported expenditure for maintenance on Streetlights as these costs are not attributed to the 41100 or 41200 financial activities used to map expenditure to Table 2.8.2. Streetlight maintenance costs relate to the 41600 financial activity (ACS), and is represented in template 4.1 Public Lighting.

Underground cable maintenance:

- Underground cable maintenance was apportioned between CBD and non-CBD based on the 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	214,342 meters	1.23%
Non-CBD	17,176,006 meters	98.76%

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 NFM 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 (volumes per Table 17.4 below) have been excluded.

Table 17.4 – Poles excluded from Asset Quantity

Plastic Poles	Quantity
< = 1 kV	13
> 1 kV & < = 11 kV	11
> 22 kV & < = 66 kV	0
> 66 kV & < = 132 kV	0

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) The pole quantity was calculated as the sum of poles installed up to and including the end of the 2014/15 year.

Service Lines – Number of Customers:

1) The number of service lines for 2014/15 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 NFM 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 17.5 – Customer owned Conductor Length

Customer Conductor	2014/15
Length (km 000's)	8.31

4) Lengths have been reported in Kilometres (km)

Underground Cable Length (Route km):

1) A report was run from NFM 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

   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 17.6 – Customer owned cable

Customer Cable	2014/15
Length (km 000's)	21.70

4) Lengths have been reported in Kilometres (km)

Distribution Substation – Number of Installed Transformers:

1) A report was extracted from NFM detailing the transformers in the Energex network with the following corresponding information:

   a. Location – Zone or Distribution

   b. Transformer Type – Power or 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.

2) The report was filtered to show the following category:
   a. Location equals Distribution (DIST)

Distribution Substation – Number of Switches:

1) A report was extracted from NFM that contained an extract for the 2014/15 financial year detailing the circuit breakers and re-closers in the Energex network with the following corresponding information:
   a. Snapshot date
   b. Equipment type
   c. Install date

   This report includes all circuit breakers and re-closers that were commissioned at the relevant point in time.

   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 NFM for the 2014/15 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 NFM for the 2014/15 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 NFM for the 2014/15 financial year detailing the transformers in the Energex network with the following corresponding information:
    a. Location – Zone or Distribution
    b. Transformer Type – Power or 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.

2) Report had filters applied to the following categories:
    a. Transformer Type equals Power (TR-PW)
    b. Location equals Zone

Zone Substation – Number of Distribution Transformers within Zone Substations:

1) A report was extracted from NFM for the 2014/15 financial year detailing the transformers in the Energex network with the following corresponding information:
    a. Location – Zone or Distribution
    b. Transformer Type – Power or 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.

2) Report had filters applied to the following categories:
    a. Transformer Type does not equal Power (TR-PW)
    b. Location equals Zone
    c. Has Customer equal Yes

Zone Substation – Number of HV Transformers:

1) A report was extracted from NFM for the 2014/15 financial year detailing the transformers in the Energex network with the following corresponding information:
    a. Location – Zone or Distribution
    b. Transformer Type – Power or 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.

2) Report had filters applied to the following categories:

a. Transformer Type does not equal Power (TR-PW)

b. Location equals Zone

c. Has Customer equal No

Zone Substation – Other Equipment:

1) A report was extracted from NFM for the 2014/15 financial year detailing Connectivity Assets and Non Connectivity Assets:

a. Snapshot Date

b. Installation Date

c. Quantity

2) The Connectivity Assets report excluded all assets that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

3) Connectivity Asset report also excluded the following assets:

a. Transformers

b. Tee Off

c. Cable Boxes

d. Circuit Transformers

e. Cable Joints

f. Fault Indicators

g. Switch Fuses

4) The Non Connectivity Assets report included the following assets

a. Ring main units

b. Battery Banks

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.

5) 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 NFM for the 2014/15 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 NFM for the 2014/15 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 2014/15 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) Data reported was the same as stated for "Zone Substation – Number of Zone Substation Properties Maintained" above. For the details of the methodology refer to the relevant section above.

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) POW015/POW016 EPM reports were used to identify the work orders that related to each of the NAMP lines.

2) Data was extracted for activities codes 41100 and 41200 which represent maintenance activities. Data was also extracted from 41500 for NAMP line TF16 (Access Tracks).

3) Maintenance and inspection data was allocated to the appropriate RIN categories by matching the unit counts for a relevant work order back to its assigned NAMP code, and therefore in turn to the primary maintenance activity in the RIN (based on the mapping of NAMP codes to RIN Asset Categories).

4) Projects/work orders that had not been identified in the POW015/POW016 reports as being associated with specific NAMP codes were reviewed and assigned to NAMP codes where possible based upon the project / work order description.

5) A zero balance is shown for “Transformers – Distribution” and “Transformers – HV”. This is because asset inspection and maintenance for these assets are conducted as part of the whole zone substation inspection, which covers all assets at a site.

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 2014/15 is the average of assets from 1910/11 to 2014/15.

Service Lines – Number of Customers:

1) The number of service lines and their age profile for 2014/15 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) 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 2014/15 is the average of assets from 1910/11 to 2014/15.

Underground Cable Length (Route km):

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 2014/15 is the average of assets from 1910/11 to 2014/15.

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 2014/15 is the average of assets from 1910/11 to 2014/15.

Distribution Substation – Number of Switches:

1) A report was extracted from NFM that contained an extract for the end the 2014/15 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 and reclosers that were commissioned, at the relevant point in time. This report excludes all assets indicated as customer owned.

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 NFM that contained data for the end the 2014/15 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 NFM that contained data for the end the 2014/15 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 NFM that contained data for the end the 2014/15 financial year detailing the transformers in the Energex network with the following corresponding information:

    a. Location – Zone or Distribution

    b. Transformer Type – Power or 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 asset indicated as customer owned.

2) Report had filters applied to the following categories:
   a. Location equals Zone
   b. Transformer Type equals Power (TR-PW)

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

4) Average age was calculated from the installation date.

Zone Substation – Number of Distribution Transformers Within Zone Substations:

1) A report was extracted from NFM that contained data for the end the 2014/15 financial year detailing the transformers in the Energex network with the following corresponding information:
   a. Location – Zone or Distribution
   b. Transformer Type – Power or 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 asset indicated as customer owned.

2) Report had filters applied to the following categories:
   a. Location equals Zone
   b. Transformer Type does not equal Power (TR-PW)
   c. Has Customer equal Yes

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

4) Average age was calculated from the installation date.

Zone Substation – Number of HV Transformers:

1) A report was extracted from NFM that contained data for the end the 2014/15 financial year detailing the transformers in the Energex network with the following corresponding information:
   a. Location – Zone or Distribution
   b. Transformer Type – Power or 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 asset indicated as customer owned.

2) Report had filters applied to the following categories:

    a. Location equals Zone

    b. Transformer Type does not equal Power (TR-PW)

    c. Has Customer equal No

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

4) Average age was calculated from the installation date.

Zone Substation – Other Equipment:

1) A report was extracted from NFM that contained data for the end the 2014/15 financial year detailing Connectivity Assets and Non Connectivity Assets:

    a. Snapshot Date

    b. Installation Date

    c. Quantity

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

    Connectivity 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

    The Non Connectivity Assets report included the following assets:

    a. Ring main units

    b. Battery Banks

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.

2) The Connectivity Assets and Non Connectivity Assets reports were combined

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

4) Average age was calculated from the installation date.

Zone Substation – Number of Zone Substation Properties Maintained:

1) A report was extracted from NFM that contained data for the 2014/15 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 2014/15 is the average of assets from 1910/11 to 2014/15.

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 that contained data for the 2014/15 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) Data reported is the same as stated for “Zone Substation – Number of Zone Substation Properties Maintained” above. For the details of the methodology refer to the relevant section above.

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 2014/15 is the average of assets from 1910/11 to 2014/15.

17.3.2.4 Inspection and Maintenance Cycles

1) The cyclic frequencies that Energex have reported are based on current policy requirements obtained from the Substation Asset Maintenance Policy (SAMP), Mains Asset Maintenance Policy (MAMP) and Joint Workings Maintenance Activity Frequency (MAF) document. A combination of all three policy documents was used depending on the activity.

2) Where multiple NAMP lines were mapped to a single Asset Category, the highest expenditure NAMP line was used for each inspection and maintenance activity (mapped back to financial activities). That is to say, if an AER category contained NAMP lines of both inspection and maintenance financial activities (41100 and 41200 respectively), then the highest expenditure for the NAMP for each activity was used. NAMP’s without routine cycles (reactive in nature) were excluded from this logic. This was because typically highest expenditure was always reactive NAMP lines.

3) Under each NAMP line there are standard jobs which typically breakdown the NAMP to a more detailed level – often to manufacturer make/model. Each piece of equipment used for maintenance is dependent on a range of variables, such as manufacturer, model and insulating properties. As such, each piece of equipment

embodies a different frequency associated with routine maintenance. To account for this, Energex has used the frequency of the highest quantity of inspection or maintenance activity for the standard jobs under the NAMP for the financial year.

Alternative method would be to use the highest count/population of each standard job. Energex has chosen the highest count per financial year so as to better reflect expenditure per financial year. This does mean however, that each financial year, the inspection and maintenance cycles will change dependant on what has triggered or fallen within the reported financial year.

4) If the Asset Category was mapped to a single NAMP line which did not have a routine maintenance or inspection cycle (that is, the NAMP line was for a program completely reactive in nature), the field was left blank.

5) Asset Categories which were mapped to NAMP lines which did not have a routine maintenance cycle (that is, the NAMP lines were for programs that were demand/reactive in nature) but did have an inspection cycle, the maintenance cycle field was left blank.

6) Asset Categories which were mapped to NAMP lines which did not have a routine inspection cycle (that is, the NAMP lines were for programs that were demand/reactive program in nature) but did have a maintenance cycle, the inspection cycle was left blank.

7) Service lines are currently inspected against financial activity 41700 – Customer Services. It is this reason why inspection cycle is left blank (refer point 2) as only 41100 and 41200 financial activities were used in the derivation of cycle times.

17.4 Estimated Information

The following data is estimated:

- Asset quantity - at year end
  - Service Lines – Number of Customers
- Asset quantity inspected/maintained
  - All variables
- Average age of asset group
  - All overhead assets – Line Patrolled(route KM)
  - LV-11 to 22KV - Length(KM)
  - 33KV and Above – Length(KM)
  - CBD – Length(KM)
  - NON CBD – Length(KM)
  - All zone substations properties – Number of Zone substation properties maintained

  - All Underground Feeder Assets
- Inspection and maintenance cycles
  - All data

All remaining information is Actual Information.

17.4.1 Justification for Estimated Information

17.4.1.1 Asset Quantity - At Year End

Service Lines – Number of Customers:

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

17.4.1.2 Asset Quantity Inspected / Maintained – all data:

- Certain categories were determined using NAMP lines. As the NAMP lines used to classify assets inspected/maintained are not a direct match to the categories required in table 2.8.1 the data is considered estimated. The NAMP lines are however considered to be the best representation of the categories available to Energex.
- The remaining categories for quantity of assets inspected/maintained could not be determined from the POW015/POW016 reports as Energex does not capture the required data.
- For details of the methodology by which each variable was calculated please refer to the methodology section above.

17.4.1.3 Average Age of Asset Group

Zone Substation – Number of Zone Substation Properties Maintained:

- Energex does not have accurate dates as to when a substation was first used. This had to be inferred from equipment at the site which may or may not have had replacements prior to NFM implementation. Only asset history on implementation of NFM is currently known.

All Overhead Assets – line patrolled (route KM):

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

LV-11 to 22KV - Length (KM):

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

33KV and Above – Length (KM):

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

CBD – Length (KM):

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

NON CBD – Length (KM):

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

All Underground Feeder Assets:

- These figures were based on the figures calculated for RIN table 5.2.1 (Regulatory Template 5.2 – Asset Age Profile) which were also estimated. As such the data stated is considered estimated.

17.4.1.4 Inspection and Maintenance Cycles – all data

- The calculation of inspection and maintenance cycles required aggregation of the cycles of many different assets into high level categories. Within this aggregation certain assumptions were made that lead the figures to be estimated.

17.4.2 Basis for Estimated Information

- Estimated Information is based on data calculated for Regulatory Template 5.2. For the specific methodology please refer to the Basis of Preparation for that Regulatory Template.

17.4.2.1 Asset Quantity Inspected / Maintained

- Certain values for assets inspected/maintained have been categorised into the categories required in RIN table 2.8.1 by mapping the Energex NAMP lines to the categories required.

- For details of the methodology by which each variable was calculated please refer to the methodology section above.

17.4.2.2 Inspection and Maintenance cycles – all data

- Each piece of equipment used for maintenance is dependent on a range of variables, such as manufacturer, model and insulating properties. As such, each piece of equipment embodies a different frequency associated with routine maintenance. To account for this, Energex has used the frequency of the highest spend for each NAMP line within the Maintenance Asset Category and then the highest volume of standard job within the NAMP line. As a first pass, only NAMP lines which had cyclic/routine cycles were used in the calculation. There were some categories which contain NAMP lines of higher expenditure that aren't cyclic in nature. These were excluded from the calculation.

- If the Asset Category was mapped to a single NAMP line which did not have a routine maintenance or inspection cycle (that is, the NAMP line was for a program completely reactive in nature), the field was left blank.

17.5 Explanatory notes

- In the prior Category Analysis (CA) RIN, submitted in April 2014, 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	Number of Zone substation properties maintained
Distribution Asset Inspection	Distribution Substations	Number of Distribution substation properties maintained
Distribution Pole Mounted Plant Maintenance	All Distribution PMP (Transformers, Regulators, Sectionalisers and Reclosers)	Number of Distribution Transformers, Regulators, Sectionalisers and Reclosers
Underground Feeder Asset Inspection	All underground Feeder Assets	Length (KM)
Pilot Cable Inspection and Maintenance	All Pilot Cables (Copper & Fibre)	Length (Meters)

- Energex has retained these categories for 14/15 CARIN.
- Energex has also included expenditure related to 'Ground Clearance - Access Tracks' separately, as provided in the template.

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**

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 Estimated 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 the regulatory year, for each asset category (b) the number of assets actually inspected or maintained during the regulatory year, for each asset category	RIN table 2.8.1 has been completed in accordance with this requirement

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 and project documentation, CBMD, ROSS, SAM, CNMG
Protection Systems Maintenance	IPS

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 2014/15 financial year using age profile.
  - RTUs;
  - IED;
  - Microwave Links;
  - DSS Head Ends;
  - DSS Radios; and
  - Multiplex equipment (which included MPLS nodes).
- Various techniques were used to create 2014/15 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.
- The average age of assets for these variables were generated using 2014/15 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 2014/15 financial year age profile and determining the average age.

18.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- For Protection Systems Maintenance, records listed in the IPS database as "Discarded" were considered to be actual units that were replaced.
- Assets that were replaced on failure were replaced on a one for one basis and were replaced with new equipment for the asset types associated with this Basis of Preparation.

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 – report from the IPS database 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 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 14/15 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 Estimated Information.

18.4.1 Justification for Estimated Information

For each variable there were two main areas in which the data was required to be estimated:

1) Estimation of age profiles:
   - It was necessary to estimate installation date of replaced equipment in some cases as no data was available. Thus the average age of the asset base is also an estimate.
2) Estimation of multiplex age profile (one asset type covered under “SCADA & Network Control Maintenance”):
   - No historical records were kept of multiplex installation dates. The installation of the multiplex was estimated by determining when fibre pilot cables occurred and spreading the population based on this age profile.

18.4.2 Basis for Estimated Information

Estimation of multiplex age profile: The installation of the multiplex was estimated by determining when fibre pilot cables occurred and spreading the population based on this age profile.

18.5 Explanatory notes

- Trend analysis using historical information previously included in Energex’s CA RIN submission (08/09 – 13/14) will appear inconsistent due to a number of issues progressively identified during preparation of yearly submissions. These include a limitation of the IT solution which artificially reduced the number of reported IEDs and issues with spread sheets used to analyse the data. This impacts the SCADA Network and Control Maintenance Asset Quantities at Year End and the Average Age of Asset Group.

  Energex identified and corrected these issues in this and previous submissions.

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.	No additional rows were 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 work order	EPM FIN077 General Ledger Transactions
NAMP Line / Work Order alignment	EPM POW015/POW016 Physicals reports

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 the previous five years 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, a matrix was developed to map Energex's NAMP codes to equivalent CA RIN categories. Whilst the NAMP codes are not a one-for-one match with the RIN categories they were reasonably aligned.

- Energex has mapped Commercial & Industrial (C&I) substation NAMP lines that do not contain any Zone Substation activities, to Distribution Substations as they are not Zone Substations.

- However, NAMP lines which contain activities for both Zone Substations and Distribution Substations (Commercial and Industrial, Padmounts, Ground mounted sites) have been mapped to Zone Substation activities i.e. NAMP BZ15 – 11kV Circuit Breaker Maintenance contains Bulk Supply, Zone and C&I CB maintenance.

- In instances 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 accordingly to the 'routine' and 'non-routine' expenditure categories respectively in the AER table.

Public Lighting Maintenance

- Public lighting maintenance was apportioned between major and minor roads based on the amount asset quantities at year end for each road type.
- No Public lighting expenditure is reported in this table as it is reported separately in Table 4.1. based on expenditure being ACS under activity 41600.

Underground cable maintenance

- Underground cable maintenance was apportioned between CBD and non-CBD based on the 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	214,342 metres	1.23%
Non-CBD	17,176,006 metres	98.76%

19.3.2 Approach

Energex applied the following approach to obtain the required information:

- POW016 reports for each year were used to identify the work orders that related to each of the NAMP lines.
- Cost data for the relevant work orders was then sourced using a SQL query that extracted a report from the Ellipse GL tables. The report included the following information:
  - YEAR;
  - DSTRCT_CODE;
  - ACCOUNT_CODE;
  - RESP_CTR;
  - ACTIVITY;
  - PRODUCT;
  - ELEMENT;
  - ELECAT;
  - WORK_ORDER;
  - PROJECT_NO; and

- AMOUNT.

- This data was extracted for activities codes 41100 (Inspections) and 41200 (Planned Maintenance), which represent maintenance activities.

- Cost data was allocated to the appropriate RIN categories by matching the cost for a relevant work order back to its assigned NAMP code, and therefore in turn to the primary maintenance activity in the RIN (based on the mapping of NAMP codes to RIN Asset Categories).

- Projects/work orders that had not been identified in the POW016 reports as being associated with specific NAMP codes were reviewed and assigned to NAMP codes where possible based upon the project / work order description.

19.4 Estimated Information

All information provided in Table 2.8.2 is Estimated Information.

19.4.1 Justification for Estimated Information

As the NAMP lines used to classify costs are not a direct match to the categories required in RIN table 2.8.2 the data is considered estimated. The NAMP lines are considered to be the best representation of the categories available to Energex.

19.4.2 Basis for Estimated Information

The costs were categorised into the categories required in 2.8.2 by mapping the Energex NAMP lines to the categories required.

19.5 Explanatory notes

Other Costs Supplementary information

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

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. c) 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 2014/15 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
2014/15	Storms struck ENERGEX on …	• Wednesday 19 November 2014 • Thursday 27 November 2014 • Monday 8 December 2014 • Thursday 18 December 2014 • Saturday 31 January 2015 • Friday 1 May 2015

- 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 2014/15 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 2014/15 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 – 2014/15	• Ellipse general ledger report (FIN073) • Annual Performance RIN and excel work files
Corporate Overhead – 2014/15	• 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, Meter Reading and Network Billing 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).

3) Adjustments applied in the preparation of the AP RIN which were not reflected in the general ledger report at the time have been incorporated to allow total overhead expenditure by functional area in the CA RIN to reflect the overhead reported in the AP RIN.

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 (2014/15):

- **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.

All information is Actual Information.

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	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 customer and nature of income or expense (Element). Energex uses the GL code to extract out only the labour related cost (Element) and standard control services (a combination of

Requirements (instructions and definitions)	Consistency with requirements
Regulatory Template 2.11. Energex must explain how it has grouped workers into these classification levels.	Responsibility Centre and Activity) figures. 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 sections 22.3.1 Assumptions and 22.3.2 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 are separately identified 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 22.3 – Methodology.
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 dollars 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 sections 22.3.1 Assumptions and 22.3.2 Approach.
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 sections 22.3.1 Assumptions and 22.3.2 Approach.

22.2 Sources

The following reports were extracted from the Ellipse system:

- General ledger balance ($ and hours) by labour category / element;
- General ledger transactions of 9 hour break 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 days and 10 days fortnightly work arrangement breakdown of internal labour;
- HRIS – Monthly Active FTE report; and
- Stand Down occurrences.

The following reports were extracted by the Energex Business Performance & Analysis team:

- Budget – Standard Labour available hours by labour category; and
- Budget – 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 (2014/15)	

Variable	Source
Average Productive Work Hours Per ASL - Ordinary Time	Standard labour rates and hours (Energex 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)
Average Productive Work Hours Hourly Rate Per ASL – Overtime	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

Refer to section 22.3.2 Approach below.

22.3.2 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 2014/15 Cost Allocation Methodology (CAM). The classification of the GL codes can be seen in Table 22.3:

Table 22.3: GL Code Classification

CA RIN Category	Energex GL Code
Corporate overhead	Corporate support cost

CA RIN Category	Energex GL Code
Network overhead	Metering Customer Call Centre DSM Direct Levies Network operations
Network direct	SCS Direct Opex 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

2) Table 23.4. 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 a system report is currently in development to enable the extraction of labour data against the AER categories directly from the Energex reporting software.

Table 23.4: Labour classification categories

		2014/15
Energex	**AER**	**Annual Hours/annum**
ADMN	SUPPORT STAFF	1,675
APPR	APPRENTICE	1,579
CONT	PROFESSIONAL	1,675
ELEC	SEMI PROFESSIONAL	1,579
EXE1	MANAGER	1,509
EXE2	SENIOR MANAGER	1,597
NEXE	PROFESSIONAL	1,675
PARA	SEMI PROFESSIONAL	1,675
PROF	PROFESSIONAL	1,675
PWKR	UNSKILLED WORKER	1,579
SPEB	MANAGER	1,675
SPVR	SEMI PROFESSIONAL	1,675
SYSO	SEMI PROFESSIONAL	1,675
TECH	SKILLED ELECTRICAL WORKER	1,579
EMT	EXECUTIVE MANAGER	1,597

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.

3) Once labour costs had been calculated the termination payments were added. These termination payments were obtained from HR data and verified against the GL and were added to the labour cost figures.

   Previously training costs and FBT were excluded as this data was unavailable for inclusion and/or deemed immaterial. As FBT costs are measurable they have been included in the current CA RIN for 2014/15. 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:

$$\frac{Number\ of\ Stand\ Down\ Occurrences}{Total\ ASLs}$$

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 to the largest labour category within each functional area. It should be noted this amount is considered immaterial (less than 1.5% 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 is not disaggregated by labour category, therefore the labour hire figures for Network Overheads and Network Directs were split into the labour categories using a pro-rata methodology based on the known total labour costs (85% Support Staff/3% Professional/13% Unskilled Worker – source: HR). The labour hire dollars calculated were divided by the productive ordinary time labour rate to obtain hours for each labour category.

Table 2.11.2 - Extra Descriptor Metrics For Current Year (2014/15)

The following process was used to calculate extra descriptor metrics for the 2014/15 regulatory year:

1) General ledger 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

No Estimated Information was reported.

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 (Intern/Junior Staff/Apprentice previously only reported 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 (Intern/Junior Staff/Apprentice previously only reported 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:

- **Overheads**
- **Fee Based Services**
- **Quoted Services**
- **Non-Network**
- **Vegetation Management**
- **Routine Maintenance**
- **Non-routine Maintenance**
- **Augmentation**
- **Connections**
- **Emergency Response**
- **Public Lighting**
- **Metering**
- **Replacement**

Estimated Information was provided for:

- **Routine Maintenance**
- **Non-routine Maintenance**
- **Augmentation**
- **Connections**
- **Public Lighting**
- **Metering**
- **Replacement**

All other information is Actual Information.

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 network/non-network asset or to provide a network/non-network service. *Direct materials* costs are attributable to a specific asset or service, cost centre, or work order, and exclude materials provided under external-party contracts. Includes: • the cost of scrap • normally anticipated defective units that occur in the ordinary course of the production process • routine quality assurance samples that are tested to destruction • the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	Refer above.
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: • 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.
Fee Based Services and Quoted Services – 2014/15	General ledger reports
Non-Network – IT and Communications	• SPARQ Solutions information based on invoices issued to Energex; • Accounting Entry Report per Ellipse; • Profit and Loss for SPARQ Solutions division from EPM for Cost of Sales, Telecommunications, Asset Usage Fee, Finance Fee & SLA • Capex expenditure per Regulatory accounts less Client Devices per Accounting Entry Report • Profit and Loss MOPEX RC 1020, account 4940 for 14/15 • 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

Variable	Source
	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 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	EPM Report – FIN077 Transactions Report
Non-routine Maintenance	EPM Report – FIN077 Transactions Report

Variable	Source
Augmentation	EPM Super User Query
Connections	EPM Super User Query
Emergency Response	EPM Report – FIN077 Transactions Report
Public Lighting	EPM Report – FIN077 Transactions Report, EPM Super User Query
Metering	Peace, Ellipse, ACS Quote Mode, Business Objects Reports
Replacement	EPM Super User Query

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 2014/15 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 (Substations, Feeders, Lines etc.) 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 2014/15, under financial activity codes C2010, C2510, C2550 and C2570 (less gifted assets). The expenditure figures were able to be broken up into the required cost categories; however the four activity codes only accounted for 92.8% of total connections spend in the 2014/15 financial years. An apportionment method was applied to the regulatory information based on percentage of totals extracted from the project ledger listing.

- For 2014/15 the capital costs were split by cost category by running a project cost report from EPM for the list of projects reported. The expenditure figures were able to be broken up into the required cost categories; however the total costs in the project ledger do not match the regulatory account values. As such an apportionment method was applied to the regulatory information based on percentage of totals extracted from the project ledger listing to ensure the total for connections expenditure balanced to regulatory accounts.

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 2014/15 period the maintenance costs were split using the mapping table in Appendix 5 and the EPM report sourced for template 4.1.2. The capital costs were split by cost category by running a project cost report from EPM for the list of projects reported. The expenditure figures were able to be broken up into the required cost categories; however the total costs in the project ledger do not match the regulatory account values. As such the percentages were used rather than the actual figures to ensure the total for connections expenditure balanced.

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.

Metering Expenditure Service Subcategory	Classification Methodology
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 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

Estimated Information was provided for:

- Routine Maintenance
- Non-routine Maintenance
- Augmentation
- Connections

- Public Lighting
- Metering
- Replacement

23.4.1 Justification for Estimated Information

Energex reporting of expenditure related to these variables is not directly aligned to the categories specified in the RIN. In order to comply with AER defined reporting requirements it was necessary to either:

- Apply an apportionment method to originally sourced data; or
- Map actual data or cost categories into AER defined categories.

Further information relating to the estimation of data reported for each of these variables can be found in the corresponding individual Basis of Preparations.

23.4.2 Basis for Estimated Information

For details of the Estimated Information please refer to the respective Basis of Preparation for each Regulatory Template.

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).
- Information will differ from information provided in the previous CA RIN submission as Energex employee funded vehicles have been excluded from the calculation as these costs are fully funded by employees and not funded by customers. Also the km's travelled was adjusted to reflect the average rather than the total as populated in the 2012/13 CA RIN submission.
- 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.

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. The exception is for related party costs that had been assessed to be immaterial and weren't reported in the annual regulatory accounts per the AER annual RIN requirements.

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.	
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.	SPARQ transactions are at cost so there is no margin.

24.2 Sources

Related party cost information is either from the annual regulatory accounts (also referred to as the Annual Performance Regulatory Information Notice – AP RIN) or from transaction listings from the Ellipse system which support the amounts reported in the AP RIN. Table 24.2 sets out the sources from which Energex obtained the required information.

Table 24.2: Information sources

Category	Source
Network Overheads	The AP RIN and/or its supporting workings
Corporate overheads	The AP RIN and/or its supporting work papers for SPARQ Solutions Opex.
Non-Network Expenditure – IT & Communications	SPARQ Solutions Capex and Opex from the AP RIN.
Augmentation, Replacement, Non-Network Expenditure – Buildings and Property	The AP RIN and/or its supporting work papers.

24.3 Methodology

Energex sourced the relevant information from the AP RIN and/or its supporting transaction listings and categorised the information as required in the CA RIN Table based on the nature of the transactions.

24.3.1 Assumptions

- Consistent with the definition provided in the CA RIN, Ergon Energy and Powerlink are also State-owned entities so have not been included as related parties.

24.3.2 Approach

- Energex categorised the relevant information from the AP RIN and/or its supporting work papers as required in the Input Tables. Where applicable, detailed transaction listings supporting the AP RIN work papers were obtained. 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. Where required, further confirmation would be sought from the Network Performance Manager based on the project numbers.

- Overhead costs are further sub-categorised into network overheads and corporate overheads based on the definitions used for CA RIN Template 2.10 - Overheads.

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

Year	CA RIN Table 2.12 related party cost total ($)	Related party cost total from the AP RIN $)	Variance ($)	Explanations for the variance
2015	220,205,958	110,926,452	109,279,506	Variance of $109,279,506 is made up of: - **$108,030,044.8** SPARQ operating costs that were in the general overhead pool are reported both in Corporate Overheads and Non Network Expenditure - ITC in this table. - **$1,249,461.2** Energy Impact costs were not reported in the AP RIN from 2013 as they were assessed to be immaterial while in 2011 and 2012 all costs were reported in the AP RIN regardless of materiality. They are therefore reported in this table for consistency.

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 2.3 (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 please refer to section 2.3 (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 2.3 (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 2.3 (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 has been taken into account in preparing Regulatory Template 4.1. For details please refer to section 2.3 (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 please refer to section 2.3 (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 please refer to section 2.3 (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

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.

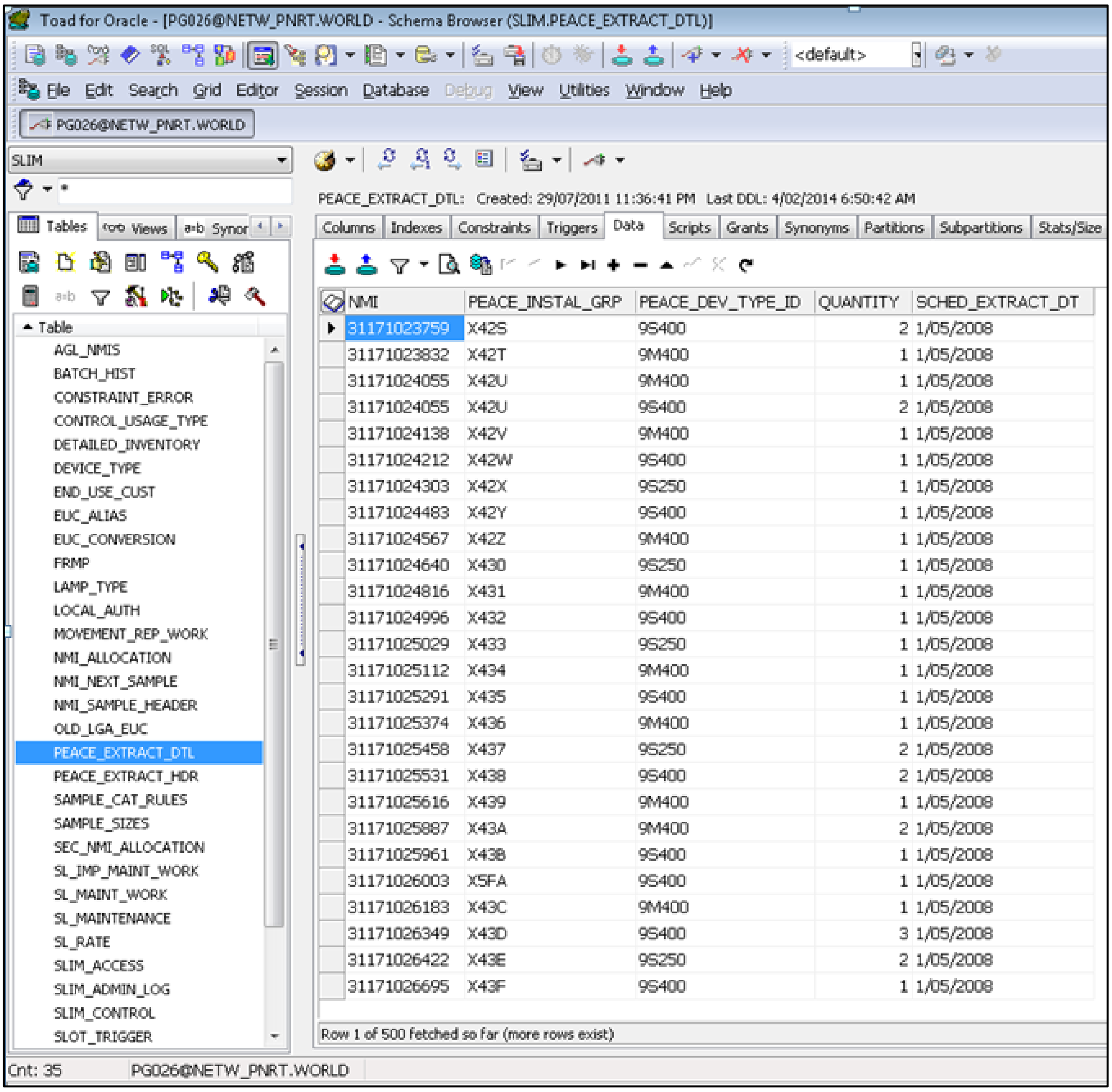
- Energex included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.

- 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

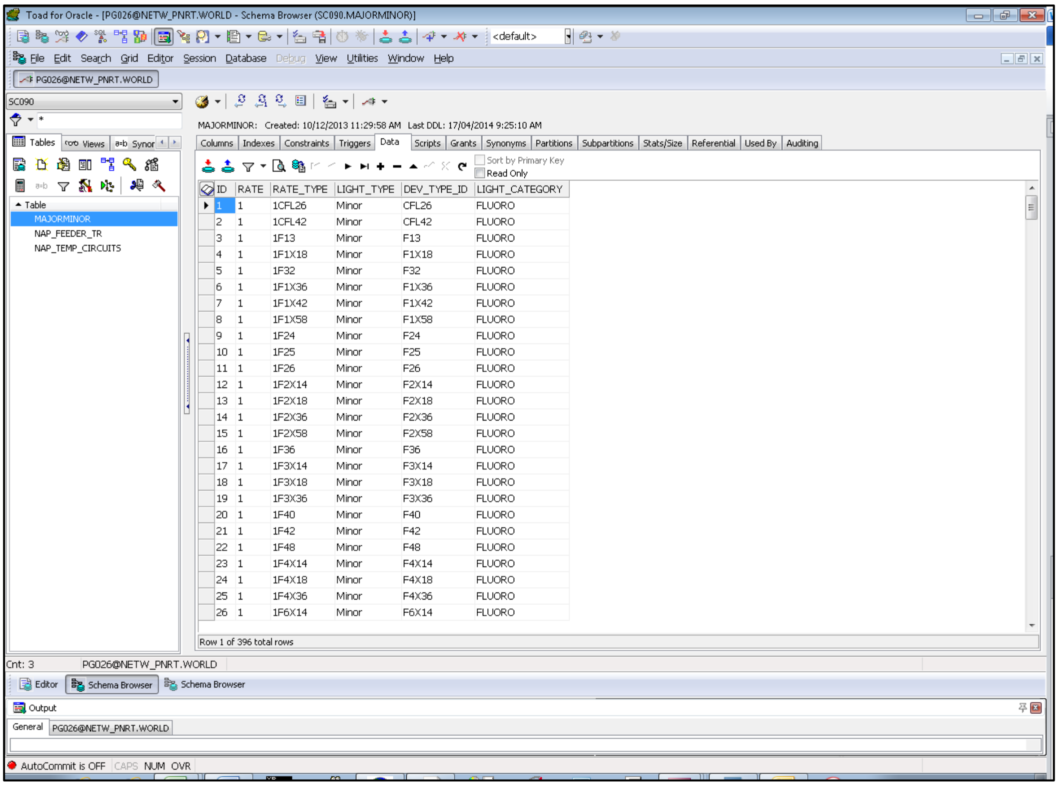
A report was extracted from both the SLIM database and the Oracle database to generate all the data required.

- 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 – Rate 1 – 2012-2013.sql' to provide the volume of Rate 1 streetlights broken down by streetlight category and by Major and Minor categories for the year 2014/15.

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 2014/15 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**

Estimated Information was provided for the following variables:

- **Total cost for light installation**
- **Major and minor road light volumes for light replacement**
- **Number of poles for light maintenance**
- **Mean days to rectify/replace assets**

All other 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

Requirements (instructions and definitions)	Consistency with requirements
	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).
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
The volume of minor roads lights installed, replaced and maintained	NFM, SLIM, Oracle
The number of poles installed, replaced and maintained	NFM, Ellipse
The total cost of lights installed, replaced and maintained	EPM, Ellipse, Corvu
The mean days to rectify / replace public lighting assets	Energex “Form 242”
The volume of GSL breaches	N/A

Variable	Source
The value GSL payments	N/A
The volume of customer complaints	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 2014/15.
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 2014/15 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 2014/15 the list of projects that incurred expenditure was taken from the EPM Report POW010. The list of projects included is based on the below activities and adjusted for projects split between asset categories based on the percentage allocated to Property Units in the POW010.

Activity Code	Description
C2560	CWDA Public Lighting
C3560	Street Lighting

2) These reports detailed all expenses and quantities booked against street lighting projects (both installations and replacements) in the 2014/15 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). All subdivision projects are considered gifted assets because they are fully funded by the developer. Any internally initiated projects which are not a "S" series and which are funded by greater than 90.0% by the Customer are considered gifted assets.

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 2014/15 the street lighting financial activities included both installation and replacement. The cost attributed to installation is the remaining costs after the known cost of replacement was subtracted. Considering only the replacement costs are certain actual costs, the remaining costs attributed to installations is considered an estimate.

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 derive an estimate for light replacements focussed on analysing two variables:
  - The volume of lights issued from the Procurement and Supply division
  - The volume of lights installed in the network.
- The difference between these two variables was used as proxy for replacements volumes. This was considered a reasonable assumption on the basis that street lighting projects contain two activities – installations and replacements.

Specifically, this process involved the following steps:

1) A report was extracted from Ellipse which provided a list of all streetlights issued by Procurement and Supply in 2014/15. This report provided all Rate 1 and Rate 2 public lights issued by Procurement and Supply, representing volumes for both replacement and installation projects.

2) The data was then filtered between Major and Minor light types. Rate 2 public lights relating to subdivisions were excluded from the data (identified by work order).

3) The total volume of public lighting for installations and replacements was established by summing the number of public lights issued by Procurement for Major and Minor light types.

4) A list of public light installation volumes was then obtained (the same report that was prepared for light installations) which provided the volume of all public lights installed in the network for Rate 1 and 2 categories (excluding gifted assets) by Major and Minor light types.

5) Replacement volumes were then derived by subtracting the installation volumes obtained in Step 4 from the installation and replacement volumes obtained in Step 3. This provided replacement volumes for Major and Minor light types.

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) Costs for street light replacements was derived from NAMP line SL04 - SL - Replace Unserviceable Pole. As activity C2545 is reported in the Repex Regulatory

Template 2.2, the costs associated with NAMP line SL04 have been excluded from the Repex Regulatory Template, and included in Public Lighting Regulatory Template for the total cost of light replacement.

2) The costs for 2014/15 were captured in activity C3560 – Street Lighting under NAMP line SL04. The costs for NAMP line SL04 have been subtracted from the total cost of C3560 (reported in the total cost for light installation).

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. The volumes for major road luminaires and minor road luminaires were extracted directly from the maintenance contract. Maintenance activities included the actual cost for luminaire maintenance (excluding luminaire replacement costs), streetlight circuit maintenance costs and streetlight patrol costs.

2) 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.

Number of poles maintained

1) The number of poles maintained has not been provided as Energex's pole maintenance contract does not distinguish between poles for street lights and poles for distribution lines.

2) It should be noted that Energex's current standard for the installation and replacement of street lights poles requires the installation of Base Plate Mounted (BPM) poles, which generally require no maintenance. At present approximately 2/3 of the population of dedicated street light poles are BPMs.

Total Maintenance Cost

1) A report was run from Mincom Ellipse Reporting which listed all street lighting projects that formed part of the maintenance works in 2014/15 under the financial activity code 41600 (street lighting).

2) This report detailed all expenses and quantities booked against street lighting maintenance projects in 2014/15. 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 Ellipse report.

Mean days to rectify / replace assets

Mean days to rectify/replace assets is estimated information. In order to provide an understanding of the approach used to determine the mean days to rectify / replace assets, it is first necessary to step out the process used by Energex to collect the data.

1) An electronic “Street Lighting Spot Replacement, Maintenance and Repair Sheet” (Form 242) is used by streetlight patrol officers to identify individual lights and streetlight circuits that are faulty. This form details the streetlight site number, location of the streetlight, the fault observed and the date of the patrol. One page can be used to record multiple lights needing repair.

2) After each patrol, an electronic copy of Form 242 in .pdf format is provided to Energex to record the date of the patrol on a spreadsheet. A copy of the form is also provided to the streetlight repairer. Once all the streetlight repairs are complete, the repairer returns the form back to Energex, detailing the date that all of the repairs were complete. A copy of the completed form is returned to Energex to record the completion date of the repairs. The patrol date is then subtracted from the repair date to get the number of days taken to repair the lights on the form. On by day streetlights (ie. 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.

3) Energex analysed the data inputted from each Form 242 and calculated the average time taken to rectify public lighting assets for the 2014/15 financial year.

It is important to note that the completion date on each Form 242 represents the date of the final repair job. As there are up to seven lights on each form, there can be a substantial variation between the time taken to repair the first light and the time taken to repair the seventh light. This means that the values inputted into Regulatory Template 4.1 will tend to overstate the time taken to rectify / replace streetlights.

Volume of customer complaints

1) Complaint data is derived from a feedback report 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) Monthly reports were collated for each financial year and the data was 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

The following figures are Estimated Information:

- Number of poles for all years for light installation;
- Total cost for 2011/12 to 2013/14 for light installation;
- Major and minor road light installation volumes for light replacement;
- Number of poles for 2011/12 for light replacement;
- Total cost for 2011/12 for light replacement;
- Number of poles for all years for light maintenance; and
- Mean days to rectify/replace assets.

26.4.3 Justification for Estimated Information

Energex does not capture costs or was unable to quantity data for the variables listed above. As such, Energex was required to prepare Estimated Information for these variables.

26.4.4 Basis for Estimated Information

Each of the variables that were estimated has been determined based on advice and assumptions made by subject matter experts who have daily exposure to public lighting issues. For full details of the estimation process, refer to the approach section above.

26.5 Explanatory notes

The increase in Minor Light Replacements in 4.1.2 to previous years can be attributed to the directive towards the removal of Mercury Vapour lights. Previously a MV light would be replaced when faulty. Energex are actively replacing these light types with Compact Fluoro light types as they come across them. Because of the assumptions used when calculating the light replacement figures, we have sought and received confirmation from our Street Light contractor that the increase in replacements is correct.

27. BoP 4.1.3 - Public Lighting Cost Metrics

The AER requires Energex to provide the following information, for the 2014/15 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 installed assets, replaced assets and maintained assets are Estimated Information.

All other information is Estimated 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	Corporate Ellipse estimation module
The average unit cost of lights replaced on major and minor roads	Corporate Ellipse estimation module
The average unit cost of lights maintained on major and minor roads	Street light maintenance contract

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.

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 2014/15 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 estimated the average unit cost of maintenance by major road types and minor road types.

2) Energex has determined the cost apportionment between major and minor road type categories based on the population of street lights at the end of the year for major and minor road streetlights. The estimated unit cost data is comprised of the following costs:
   a. Actual cost for luminaire maintenance (excluding luminaire replacement costs);
   b. Actual Streetlight circuit maintenance costs; and
   c. Actual Streetlight patrol costs.

27.3.2 Approach

Average unit cost of installation

The average unit cost of street light installations was estimated 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 8).

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 9).

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 7).

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 10).

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 10).

Average unit cost of replacement

The average unit cost of street light replacements was estimated 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 3).

2) Compact Fluorescent 32W – For the 2014/15 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 3).

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 3).

Average unit cost of maintenance

1) The unit cost data of maintenance is comprised of the following:
   a. Actual cost for luminaire maintenance (excluding luminaire replacement costs);
   b. Actual Streetlight circuit maintenance costs; and
   c. Actual Streetlight patrol costs.
2) The unit cost for each year for major and minor road streetlights was estimated by dividing the total cost for each year by the population of major and minor street lights at the end of the year.
3) The costs for these activities were sourced from Energex's streetlight maintenance contract, separated by major and minor road types. As noted above in the assumptions section, Energex has determined the cost apportionment between major and minor road type categories based on the proportion of the population of major and minor road luminaires in the 2014/15 regulatory year.

27.4 Estimated Information

All information is Estimated Information.

27.4.1 Justification for Estimated Information

Energex does not capture costs data for the variables in RIN Table 4.1.3. As such Estimated Information was provided for these variables.

27.4.2 Basis for Estimated Information

Each of the figures that were estimated has been determined based on advice and assumptions made by subject matter experts who have daily exposure to public lighting issues. For full details of the estimation process, refer to the approach given in the section above.

27.5 Explanatory notes

There are a number of variables that can affect the volumes/costs:

- 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 2014/15 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 2014/15 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

- **Meter Purchase**
- **Meter Testing**
- **Scheduled meter reading**
- **Special meter reading**

Estimated Information was provided for all other figures in table 4.2.2.

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.

Requirements (instructions and definitions)	Consistency with requirements
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 *metering services*. This includes work performed by third parties on behalf of Energex.	All information supplied is specific to 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.	Estimated information was required to redistribute expenditure and volumes amongst the estimated service sub categories based on assumptions.
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	Business Objects report- Meter Age Profile (MET003)
RIN Table 4.2.2 – Cost Metrics Expenditure	Ellipse, ACS AP RIN, Business Objects Reports: PUR012, INV023, INV14, INV003.
RIN Table 4.2.2 – Cost Metrics Volume	Ellipse, Business Objects Reports : DMA RIN 001 source table SRC-Meter

28.3 Methodology

28.3.1 Assumptions

The following assumptions have been applied to obtain the required information:

- The Meter Population figures in Table 4.2.1 are actual. Within these figures there are 2,168 meters where the Asset subcategory is unknown and these have been weighted across the type 6 subcategories.
- 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.
- 50% of meter queries and meter maintenance service orders result in a meter replacement.

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 collected by running SQL scripts in the Peace Customer Information System (CIS). These were based on the number of meters in-service as at 30th June 2015. These scripts also defined each meter by the model to identify which should be included in the poly phase, single phase, CT connected and DC connected categories. 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 plus the number as at 30 June 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 on the Metering Stock Codes. Stock codes containing the following codes were included in Meter Purchases 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;
  - 11618 - PRI REGN,KWH;10-60 AMP OR 15-100 AMP, 1 X 240 V,50 HZ;1 PH,2 WIRE,DIRECT CONN;S/RATE;3 TERM;WHITE MAIN COVER OR ACRYLIC COVER WITH LEGEND- ' BUILDERS;
  - 17451 - PRI REGN,KWH;240 V,50 HZ,15-100 AMP; 2 SINGLE PHASE MEASURING ELEMENTS, 2 CONTROL CIRCUITS;REAL TIME CLOCK RIPPLE RECEIVER;WITH OR WITHOUT LOAD;
  - 17722 - PRI REGN KWH;3 X 10-125 AMP,3 X 240 V, 50 HZ;3 PHASE,4 WIRE SOLID STATE PROGRAMMABLE;
  - 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;
  - 17726 - PRI REGN KWH;3 X 5-15/20 AMP,3 X 240 V, 50 HZ;3 PHASE;4 WIRE,TRANSF CONN,SOLID STATE ENERGEX PROGRAM SD;
  - 18606 - SINGLE PHASE KWH PLUG IN METER;240 V,50 HZ,100 AMP;MAIN CONDUIT;31.5 AMP CONTROLLED CIRCUIT;RIPPLE CONTROL RECEIVER;PROGRAMMED BY METER LAB;
  - 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;
  - 22247 - 3 PHASE;5-20 AMP;240 V;4 WIRE;CLASS 1.0; CURRENT TRANSFORMER CONNECTED;RJ45 PORT;INTERNAL MODEM POWER SUPPLY; 4 PULSE OUTPUT;2 AMP RELAY OUTPUT;
  - 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

- Refurbished meter volumes and expenditure figures were extracted from Ellipse Explorer application ELL00137.

- The figures provided are actual information in quantity and expenditure.

Table 4.2.2 – Meter Testing expenditure and volume

- SCS Meter Testing expenditure is actual and has been extracted from the general ledger in Ellipse. Report FIN077 was run in EPM for the financial year 2014/15 on activity 41700 (Customer Service) and sorted by work order description. Work orders containing the following descriptions were included in expenditure:
  - Fail/Repl Polyphase/CT Mtr
  - SC16 Mtr Test CT Meters
  - SC16 Mtr Test LV Polyphase/CT
  - Enhanced Site Inspection
  - Meter Test.
  - EGX Test CT's

- The ACS Meter Test expenditure was taken from product P070 (Meter Test) from the ACS 2014/15 Annual Performance RIN.

The volumes are the completed Meter Test service orders in FFA for the selected completion codes of 0,1,2,4,25,50,51,52, which were obtained from the Business Objects Report : DMA RIN 001.

Table 4.2.2 – Meter Investigation expenditure and volume

- The SCS expenditure has been extracted from the general ledger in Ellipse. Report FIN077 was run in EPM for the financial year 2014/15 on activity 41700 (Customer Service) and sorted by work order description. Work orders containing the following descriptions were included in expenditure:
  - Meter Investigation
  - Meter Query & Revenue Protection

- The ACS Meter Investigation expenditure was taken from product P070 (Meter Inspection) from the ACS 2014/15 Annual Performance RIN.

- The volumes are the completed Meter Investigation service orders in FFA for the selected completion codes of 0,1,2,4,25,50,51,52, which were obtained from the Business Objects Report : DMA RIN 001

An assumption has been made based on business experience and data that 50% of meter query service orders result in a Meter Replacement. Therefore, volumes and expenditure were transferred from the Meter Investigation category to Meter Replacements based on this assumption.

Table 4.2.2 – Scheduled Meter Reads expenditure and volume

- The volumes for scheduled meter reads are based on actual reads reported through EPM Business Objects reports. These reports extract the expenditure and volumes as collected by the meter readings systems and actual dollars paid to the contractor under the contract rates.

Table 4.2.2 – Special Meter Reads expenditure and volume

- The numbers for Special Meter reads are based on actual reads reported through EPM Business Objects reports.
- These reports extract the expenditure and volumes as collected by the meter readings systems and actual dollars paid to the contractor under the contract rates.

Table 4.2.2 – New Meter Installation expenditure and volume

- This SCS expenditure has been extracted from Ellipse. Report FIN077 was run in EPM for the financial year 2014/15 on activity C2585 (EID Metering Type 6) and sorted by work order description. Report FIN077 was also run for activity C2570 as this was the activity used prior to C2585 and there are some legacy bookings to old C2570 work orders. A total of $307,318.33 was taken from C2570 that related to New Meter Installations. Work orders containing the following descriptions were included in the expenditure:
  - A&A Install controlled load
  - A&A install Hot water
  - A&A Install PV meter
  - A&A Install CT Meter
  - A&A Install Meter
  - CT requests from stores Installs
  - New Connections Install Meter
- The ACS New Meter Installation expenditure was taken from the Capex expenditure for product P066 (Alterations and Additions to current metering equipment) from the ACS 2014/15 Annual Performance RIN.
- The volumes are the completed Meter Installation service orders in FFA for the selected completion codes of 0,1,2,4,25,50,51,52, which were obtained from the Business Objects Report : DMA RIN 001

All material costs for Type 6 meters including new installs, planned and reactive meter replacements were requisitioned to New Meter Installation work orders. Therefore, planned meter replacements and our estimated reactive meter replacements multiplied by the weighted average meter cost was transferred to the Meter Replacements expenditure category to ensure that these were recognised in the appropriate categories.

Table 4.2.2 – Meter Replacement expenditure and volume

- This expenditure has been extracted from Ellipse. Report FIN077 was run in EPM for the financial year 2014/15 on activity C2585 (EID Metering Type 6) and sorted by work order description. Report FIN077 was also run for activity C2570 as this was the activity used prior to C2585 and there are some legacy bookings to old C2570 work orders. A total of $172,947.83 was taken from C2570 that related to meter replacements. Work orders containing the following descriptions were included in the expenditure:
    - SC14 Meter Compliance Replace,
    - Replace Meter (following test program),
    - Alterations and Additions Meter Upgrade.
- The volumes are the completed Meter Replacement service orders in FFA for the selected completion codes of 0,1,2,4,25,50,51,52, which were obtained from the Business Objects Report : DMA RIN 001

All material costs for Type 6 meters including new installs, planned and reactive meter replacements were requisitioned to New Meter Installation work orders. Therefore, planned meter replacements and our estimated reactive meter replacements multiplied by the weighted average meter cost was transferred from the New Meter Installation category to the Meter Replacements expenditure category to ensure that these were recognised in the appropriate category.

Meter Maintenance and Meter Query work orders do not always result in such work being carried out. Based on data and general business knowledge, approximately 50% of meter maintenance and meter query service orders result in a meter replacement. Therefore, 50% of these work orders expenditure and volumes are estimated to be Meter Replacements and have been transferred from the Meter Maintenance and Meter Investigation categories.

Table 4.2.2 – Meter Maintenance expenditure and volume

- The SCS expenditure has been extracted from Ellipse. Report FIN077 was run in EPM for the financial year 2014/15 on activity 41700 (Customer Service) and sorted by work order description. Work orders containing the following descriptions were included in expenditure:
    - A&A Remove Meter,
    - Check Timeswitch,
    - Maintain Meter,
    - Repl Meter Seal.
- The ACS Meter Maintenance expenditure was taken from the opex expenditure for product P066 (Alterations and Additions to current metering equipment) from the ACS 2014/15 Annual Performance RIN.

- The volumes are the completed Meter Maintenance service orders in FFA for the selected completion codes of 0,1,2,4,25,50,51,52, which were obtained from the Business Objects Report : DMA RIN 001

An assumption has been made based on business experience and data that 50% of meter maintenance services orders result in a Meter Replacement. Therefore, volumes and expenditure were transferred from this category to Meter Replacements based on this assumption.

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

- No expenditure has been reported in other Metering expenditure.

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

- All material costs for Type 6 meters including new installs, planned and reactive meter replacement were requisitioned using New Meter Installation work orders. Therefore, planned meter replacements and our estimated reactive meter replacements multiplied by the weighted average meter cost (based on Stock Issue report INV014 & INV023) were transferred from the New Meter Installation to the Meter Replacements expenditure category to ensure that these were recognised in the appropriate category.

- An assumption is made that 50% of meter query service and work orders (Meter Investigation category) and 50% of meter maintenance service and work orders (Meter Maintenance category) result in a meter replacement, based on business experience and data. This is not reflected in the volumes or the expenditure in the ledger as the service order is completed as it is initially raised and field workers book their time to meter maintenance and meter query work order despite doing a replacement. Therefore, 50% of expenditure and volumes to meter query work and service orders (Meter Investigation category) and 50% of expenditure and volumes to meter maintenance work and service orders (Meter Maintenance category) are transferred to the Meter Replacement category

28.4.2 Justification for Estimated Information

- All information was gathered initially using actual expenditure in the Ellipse general ledger and volumes extracted from DMA. It became apparent that when reporting solely on actual records per Ellipse and DMA that something was amiss due to abnormal unit rates. Therefore, we were required to make assumptions to categorise expenditure and volumes into the appropriate category based on business knowledge and data.

- Estimation of expenditure and volumes was required because of the inability to change the service order type once issued in the field and therefore the actual category of work completed can be different to what is recorded in our systems. Also, when meters are requisitioned, there is no knowledge on whether the meters will be used for New Meter Installations or Meter Replacements so all meters are requisitioned to New Meter Installation work orders and thus an estimate is required to calculate the material value for the Meter Replacement category.

28.4.3 Basis for Estimated Information

- An estimate for Reactive Meter Replacements was calculated based on the assumption that 50% of meter query and meter maintenance service orders result in a meter replacement. This was based on business knowledge and data.

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 2014/15 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.	As per the current annual RIN, 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	Audited Annual RIN submitted to the Australian Energy Regulator
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:

Expenditure Dollar Values

- The audited Annual RIN for 2014/15 provided the detailed expenditure figures required for each of these years in Category Analysis RIN template 4.3.

Volume

- As information on volumes is no longer required as part of the Annual RIN, all volumes were obtained from the PEACE report MSR246. These volumes represent the number of services performed, including all de-energisations and re-energisations.

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

The majority of re-energisations in 2014/15 were undertaken by contractors, hence the lower unit cost.

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 2014/15 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.	As per the current annual RIN, 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	Audited Annual RIN submitted to the Australian Energy Regulator
Volumes for quoted services	EPM Report – Quoted Services Volume & Revenue : 128178 : 134034

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:

Expenditure Dollar Values

- The audited Annual RIN for the 2014/15 regulatory year provided the detailed expenditure figures reported in Regulatory Template 4.4.

Volume

- As information on volumes is no longer required as part of the Annual RINs, all volumes were obtained from the EPM Report – Quoted Services Volume & Revenue : 128178 : 134034; and
- These volumes represent the number of services performed.

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

Energex's accounting treatment for Large Customer Connections is governed by the contracts with the customers. As such, transactions are similar in nature to SCS capex projects that receive capital contributions. Therefore all Large Customer Connection projects are treated as capex with expenditure recognised as incurred. Revenue cannot be recognised until the asset is fully constructed and energised.

After hours provision of any fee-based service (excluding re-energisations)

System limitations do not allow Energex to recognise the expense for after-hours fee based services separately from the business hours expense. This means that after hours provision of fee-based services is not separately quantifiable.

Supply abolishment – complex

Supply Abolishment Complex within Quoted Services has no volumes recorded against the expenditure as costs were transferred from an product to be used from the 1 July 2015 and no volumes identified from the transactions (P092 to P056).

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:

- **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)**
  - **Pole mounted; < = 22KV ; < = 60 KVA ; Single Phase**
  - **Pole mounted; < = 22KV ; > 60 KVA and < = 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**
  - **Pole mounted; > 22 KV ; > 600 KVA**
  - **Kiosk mounted; < = 22KV ; > 60 KVA and < = 600 KVA ; Multiple Phase**
  - **Kiosk mounted; < = 22KV ; > 600 KVA ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; < 22 KV ; < = 60 KVA ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; < 22 KV ; > 60 KVA and < = 600 KVA ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; < 22 KV ; > 600 KVA ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; > = 22 KV & < = 33 KV ; < = 15 MVA**
  - **Ground Outdoor / Indoor Chamber Mounted; > = 22 KV & < = 33 KV ; > 15 MVA**

and < = 40 MVA

  – Ground Outdoor / Indoor Chamber Mounted; > = 22 KV & < = 33 KV ; > 40 MVA
  – Ground Outdoor / Indoor Chamber Mounted; > 33 KV & < = 66 KV ; > 15 MVA and < = 40 MVA

- 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
  – Brackets; Major Road (Year 1910/11)
  – Brackets; Minor Road (Year 1910/11)
  – 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	The categories were reported in accordance with the values in Regulatory Template 2.2 – Repex

Requirements (instructions and definitions)	Consistency with requirements
Template.	
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)	NFM
Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)	NFM
Underground Cables By: Highest Operating Voltage	NFM
Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV)	NFM
Switchgear By: Highest Operating Voltage ; Switch Function	NFM
Public Lighting By: Asset Type ; Lighting Obligation	NFM

31.3 Methodology

All data was extracted from NFM. 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 2015.

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 some 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, Link Pillar 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:

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

1) A report was extracted from NFM 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 and also removes all duplicate entries that may be inherent within the NFM database.

2) The report output from NFM was then analysed in Excel to produce the figures required in table 5.2.1. Adjustments were required to be made for:

   a. Poles dated pre-1920.

   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 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 as a result all assets with an age falling within this period were prorated into the pre spatial NFM period 1970 to 1999.

Table 31.3: Prorata of assets with install date <=1920

Poles	Null Date	1900-1920
< = 1 KV; WOOD	0	2361
> 1 KV & < = 11 KV; WOOD	1	949[1]
> 11 KV & < = 22 KV; WOOD	0	0
> 22 KV & < = 66 KV; WOOD	0	124
> 66 KV & < = 132 KV; WOOD	0	2
> 132 KV; WOOD	0	0
< = 1 KV; CONCRETE	0	78
> 1 KV & < = 11 KV; CONCRETE	0	75
> 11 KV & < = 22 KV; CONCRETE	0	0
> 22 KV & < = 66 KV; CONCRETE	0	8
> 66 KV & < = 132 KV; CONCRETE	0	0

Poles	Null Date	1900-1920
> 132 KV; CONCRETE	0	0
> 1 KV & < = 11 KV; STEEL	28	40
> 11 KV & < = 22 KV; STEEL	0	0
> 22 KV & < = 66 KV; STEEL	0	0
> 66 KV & < = 132 KV; STEEL	0	0
> 132 KV; STEEL	0	0
1. This value contains a single pole that doesn't have a material type.		

4) Some poles had material descriptions other than what was specified in the template. These were treated as follows.

a. Poles that have a material type of plastic were excluded as follows:

Plastic Poles	Quantity
< = 1 KV	13
> 1 KV & < = 11 KV	11
> 22 KV & < = 66 KV	0
> 66 KV & < = 132 KV	0

b. Aluminium poles were combined with steel poles as follows:

Aluminium Poles	Quantity
< = 1 KV	318
> 1 KV & < = 11 KV	0
> 22 KV & < = 66 KV	0
> 66 KV & < = 132 KV	0

All poles that cannot be allocated a material type or age because they do not have a specification recorded in NFM were prorated a material based on the ratio of existing known material types; refer to Table 31.4 for numbers of unknown poles as at 30 June 2015.

Table 31.4: Unknown Pole Numbers

Asset Group	Unknown Quantity	Pro Rata		
Pole Max Voltage		Concrete	Steel	Wood
< = 1 KV	860	1%	45%	54%
> 1 KV & < = 11 KV	231	3%	0%	97%
> 22 KV & < = 66 KV	32	3%	2%	95%
> 66 KV & < = 132 KV	0	35%	11%	54%

5) 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.

Table 31.5: Quantities of Staked and Nailed Poles Assigned Install Dates in Error

Asset Category	Quantity in Error
< = 1 KV; STAKED	3272
> 1 KV & < = 11 KV; STAKED	2202
> 11 KV & < = 22 KV; STAKED	0
> 22 KV & < = 66 KV; STAKED	143

Due to the short life of a pole nailing it was deemed that a linear representation would skew the data in the wrong direction. For this reason the following percentages were applied:

Pole Nailing Allocation	Percentage
2001	35%
2000	28%
1999	22%
1998	15%

6) 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.

Table 31.6: Quantities of Steel LV Poles Prorated

LV Steel Poles	Quantity
1900 – 1970	24
Null Date	28

7) All poles with no voltage such as cross street and bollard poles were allocated to the <=1KV category

8) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor manual adjustments to ensure that rounding errors do not occur from the proration. All manual changes only affect the year with the maximum number of assets assigned to it by a maximum of one asset. Where more than one asset is needed to balance the rounding error then the next maximum number of assets is modified by a maximum of one and so on until the value is balanced. Where multiple years share identical number of assets then the modification occurs from oldest to the youngest asset.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

1) Energex does not have complete installation records for overhead conductors. As such, no actual age information was available and the overhead conductor age was estimated using the applicable pole age.

2) A report was run from NFM 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.

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 31.7: Volumes of Customer Owned Conductors

Customer Conductor	Quantity
Overhead	8.07

5) The following methodology was then used to estimate 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.

   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 then inherited the maximum pole age that is acceptable within the particular grouping. Where an acceptable pole age cannot be found, the adjacent circuits were analysed to determine if an acceptable age profile could be found. Where an acceptable age profile could not be found all conductors with a metric category were allocated an age of 1974-75 and all conductors with an imperial category were allocated an age of 1944-45.

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. All manual changes only affect the year with the longest length by a maximum of one kilometre. Where more than one kilometre is needed to balance the rounding error then the next maximum length is modified by a maximum of one kilometre and so on and so forth until the value is balanced. Where multiple years share identical lengths then the modification occurs from oldest to the younger asset.

Underground Cables By: Highest Operating Voltage

1) Energex does not have complete installation records for underground cables. In the late 1990's when Energex conducted its network data capture exercise, the business case was based on operational and planning benefits which did not require asset management information such as installation date or any history to be kept for cables. As such, no actual age information was available and the underground cable age was estimated using the age of connected assets.

2) A report was run from NFM 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 conductors 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 31.8: Volumes of Customer Owned Cable

Customer Conductor	Quantity (km)
Underground Cable	21.70

5) The following methodology was used to estimate 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.

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 minimum age of the connected assets that was acceptable within the particular grouping. Where an acceptable asset age could not be found, the adjacent circuits were analysed to determine if an acceptable age profile could be found. 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) The methodology 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 table below outlines the parameters used to distribute these values.

Table 31.9: Parameters used to Distribute Underground Network Assets

Title	LV	11KV
Base Year	2002	2000
Original Length	5,880km	1,520km
Base Year Allocation *This allocation is based on total expected trend, for this period, while also correcting rounding errors*	92km	97km
Available amount to allocate	5,778km	1,423km
Allocation Range	1985-2002	1985-2000
Number of years	18yrs	15yrs[1]
Allocation per year	321km	94km
[1] Year 1999 was not allocated an additional amount as total shown was within tolerances.		

7) Due to rounding errors inherent within the above methodology, some cables had to be manually added to or subtracted from to ensure consistency of the final figure. All manual changes were added to or subtracted from only once from any particular year, with the max number of assets within a particular asset group being added to or subtracted from first, then followed by the second and third largest years and so forth. Where equal values exist between two years then the modifications are updated from the oldest to youngest assets.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

1) A report was run from NFM which counted the number of transformers broken down by:
    a. Mounting type.
    b. Capacity.
    c. Phasing.

    Transformers recorded in NFM as being connected to the network 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 2015) 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) This report was imported into excel and transformers with the following unknown values were required to be adjusted for:
    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) Transformers with an unknown rating were allocated a rating based on existing percentage breakdown of assets. Please see below table for details.

5) Transformers that have an unknown date were allocated an age based on existing percentage breakdown. Table 31.10 illustrates the quantity of transformers without a date that were prorated in the age profile with the assets that had no rating.

Table 31.10: Quantity of Transformers Prorated

Transformer Type	Percentage Unknown Rating	Unknown Rating Quantity	Unknown Age Quantity	Count of Assets to Age
POLE MOUNTED ; < = 22KV ; < = 60 KVA ; SINGLE PHASE	17.25%	60	1188	1248
POLE MOUNTED ; < = 22KV ; > 60 KVA and < = 600 KVA ; SINGLE PHASE	0.02%	0	0	0
POLE MOUNTED ; < = 22KV ; > 600 KVA ; SINGLE PHASE	0.00%	0	0	0
POLE MOUNTED ; < = 22KV ; < = 60 KVA ; MULTIPLE PHASE	18.62%	65	876	941
POLE MOUNTED ; < = 22KV ; > 60 KVA and < = 600 KVA ; MULTIPLE PHASE	64.11%	223	4268	4518
POLE MOUNTED ; < = 22KV ; > 600 KVA ; MULTIPLE PHASE	0.00%	0	0	0
POLE MOUNTED ; > 22 KV ; < = 60 KVA	57.78%	2	0	2
POLE MOUNTED ; > 22 KV ; > 60 KVA and < = 600 KVA	42.22%	1	0	1
POLE MOUNTED ; > 22 KV ; > 600 KVA	0%	0	0	0
POLE MOUNTED ; > 22 KV ; < = 60 KVA	0.00%	0	0	0
POLE MOUNTED ; > 22 KV ; > 60 KVA and < = 600 KVA	0.00%	0	0	0
POLE MOUNTED ; > 22 KV ; > 600 KVA	0.00%	0	0	0
KIOSK MOUNTED ; < = 22KV ; < = 60 KVA ; SINGLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22KV ; > 60 KVA and < = 600 KVA ; SINGLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22KV ; > 600 KVA ; SINGLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22KV ; < = 60 KVA ; MULTIPLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22KV ; > 60 KVA and < = 600 KVA ; MULTIPLE PHASE	78.24%	117	753	870
KIOSK MOUNTED ; < = 22KV ; > 600 KVA ; MULTIPLE PHASE	21.75%	33	216	249
KIOSK MOUNTED ; > 22 KV ; < = 60 KVA	0.00%	0	0	0

Transformer Type	Percentage Unknown Rating	Unknown Rating Quantity	Unknown Age Quantity	Count of Assets to Age
KIOSK MOUNTED ; > 22 KV ; > 60 KVA and < = 600 KVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 KV ; > 600 KVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 KV ; < = 60 KVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 KV ; > 60 KVA and < = 600 KVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 KV ; > 600 KVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; < = 60 KVA ; MULTIPLE PHASE	0.02%	1	0	1
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 60 KVA and < = 600 KVA ; MULTIPLE PHASE	17.62%	23	29	52
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 600 KVA ; MULTIPLE PHASE	82.34%	107	413	512
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; < = 15 MVA	50.33%	17	10	27
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; > 15 MVA and < = 40 MVA	49.67%	17	10	27
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 KV & < = 33 KV ; > 40 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < = 66 KV ; < = 15 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < = 66 KV ; > 15 MVA and < = 40 MVA	100.00%	1	0	1
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < = 66 KV ; > 40 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < = 132 KV ; < = 100 MVA	95.57%	13	1	14
GROUND OUTDOOR / INDOOR	4.31%	1	0	1

Transformer Type	Percentage Unknown Rating	Unknown Rating Quantity	Unknown Age Quantity	Count of Assets to Age
CHAMBER MOUNTED ; > 66 KV & < = 132 KV ; > 100 MVA				
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 KV ; < = 100 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 KV ; > 100 MVA	0.00%	0	0	0

6) Transformers with unknown phasing were prorated into the known totals for each phasing category and then prorated across the years.

7) 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. All manual changes only affect the year with the maximum number of assets assigned to it by a maximum of one asset. Where more than one asset was needed to balance the rounding error then the next maximum number of assets was modified by a maximum of one and so on and so forth until the value was balanced. Where multiple years share identical number of assets then the modification occurs from oldest to the youngest asset.

Switchgear By: Highest Operating Voltage: Switch Function

1) A report was run within NFM 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, Link Pillar 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 2015) 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 2015.

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 assets captured during this period were allocated based on the mean life of the asset type.

Customer Conductor	Quantity (km)
Total to Allocate 1999-2002	66,163
Base Allocation 2002	1,000
Base Allocation 2001	1,000
Base Allocation 2000	1,000
Base Allocation 1999	1,000
Available Allocation	62,163
Mean Age	48
Current Year	2,015
Base Year	2,003
Number of Year No Allocation Required	11
Years to Allocate	37
Allocate Till	1,966
Quantity Allocated Each Year	1,680

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. All manual changes only affect the year with the maximum number of assets assigned to it by a maximum of one asset. Where more than one asset was needed to balance the rounding error then the next maximum number of assets was modified by a maximum of one and so on and so forth until the value was balanced. Where multiple years share identical number of assets then the modification occurs from oldest to the youngest asset.

Public Lighting By: Asset Type; Lighting Obligation

1) A report was extracted from NFM 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 1980 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 2006 for Mercury Vapour and 2010 for other types) have been accumulated and applied consistently into each year.

Type	Mercury	Other
Average life span	5yr	4yr
Major Quantity	2,523	71,719

Type	Mercury	Other
Minor Quantity	130,978	35,367
Major Allocation per Year	504.6	17,929.75
Minor Allocation per Year	26,195.6	8,841.75

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.

Type	Pre 1970 poles
Major	370
Minor	1056

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.

31.4 Estimated Information

Estimated Information was provided for the following line items:

- 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):
  - Pole mounted; < = 22KV; < = 60 KVA; Single Phase.
  - Pole mounted; < = 22KV; > 60 KVA and < = 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.
  - Pole mounted; > 22 KV; > 600 KVA.
  - Kiosk mounted; < = 22KV; > 60 KVA and < = 600 KVA; Multiple Phase.
  - Kiosk mounted; < = 22KV; > 600 KVA; Multiple Phase.
  - Ground Outdoor / Indoor Chamber Mounted; < 22 KV; < = 60 KVA; Multiple Phase.
  - Ground Outdoor / Indoor Chamber Mounted; < 22 KV; > 60 KVA and < = 600 KVA; Multiple Phase.
  - Ground outdoor / Indoor Chamber Mounted; < 22 KV; > 600 KVA; Multiple Phase.
  - Ground Outdoor / Indoor Chamber Mounted; > = 22 KV & < = 33 KV; < = 15 MVA.
  - Ground Outdoor / Indoor Chamber Mounted; > = 22 KV & < = 33 KV; > 15 MVA and < = 40 MVA.
  - Ground Outdoor / Indoor Chamber Mounted; > = 22 KV & < = 33 KV; > 40 MVA.
  - Ground Outdoor / Indoor Chamber Mounted; > 33 KV & < = 66 KV; > 15 MVA and < = 40 MVA.
  - 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.
  - Brackets; Major Road (Year 1910/11).
  - Brackets; Minor Road (Year 1910/11).

- Lamps; Major Road.
- Lamps; Minor Road.

31.4.1 Justification for Estimated Information

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

All data for poles was extracted directly from the NFM system, however, certain anomalies in this data were required to be adjusted for manually. These adjustments related to:

- Poles dated pre-1920.
- Allocation of poles made of other or unknown materials.
- Errors in staked and nailed poles.
- Pre-1970 Steel LV poles.
- Poles without an assigned voltage (cross street and bollard poles).

Due to the inherent prorating methodologies and assumptions used in these adjustments, all data for poles was estimated.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

- Energex does not have complete installation records for overhead conductors. As such, no actual age information was available and the overhead conductor age was estimated using the applicable pole age.

Underground Cables By: Highest Operating Voltage

- Similar to the overhead conductors above, Energex does not have complete installation records for underground cables. As such, no actual age information was available and the underground cable age was estimated using the age of connected assets.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

- The line items that have been estimated are stated above. These line items were estimated due to a number of transformers lacking data that would allow them to be classified. The unknown data was in relation to:
  - Transformers with unknown ratings.
  - Transformers with unknown dates.
  - Transformers with unknown phasing.
- No other source data was available for these transformers and they were required to be spread across the transformers with complete data.

Switchgear By: Highest Operating Voltage; Switch Function

- Some switchgear had a date prior to 1910/11 which was deemed to be incorrect but no other date information was available to be used to assign a date. These assets were therefore prorated from 1912 to 2015 where data was present.

Public Lighting By: Asset Type; Lighting Obligation

- 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.

- 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.

Other By: DNSP defined: categories Category - Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number Of Phases (at LV):

- See section Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV) for details.

31.4.2 Basis for Estimated Information

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

- The following adjustments were made to the pole data extracted from NFM:
  - Poles dated pre-1920.
  - Allocation of poles made of other or unknown materials.
  - Errors in staked and nailed poles.
  - Pre-1970 Steel LV poles.
  - Poles without an assigned voltage (cross street and bollard poles).

- For the detailed methodology of each of the adjustments please refer to the approach section above.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

- For the detailed estimation methodology of how overhead conductor age was based on the pole age, please refer to the approach section above.

Underground Cables By: Highest Operating Voltage

- For the detailed estimation methodology of how underground conductor age was based on the age of connected assets, please refer to the approach section above.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

- The figures that were estimated incorporate some transformers with unknown data. These transformers were prorated across each category and/or year based on the quantities of transformers that were able to be fully categorised. For full details of the estimation please refer to the approach section above.

Switchgear By: Highest Operating Voltage; Switch Function

- Some switchgear had a date prior to 1910/11 which was deemed to be incorrect but no other date information was available to be used to assign a date. These assets were therefore prorated from 1912 to 2015 where data was present.

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. For full details please refer to the approach section above.

- 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.

Other By: DNSP defined: categories Category - Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number Of Phases (at LV):

- See Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV) for further details.

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 then entered against NAMP's in Ellipse for corporate reporting visibility in EPM)
Service Cable - New net NMIs connected as Overhead	PEACE EOM reports

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 estimate 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 conductors) 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 17 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 Table 32.3 below:

Table 32.3: Expect Age Range for Cable Types

CABLE_TYPE	Age range (yrs)
B (Bare Open)	Any
N (Concentric Neutral)	28-39
O (Open wire Neutral)	39+
P (Parallel web)	18-39
T (Twisted multiphase)	18-39
X (XLPE)	0-18
XMT (XLPE Mitti)	8-10
Y (4x95 XLPE)	0-18

CABLE_TYPE	Age range (yrs)
UNKNOWN	Any

4) 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.

5) 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 leaves a ‘net’ new number of NMIs with overhead service cable.

6) 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 overall customer base, where 8.2% of customers are Commercial & Industrial and the balance Residential.

7) Replacement information is broken into:
   a. XLPE Mitti service replacements
   b. PVC and twisted service replacements
   c. Open wire and concentric neutral services.

   These replacements are evenly distributed and removed from the previous year’s population.

32.4 Estimated Information

No estimates were used. Figures from a) the MARS Database as a baseline b) the Replacement Spreadsheet and c) End Of Month (EOM) reports from PEACE are considered actual rather than estimated information.

32.4.1 Justification for Estimated Information

Not applicable.

32.4.2 Basis for Estimated Information

Not applicable.

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**

All figures are Estimated Information.

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. Life cycle costs of the asset include those associated with the design, implementation, operations, maintenance, renewal and rehabilitation, depreciation and cost of finance.	Demonstrated in section 33.3 (Methodology).
Where Energex provides asset sub-categories corresponding to the prescribed	Demonstrated in

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	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	NFM
	ALL Refurbished poles wood	NFM
	ALL Poles – Steel and Concrete	Engineering Assessment
Overhead Conductor	< ≈ 1 KV	Engineering Assessment
	> 1 KV & < ≈ 11 KV	
	> 11 KV & < ≈ 22 KV ; SWER	

Asset Group	Variable	Source
	> 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 v3.0 EGX CBRM - 33kV Oil Filled Cables v3.0 EGX CBRM - 33kV Solid Cables v3.0
	> 66 KV & < ≈ 132 KV	Energex CBRM - 110kV Oil Filled Cables v3.0 Energex CBRM - 110kV Solid Cables v3.0
Service Lines	ALL	Engineering Assessment
Transformers	POLE MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; SINGLE PHASE	Energex CBRM - Pole Mounted TX v3.0
	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 v3.0
	KIOSK MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	
	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 v3.0
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 60 KVA AND < ≈ 600 KVA ;	

Asset Group	Variable	Source
	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 TX v3.1
	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 TX v3.1
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < ≈ 132 KV ; > 100 MVA	
	REGULATOR ; SUBSTATION < = 22kV	EGX CBRM- Regulators V2015.1
	REGULATOR ;DISTRIBUTION < = 22kV	
	REGULATOR ; SUBSTATION > = 22kV	
Switchgear	< ≈ 11 KV ; CIRCUIT BREAKER	EGX CBRM 11kV CB v3.3 Energex CBRM - reclosers v3.0
	> 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 v3.2
	> 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 v3.1
	> 66 KV & < ≈ 132 KV ; OPERATIONAL SWITCH	Engineering Assessment
Public Lights	Luminaires	Manufacturer’s specification
	Brackets and Poles	Network Asset Management documentation
	Lamps	Public lighting maintenance contract and SLIM/NFM (Oracle)

Asset Group	Variable	Source
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS	ALL	Engineering Assessment and CBRM

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 in November / December 2013 for developing asset replacement programs for the forthcoming regulatory control period and is based on various asset classes in the network. 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 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 low voltage steel poles was assumed to be the same as 11kV steel 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.
- Steel poles include steel mono poles and steel lattice towers.

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 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.

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 Poles and Refurbished Wood 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 NFM listing the date of installation and date of replacement. Data was provided in an Access database and 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 ellipse.
- 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 was replaced 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 on the basis that they did not represent condition based replacements, namely:
  - Replacement age of wood poles >66kV: these poles were excluded due to the dataset being too small to provide a representative economic life.
  - Poles replaced <=5 years from installation date: poles replaced within 5 years of installation are unlikely to be due to the condition of the asset. As a consequence, these poles were removed from the analysis.
- The economic life for each asset category was then determined by calculating the average service life across all poles in the asset category.
- Only a small dataset was available for the asset category, “> 66 KV and < ≈ 132 KV; WOOD”, and this data did not provide a representative economic life. In the absence of an appropriate dataset, the average asset life for “> 66 KV and < ≈ 132 KV; WOOD” was determined by calculating the average asset life across all wood poles.

Refurbished wood poles

- 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 replacement age from date of nailing. The data was included in the template as Refurbished Wood Poles in accordance with the AER’s guidance.

Concrete and Steel 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.
- A data set was not available for steel pole actual replacement life due to their long service life and ability to extend life through ongoing inspection and preventive maintenance programs. As a result, the economic life for steel poles was estimated based on manufacturer's specification and general industry expectations. This data set does not include public lighting poles.

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 poles and brackets was calculated based on the weighted average age of the population of:
  - Base Plate Mounted poles, which have an economic life of 50 years (this was based on Energex's Asset Management Division expectations. Note that the population of Base Plate Mounted poles was relatively young compared to the anticipated economic life, hence there was limited failure trend data available).
  - Buried in Ground poles, which have an economic life of 30 years (this was based on failure trend occurring at approximately 25 years of age as advised from Energex's Asset Management Division).

- 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 based on the actual replacement rate of lamps sourced from the maintenance contract. The following steps were applied (separately for major and minor road lamps):

1) The volume of lamp replacements for 2014-15 was collated from the maintenance contract history spreadsheet.

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 2014-15). 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 2015, a query was run to extract all current streetlights. The parameters used were:

  - The streetlight slot was current as at 30.6.15
  - The rate of the light was either 1 or 2

3) The lamp economic life was then calculated by dividing the 2014-15 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)

Asset Category	Sub - Category
	Multiplex (including MPLS nodes)
COMMUNICATIONS SITE INFRASTRUCTURE	Tower/pole
	Battery
	Charger
	Diesel
	Air conditioning
	Site security
	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. 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 of the motor generator and SFU modified expected life from the CBRM model (EGX CBRM AFLC v3.7).

33.4 Estimated Information

All values provided for mean economic life and standard deviations are Estimated Information. Appendix E, section 1.6 (b) of the CA RIN states that Energex may provide Estimated Information for these variables on an ongoing basis.

33.4.1 Justification for Estimated Information

Distribution asset populations are rarely homogeneous. Whilst asset classes comprise of assets with similar functionality, the specifications and treatment of the assets change over time. The outcome of this situation is that even where historic information exists, the assumptions and treatment of that data can have a material impact on the forecast economic life.

33.4.2 Basis for Estimated Information

In all cases Energex based its Estimated Information on data driven process to the extent possible (as detailed in the approach) followed by peer review of the values.

33.5 Explanatory notes

Where Energex does not own assets that meet the category an economic life cells were left blank.

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**
- **AFLC**

All data provided 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)

Requirements (instructions and definitions)	Consistency with requirements
In instances where Energex considers that both the prescribed asset 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.	Demonstrated in section 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 SCADA Base and project documentation SCADA Base
Local Network Wiring Assets	MCCS
Communications Network Assets • Microwave links • Distribution Systems SCADA (DSS) Head Ends • DSS Radios • Multiplex and MPLS	CBMD ROSS ROSS Project Documentation, CNMS and DB2MGR
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

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 (including MPLS nodes)
MASTER STATION ASSETS	Master Station Assets
	Comms Towers and Poles

Asset Group	Category
COMMUNICATIONS SITE INFRASTRUCTURE	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. 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. Note Energex identified that the previous process of smearing units with unknown commissioning dates could be improved by looking at other dates that are available in the database. This improvement was instigated with the extracts that were performed.

- 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 the SCADA Base application that detailed the commissioning date of each IED. The data was extracted into an Excel spreadsheet and analysed to produce the age profile data.

The total number of IED assets installed in each year was determined by summing the number individual IEDs installed during the year.

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 2015).
- 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 2015 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 data was input into a separate Excel spreadsheet and the total volume MPLS assets installed in each year were determined by summing the number individual assets installed during the year.

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. A commissioning date was estimated by the support group based on commissioning of recent projects.

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 in 2014/15 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. Note an issue was noted and corrected with the spread sheet that produced previous years age profile in that it was not correctly smearing cables with no installation dates into the age profile, this accounts for the increase in total cabling

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 in the excel spreadsheet to determine the per financial year number of units installed.

34.4 Estimated Information

Estimated Information was provided for the following asset categories:

- Field Devices

- Local Network Wiring Assets
- Communications Network Assets
- Master Station Assets
- Communications Site Infrastructure
- Communications linear Assets
- AFLC

34.4.1 Justification for Estimated Information

- Energex does not have historical data for various sub categories of the asset categories and has used various techniques to estimate these. As such Estimated Information is provided for the volume of installed assets by year.

34.4.2 Basis for Estimated Information

- Field Devices - A significant number of protection relays do not have an installation date and these were apportioned based on the population of the installations with dates.
- Local Network Wiring Assets - Energex's systems do not specifically record the date that each multicore cable was installed.
- 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.
- Master Station Assets - The volume of installed master station assets for each year prior to 2012-13 was based on an assumption that each asset was commissioned three years prior to the manufacturer's warranty expiry date.
- Communications Site Infrastructure - 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 the units were installed starting around 1990. With no other data that could be used to approximate per year installation a flat figure was chosen (10 per year).
- Communications Linear Assets – A significant proportion of fibre and copper pilot cables do not have installation dates and these were apportioned based on the population of the installations with dates.
- AFLC – A review of the data showed significant differences from recent samples, and as such is recorded as estimated data.

- The detailed methodology for these asset categories can be found in the methodology section above.

34.5 Explanatory notes

Not applicable.

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.
- The Bureau of Meteorology (BOM) Amberley weather station was used to extract temperature data for the calculation of weather adjusted data.
- 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 01/06 – 31/08.
- The duration of the summer period is usually December, January and February. However, when a seasonal peak falls outside the defined summer period (as the 5th of March did this year), the seasonal data is extended to include the peak.
- Refer to BoP 5.4.1 Maximum Demand and Utilisation Spatial 36.3.1 Assumptions for an explanation of summer and winter peaks.
- The temperature threshold is 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 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.

- The weather data sourced from the Bureau of Meteorology was based solely on the Amberley weather station.

35.3.2 Approach

Energex applied the following approach to obtain the required information:

- The Energex 2015 forecast year covers summer 2014/15 and winter 2014.
- 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.
- 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 for daily maximum MW demand incorporating maximum & minimum temperatures as well as variables for price, economic & demographic drivers, year, 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.

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. b) 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. c) 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	Demonstrated in section 36.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
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 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. b) 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. c) 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	Demonstrated in section 36.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
point. In this example, Energex would specify the 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

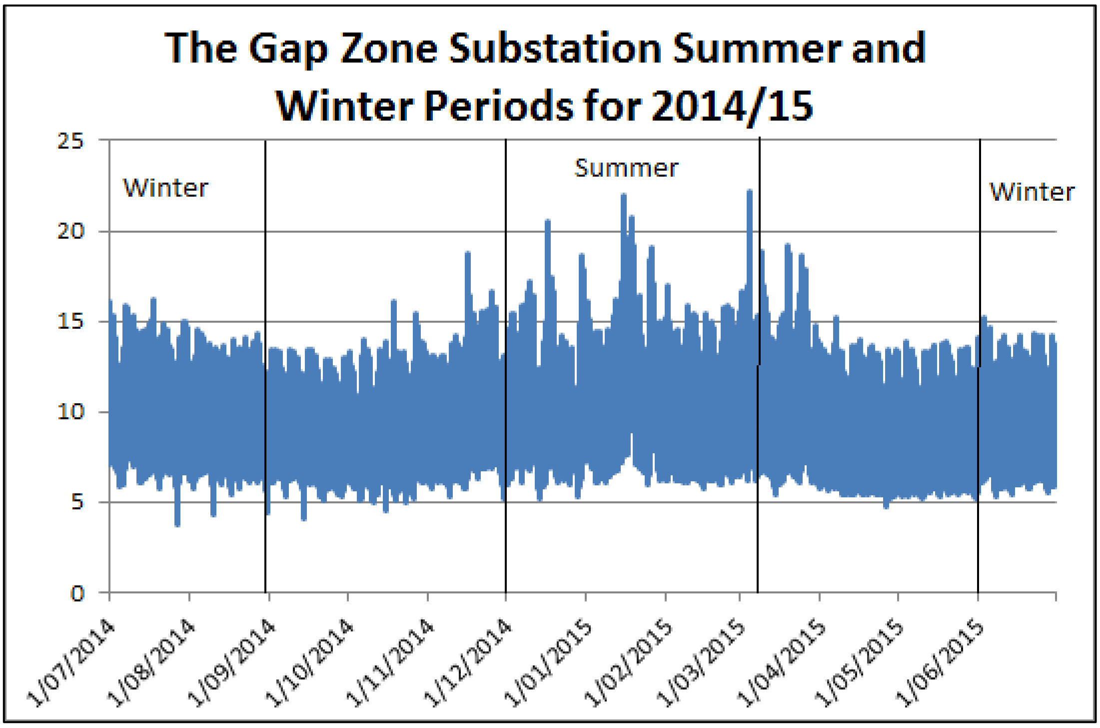
Variable	Source
Weather Corrected maximum demand 10% POE (MW)	SIFT / SCADA / BOM
Weather Corrected maximum demand 10% POE (MVA)	SIFT / SCADA / BOM
Weather Corrected maximum demand 50% POE (MW)	SIFT / SCADA / BOM
Weather Corrected maximum demand 50% POE (MVA)	SIFT / SCADA / BOM

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 the 5 March did this year), 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 14/15 year. It demonstrates that the loads peaked in March-15 (which was within the extended summer period), and hit winter seasonal peak late Jul-14 (within the defined winter period). There were no peaks above the seasonal peaks outside those two periods in the 14/15 year. Therefore, they are consistent with what AER requires.



Graph 1 - Half Hourly MW Load in the Gap Zone Substation in 14/15 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 time of the raw adjusted maximum demand. 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 2015 are based on the greater of the historical maximum demand for the summer of 2014/15, and the historical maximum demand for the winter of 2014.

- 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

37. 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 2014 to 30 June 2015)**

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.	For the regulatory year asset customers by category are calculated daily using a running average of the previous 30 days. This method yields comparable results to the AER mandated method over the reporting year.
The MED status of each sustained event must be identified in table 6.3.1	The MED status for each day is included against all events. The AER mandated 2.5 Beta method has been used in the determination MED's for current year.

Requirements (instructions and definitions)	Consistency with requirements
In completing table 6.3.1, Energex must select a reason from the list provided for in column G. For Initial Regulatory Years, and the 2014 Regulatory Year, Energex may, but is not required to, select a detailed reason from the list provided for in column G (marked with orange cells). For the 2014/2015 Regulatory Year and thereafter, Energex must select a detailed reason for each interruption.	Energex has complied with the Reason and Detail Reason table of 6.3 Sustained Interruptions. As depicted in this table reason of Weather, exclusions 2 thru 7, overloads and planned events will have no detail reason allocated.

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	NFM/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 only available cause code of EN-AB defined in reporting systems as “Animals”. This one cause is the only contributor to the AER Reason and detail reason of Animal and Animal impact respectively. Cause definition has been improved from the commencement of Financial Year 2016 and will facilitate reporting against the AER mandated reason and detail reason in subsequent RIN submissions.

- Unplanned sustained transformer outages with a valid outage report number but no valid feeder or category are excluded from the submitted data. The impact of these exclusions is not material:
  - Customers interrupted (CI) of 3,978 and customer minutes interrupted (CMI) of 511,114 represent less than 0.2% of the respective totals.
- There are 59 outages that have no cause code assigned and are therefore allocated the “No Cause Reported” attribute GN-NR.
- There are 765 feeder identifiers that are listed as unknown. This is due to some transformer interruptions not aligning with a valid feeder in outage data. All SAIDI and SAIFI associated with these instances still contributed to the end of year category results.

37.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Queried EPM to retrieve all sustained (>1 minute) outages by feeder, category and cause.
2) 21,281 outage records were queried and Reason and Detail Reason fields matched utilising Energex cause code to AER reason fields.
3) Excluded from this list of outages were those with no Category or Feeder. This comprised 265 records with CI of 3,978 and CMI of 511,114 representing less than 0.2% of the respective totals.
4) 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.
5) 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 ($) 2015
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 - POW Material Management	-6,705,482.1
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	-11,719,366.7
Total balancing item per above	**-18,424,848.8**

Table 2.1.2 - Standard control services opex by category

Balancing item is made up of:	Actual ($) 2015
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 - POW Material Management	-510,624.8
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	-6,345,754.8
Non-network costs - included in Template 2.6 Non-network as opex and Template 2.10 Overheads	-186,191,097.9
Metering opex - captured in Template 4.1 Metering and certain items (Meter Test and Schedulled Meter Reads) also captured in 2.10 Overheads as Network Overheads Customer Service	-11,628,071.3
Total balancing item per above	**-204,675,548.7**

Table 2.1.3 - Alternative control services capex

Balancing item is made up of:	Actual ($) 2015
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 - POW Material Management	-193,492.1
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	-196,553.4
Metering Capex reported in 4.2 Metering and 4.3 Fee Based Services	-12,795.3
Large Customer Connections reported in 2.5 Connections and 4.4 Quoted Services	-10,516,307.7
Total balancing item per above	**-10,919,148.5**

Table 2.1.4 - Alternative control services opex

Balancing item is made up of:	Actual ($) 2015
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 - POW Material Management	-190,452.7
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	-884,515.7
Metering opex - captured in Template 4.1 Metering and certain items (Meter Investigation and Special Meter Reads) also captured in 4.3 Fee-Based Services	-429,669.6
Total balancing item per above	**-1,504,638.0**

Appendix 2 – Reconciling Items

RECONCILIATION FROM CA RIN SUMMARY NUMBERS TO REGULATORY ACCOUNTING NUMBERS TO AUDITED STATUTORY ACCOUNTS			
	2015		
	CAPEX	OPEX	TOTAL
	$	$	$
Template 2.1 Summary Numbers			
SCS	703,119,117.8	597,394,826.4	1,300,513,944.2
ACS	23,355,478.1	47,946,151.9	71,301,630.0
TOTAL from Template 2.1	726,474,596.0	645,340,978.2	1,371,815,574.2
Adjusted for:			
• Augmentation expenditure not included in Template 2.3 Augex as there was no basis on which to allocate expenditure to categories, but is included in the regulatory accounting numbers	(1,805,171.9)	-	(1,805,171.9)
• Relocation of assets excluded from Templates 2.3 Augex & 2.5 Connections in accordance with the definition of “connections expenditure” but included in the regulatory accounting numbers	7,569,104.3	-	7,569,104.3
• Gifted assets excluded from Templates 2.5 Connections but included in the regulatory accounting numbers	39,532,823.2	-	39,532,823.2
• Asset replacements excluded from Template 2.8 Maintenance in accordance with the definition of "non-routine maintenance" that are included in the regulatory accounting numbers	-	1,215,598.0	1,215,598.0
• Gifted assets excluded from Templates 4.1 Public Lighting but included in the regulatory accounting numbers	5,904,925.2	-	5,904,925.2
• Asset reconfiguration excluded from Template 4.1 Public Lighting as it doesn't meet the definition of "Public Lighting Services" that are included in the regulatory accounting numbers	259,031.9	-	259,031.9
• Adjustments made for the regulatory accounting numbers that don’t appear in the source information for the relevant regulatory templates	2,017,602.9	(14,472.2)	2,003,130.7
Regulatory Accounting Statements	779,952,911.6	646,542,104.0	1,426,495,015.6
Check - reg accounts calc (higher)/lower than actual reg accounts	*0.0*	*(0.0)*	-
Adjusted for:			
• TUOS	-	387,724,992.5	387,724,992.5
• Finance costs	-	321,431,045.0	321,431,045.0
• Depreciation, amortisation & impairment	-	444,058,022.0	444,058,022.0
• Non-regulated services	43,259,361.9	42,249,470.8	85,508,832.7
Audited Statutory Accounts - Consolidated	823,212,273.5	1,842,005,634.2	2,665,217,907.7

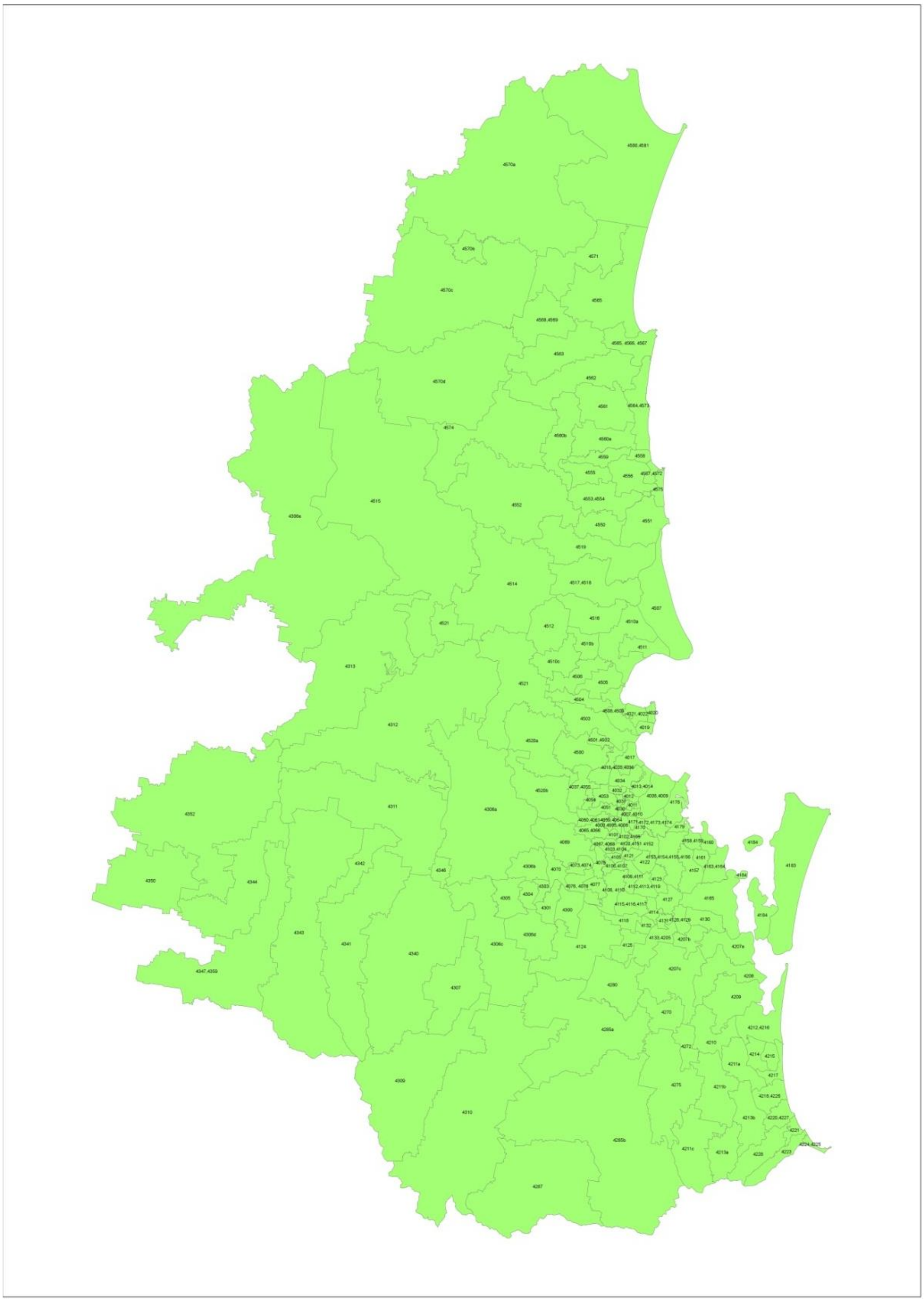
Appendix 3 – Mapping Table

Mapping Table

Reset RIN Categories vs Annual Performance RIN Categories (Capex by Reason)

Service Classification	Reset RIN Categories	Annual Performance RIN (Capex by Reason)
System		
Standard Control	Augmentation	Corporate Initiated Demand
Standard Control	Augmentation	Other
Standard Control	Augmentation	Reliability & Quality Improvements
Standard Control	Connections and customer initiated	Customer Initiated Demand
Standard Control	Replacement	Asset Replacement
Standard Control	Replacement	Other
Alternative Control	Fee based services	Customer Initiated Demand
Alternative Control	Quoted services	Customer Initiated Demand
Alternative Control	Street lighting	Customer Initiated Demand
Non System excluding Control Centre - SCADA	Non-network	Other

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, training, network billing and customer service & call centre.

In addition to the above, Network Overhead includes:

- Meter reading;
- Advertising/marketing;
- Guaranteed Service Level (GSL) payments;
- National Energy Customer Framework (NECF)-related expenses;
- 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 forecasting demand and energy to produce the capital development program for the network as well as the provision of 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; and the Service Target Performance Incentive Scheme (STPIS).

- 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

Meter Reading, Network Billing and Network Monitoring - 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 current 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 supports confidence to management and the board.
  - 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, 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 advising activities (e.g. GST, Fringe Benefit Tax, Payroll Tax, and Income Tax).
  - CFO Management Office - provides leadership and management to Energex to deliver balanced commercial outcomes to the business for initiatives that will assist Energex to deliver on its future vision.
  - 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
  - RedEquip - 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.

Please refer to spreadsheet “Appendix 7 - Network Information – Peak MVA Differing”