Energex

Category Analysis RIN Basis of Preparation 2. Expenditure

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energex

positive energy

Version control

Version	Date	Description
1.0	20/05/2014	Version provided to KPMG
2.0	30/05/2014	Final version submitted to AER

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.

Group Manager
Regulation and Pricing
Energex
GPO Box 1461
BRISBANE QLD 4001

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Template 2 – Expenditure

1 BoP 2.1-1 – Expenditure Summary & Reconciliation

The AER requires Energex to provide the following categories relating to table - 2.1.1 Standard control services capex for 2009 to 2013:

- Replacement expenditure
- Connections
- Augmentation expenditure
- Metering
- Public Lighting
- 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 table - 2.1.2 Standard control services opex by category for 2009 to 2013:

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

The AER requires Energex to provide the following categories relating to table - 2.1.3 Alternative control services capex for 2009 to 2013:

- Connections
- Metering
- Public lighting
- Fee and quoted
- Balancing item
- TOTAL CAPEX

The AER requires Energex to provide the following categories relating to table - 2.1.4 Alternative control services opex for 2009 to 2013:

- Connections

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

The AER requires Energex to provide the following categories relating to table - 2.1.5 Dual function assets capex for 2009 to 2013:

- **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 table 2.1.6 - Dual function assets opex by category for 2009 to 2013:

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

These categories are a part of worksheet "2.1 Expenditure Summary".

Refer to the Basis of Preparation for each individual template for the components that are Actual and Estimated.

All balancing and reconciling items are Estimated information.

1.1 Consistency with CA RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

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 report these amounts in the corresponding rows	Energex does not have dual function assets therefore no values

in tables 2.1.1 to 2.1.6.	are reported in tables 2.1.5 and 2.1.6. These tables are not referred to hereafter. Energex has calculated the expenditure for each capex and opex category reported in CA RIN templates 2.2 to 2.10 and 4.1 to 4.4 (relevant regulatory templates) and summarised these amounts in the corresponding rows in tables 2.1.1 to 2.1.4 where applicable (summary numbers). Summary numbers that aren't available directly from the relevant regulatory templates have been sourced from the supporting workpapers (eg: Public Lighting for table 2.1.1 SCS capex, table 2.1.2 SCS opex, table 2.1.3 ACS capex and table 2.1.4 ACS opex). In these instances, the total for the relevant summary numbers in template 2.1 balance to the relevant regulatory template.
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 the capex and opex for each service classification in CA RIN 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.	Energex has reported amounts that reconcile total capex and opex with the sum of the capex and opex line items in the "balancing item" row in each table in CA RIN template 2.1 so that the sum of each of the capex and opex line items in each of the tables in CA RIN template 2.1 minus the balancing item equals the total capex or opex line item in these tables. The balancing item only includes

	the amount of capex and opex where these expenditures have been reported more than once within the relevant regulatory templates. All capex is reported on an "as incurred" basis so there are no balancing items for this component.
Energex must provide an excel spread sheet that contains the calculation of balancing items reported in *Regulatory Template* 2.1. At a minimum, this spread sheet must: (a) for each instance where an expenditure item is reported more than once (i.e. double counted), identify: (i) where that instance is reflected in expenditure included in the *Regulatory Templates* (ii) the value of that expenditure in each *Regulatory Template* (b) identify each instance where the Notice requires Energex to report *capex* not on an "as-incurred" basis in Regulatory Templates 2.2 to 2.10 and, for the relevant expenditure item, list its corresponding value when expressed on an "as incurred" basis.	Energex has provided the calculation of balancing items reported in CA RIN template 2.1 as Appendix 2 and as a separate excel spread sheet. Where the expenditure item is reported more than once (i.e. double counted) the spreadsheet identifies: (a) where that instance is reflected in the relevant regulatory templates; and (b) the value of that expenditure in the relevant regulatory template. All capex is reported on an "as incurred" basis so there are 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*.	Reconciliations between the Regulatory Accounting Statements and Audited Statutory Accounts for Income Statement and Balance Sheet items are included in each year's Regulatory Accounting Statements. Energex has provided a reconciliation for total capex and opex per template 2.1, based on the relevant year's regulatory accounting numbers and includes any differences between these amounts and the summary numbers (reconciling items). Energex has provided a separate reconciliation between the audited

	statutory accounts and the regulatory accounting statements for total capex and total opex (statutory to regulatory reconciliation).

1.2 Sources

Summary numbers in template 2.1 were sourced from the relevant regulatory templates. Details of specific sources can be found in the relevant Basis of Preparation.

Balancing items in 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 workpapers (regulatory accounting numbers), combined with the detailed workings for each relevant regulatory template.

The statutory to regulatory reconciliation is provided in Appendix 3 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.

1.3 Methodology

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 the relevant years. Summary numbers 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.

The methodology for calculating balancing and reconciling items are detailed below in section 1.1.3.2.

Energex has added rows to tables 2.1.1 SCS capex and 2.1.2 SCS opex for the following items, which is consistent with item 132 of the Issues Register:

- Public Lighting – which was classified as SCS for 2009 and 2010
- Metering – which remains as SCS through to the end of this regulatory control period

1.3.1 Assumptions

All general overhead for non-system capex in 2009 and 2010 is assumed to relate to buildings only.

1.3.2 Approach

Balancing items

Balancing items have been calculated for amounts that appear more than once in the summary numbers, as detailed below. The calculations are detailed in Appendix 2.

- Fleet oncosts (2011 to 2013) – 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 (2011 to 2013) – 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 (all years) – captured in:
  - Template 2.6 Non-network as Buildings & Property opex and
  - Template 2.10 Overhead as Corporate Overhead – Property
- IT & Communications opex (all years) – captured in:
  - Template 2.6 Non-network IT & Communications opex and
  - Template 2.10 Overhead as Corporate Overhead – IT and Communications
- Public Lighting (2009 & 2010) – captured in Template 4.1 Public Lighting and the opex component in Template 2.8 Maintenance as Non-Routine Public Lighting.

  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 Public Lighting for more information).
- Metering (all years) – the various line items within Template 4.2 Metering are duplicated as follows:
  - Meter Test – also captured in Template 2.10 Overheads as Network Overheads – Customer Service

- Meter Investigation – also captured in Template 4.3 Fee-Based Services as a Meter Investigation (2009 & 2010) or Meter Test and Meter Inspection (2011 – 2013)
- 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 Specials Reads (2009 & 2010) or Off-cycle Meter Reads (2011 – 2013)
- Meter Maintenance – also captured in Template 2.10 Overheads as Network Overheads – Customer Service

Reconciling items

Where the summary numbers do not equal the regulatory accounting numbers, differences are detailed in the reconciliation included in Appendix 3. 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 don't 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
  - Overhead adjustment for 2009 & 2010 as explained below in section 1.1.4.2
- Network Overheads and Corporate Overheads for ACS, which are not included in Template 2.1 but are included in the regulatory accounting numbers

Energex's approach to obtaining the regulatory accounting numbers is detailed in the following tables:

<table>
<tr><th colspan="6">Table 2.1.1 - Standard control services capex</th></tr>
<tr><th rowspan="2"></th><th colspan="5">Actual ($000s nominal)</th></tr>
<tr><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th></tr>
<tr><td>Replacement expenditure</td><td colspan="5">As per the AER CA RIN requirements (page 53, CA explanatory statements), repex includes Control Centre - SCADA which was reported in non-system assets in the annual regulatory accounts. For 2009 and 2010, total amounts for Control Centre - SCADA were included in repex as it is assumed that there were no overheads for Control Centre - SCADA (refer section 1.1.3.1 above).</td></tr>
<tr><td>Replacement expenditure</td><td colspan="2">Includes Public Street Lighting, which was classified as SCS for these years.</td><td rowspan="3">Based on supporting working to the annual regulatory accounts plus additional working from the supporting raw data to identify direct costs and overheads by the capex categories required for the AER CA RIN (repex, augex, connections and other).</td><td rowspan="3">Based on supporting working to the annual regulatory accounts plus additional working from the supporting raw data to identify direct costs and overheads by the capex categories required for the AER CA RIN (repex, augex, connections and other).</td><td rowspan="3">Directly from the annual regulatory accounts.</td></tr>
<tr><td>Connections</td><td colspan="2" rowspan="3">To obtain direct costs for repex, augex, connections and non-network, Energex:

1) Requested the reproduction of annual capex reports, disaggregated by direct and overhead costs;

2) Categorised the expenditure according to the CA RIN asset categories (mapping table for the categorisation is in Appendix 1);

3) Summarised the reproduced capex report by reason with the disaggregation between direct costs and overheads. Any differences between the reproduced and original capex reports were allocated to direct costs so as to reconcile to total capex reported in the annual regulatory accounts;

4) Apportioned any accrual entries not included in the reproduced capex report between direct costs and overheads, based on the ratio of overheads to total capex calculated from the reproduced capex report;

5) Adjusted the total capex by reducing it by the amount of capitalised depreciation, as capitalised depreciation was included in the reproduced capex report but needed to be excluded from the figures in the regulatory accounts each year. (Capitalised</td></tr>
<tr><td>Augmentation Expenditure</td></tr>
<tr><td>Non-network</td><td colspan="3">Regulatory accounting numbers. Control Centre - SCADA costs are included in repex and excluded from Non-network as per the AER CA RIN requirements.</td></tr>
</table>

	depreciation represented depreciation on non-system assets which was capitalised into Energex's supply system assets for statutory purposes) 6) Calculated direct costs by asset by reason as follows: = (total capex from reproduced capex report - capitalised depreciation) + proportion of direct costs from the accruals - (overheads from reproduced capex report - capitalised depreciation)	
capitalised network overheads	Portion for each is based on the workings for Template 2.10 Overheads, which reconcile to the total capitalised overheads.	
capitalised corporate overheads		
balancing item	Refer to the separate balancing items sheet	
TOTAL GROSS CAPEX (includes capcons)	Annual regulatory accounts	
capcons	Annual regulatory accounts	

Table 2.1.2 - Standard control services opex by category					
	Actual ($000s nominal)				
	2009	2010	2011	2012	2013
Vegetation management	Directly from the regulatory accounting numbers.				
Maintenance	Includes Inspection, Planned Maintenance and Corrective Repair from the annual regulatory accounts. Also includes Public Street Lighting opex for 2009 and 2010 when it was classified as the equivalent of SCS. Breakdown into Inspection, Planned Maintenance and Corrective Repair is obtained from the regulatory accounting numbers				
Emergency response	Directly from the regulatory accounting numbers				
Non-network	Sum of opex totals from Template 2.6 Non-network expenditure as these figures are not available from the annual regulatory accounts				
network overheads	Portion for each is based on the workings for Template 2.10 Overheads, which reconcile to the total capitalised overheads.				
corporate overheads					

<table>
<tr><td>balancing item</td><td colspan="5">Refer to the separate balancing items sheet</td></tr>
<tr><td>**TOTAL OPEX**</td><td colspan="5">Annual regulatory accounts</td></tr>
</table>

<table>
<tr><th colspan="6">Table 2.1.3 - Alternative control services capex</th></tr>
<tr><th rowspan="2"></th><th colspan="5">Actual ($000s nominal)</th></tr>
<tr><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th></tr>
<tr><td>Connections</td><td colspan="2" rowspan="4">Energex has no Alternative Control Services capex for these years</td><td colspan="3">Energex does not have ACS Connections Assets</td></tr>
<tr><td>Metering</td><td colspan="3">Energex does not have ACS Metering Assets</td></tr>
<tr><td>Public lighting</td><td colspan="2">Sourced from regulatory accounting numbers</td><td rowspan="2">Directly from regulatory accounts</td></tr>
<tr><td>Fee and quoted</td><td colspan="2">Based on additional workings to disaggregate direct costs and overheads for Fee Based and Quoted Services using relevant capex reports. This used the same methodology as used in the 2013 annual regulatory accounts.</td></tr>
<tr><td>balancing item</td><td colspan="5">Refer to the separate balancing items sheet</td></tr>
<tr><td>**TOTAL CAPEX**</td><td colspan="5">Annual regulatory accounts</td></tr>
</table>

<table>
<tr><th colspan="6">Table 2.1.4 - Alternative control services opex</th></tr>
<tr><th rowspan="2"></th><th colspan="5">Actual ($000s nominal)</th></tr>
<tr><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th></tr>
<tr><td>Connections</td><td colspan="5" rowspan="2">Energex has no Alternative Control Services connections and metering services.</td></tr>
<tr><td>Metering</td></tr>
<tr><td>Public lighting</td><td colspan="2">Prior to 2011 Alternative Control Public lighting services formed part of the equivalent Standard Control Services. Consequently Public lighting opex is reported in Table 2.1.2 as SCS for 2009 & 2010 and in Table 2.1.4 as ACS thereafter</td><td colspan="2">Directly from regulatory accounts</td><td>Directly from regulatory accounts</td></tr>
</table>

Fee and quoted	EDS (Excluded Distribution Services) and Infrastructure Projects reported in the 2009 and 2010 annual regulatory accounts have been reported in the CA RIN as Fee-Based and Quoted Services. Refer to the BoP for CA RIN Templates 4.3 and 4.4 for more information. Direct costs were obtained from the regulatory accounting numbers	Regulatory accounting numbers	
balancing item	Refer to the separate balancing items sheet		
TOTAL OPEX	Annual regulatory accounts		

1.4 Estimates

Summary numbers reported in template 2.1 have been treated as Estimates where the relevant regulatory templates are Estimates or a combination of Actual and Estimates.

All numbers reported as balancing or reconciling items are Estimates.

1.4.1 Justification for estimates

Balancing items are regarded as Estimates as they are calculated from the summary numbers, which are a combination of Actuals and Estimates.

All reconciling items are regarded as Estimates as they result from comparing regulatory accounting numbers (which are a combination of Actuals and Estimates) with summary numbers (which are a combination of Actuals and Estimates).

1.4.2 Basis for estimates

Balancing items

The approach for calculating the balancing items is included above in section 1.1.3.2. These numbers are reported as Estimates as the source information is a combination of Actuals and Estimates.

Reconciling items – regulatory accounting numbers

Regulatory accounting numbers regarded as Estimates are those for 2009 and 2010 capex. The supporting workpapers for those years didn't contain the disaggregation for capex direct costs and overheads, as this was not part of the reporting requirements at the time. Adjustments were required to the source data to enable reporting of direct costs only for these years in the CA RIN, therefore making these numbers Estimates.

To obtain the capex direct costs, Energex reproduced the relevant capex reports with disaggregation by direct costs and overheads. Total (constructed asset) capex from the reproduced reports was greater than the original by approximately 0.3% for each year. These variances are due to timing and differences between the project ledger and general ledger. Due to the immateriality of the variances, direct costs from the reproduced reports were reduced by the differences across asset categories (repex, augex, connections and non-system assets) so that the total of direct costs and overheads from the reproduced reports reconcile to the original reports for both years.

Accruals and purchased assets data were apportioned to direct costs and overheads based on the ratio of overheads to total capex from the reproduced capex report.

1.5 Explanatory notes

Explanations for trends in SCS capex (Table 2.1.1) are provided below for the summary numbers. These trends reflect:

- The aging network, evidenced by a doubling of replacement expenditure over the five years;
- Slow economic conditions since the Global Financial Crisis, seen in the declining Connections and customer-driven spend;
- Significant reductions in augmentation expenditure, mostly due to reduced reliability standards and reductions in capex for expected peak demand.

Explanations for trends in SCS Opex (Table 2.1.2) are provided below for the summary numbers:

- The spike in Maintenance costs in 2012 reflects the recognition of a provision for overhead service cable inspections relating to faulty cables;
- Emergency response shows significant increases in 2011 and 2013 due to the major storms and flooding in South-East Queensland
- The significant increase in Network Overheads reflects the inclusion of Solar Photovoltaic Feed-In Tariff Payments.

Extra explanatory notes can be found in the individual Basis of Preparation for respective templates.

1.6 Accounting policies

From the 2011 year, a change in accounting policy came into effect for the statutory accounts to eliminate the capitalisation of non-system asset depreciation.

This change aligned the statutory and regulatory treatment, as the regulatory accounts had previously excluded the capitalised depreciation.

2 BoP 2.2-1 – Repex – Expenditure

In relation to table 2.2.1, the AER requires Energex to provide expenditure values and asset replacement volumes for each year between the period 2008-09 and 2012-13 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**

Note that the basis of preparation for asset failure volumes is provided in a separate chapter.

2.1 Consistency with CA RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

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. Energex must provide corresponding age profile data in regulatory template 5.2 as per its respective instructions.	This requirement has been addressed in the preparing template 2.2.1
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 age profile data in regulatory template 5.2 as per its respective instructions.	This requirement has been addressed in the preparing template 2.2.1

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 provide corresponding age profile data in regulatory template 5.2 as per its respective instructions. 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.	This requirement has been addressed in the preparing template 2.2.1
Energex must ensure that the replacement volumes by asset group is equal to the applicable replacement volume data provided in table 2.2.2.	This requirement has been addressed in the preparing template 2.2.1
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.	This requirement has been addressed in the preparing template 2.2.1
If Energex has provided estimated expenditure data on the basis of historical data that has included works across asset groups Energex must provide the asset age profile data in regulatory template 5.2 against the most elementary asset category. For example, where Energex replaces pole-mounted switchgear in conjunction with a poletop structure it must report the asset age profile data against the relevant switchgear asset category. Energex must provide documentation of instances where backcast unit costs generated have involved allocations of historical records that include expenditure across asset groups.	This requirement has been addressed in the preparing template 2.2.1

Estimated information was provided for all variables.

2.2 Sources

The key data source used to produce estimates for replacement expenditure and asset replacement volumes was EPM. SCADA, network control and protection systems asset replacement data was sourced from a range of project management systems including SIFT, Ellipse, Report Explorer and the Energex intranet.

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
	Transformers	EPM
	Switchgear	EPM
	Public lighting	EPM
	SCADA, network control and protection systems	EPM
Volume of asset replacements	Poles	EPM
	Pole top structures	EPM
	Overhead conductors	EPM
	Underground cables	EPM
	Service lines	EPM
	Transformers	EPM
	Switchgear	EPM

	Variable	Source
	Public lighting	EPM
	SCADA, network control and protection systems	SIFT, Ellipse, Report Explorer, Energex Intranet
List of commissioned projects	Overhead conductors Underground cables Transformers Switchgear	SIFT, Ellipse, Report Explorer, Energex Intranet

2.3 Methodology

2.3.1 Assumptions

At present, Energex does not report replacement expenditure according to the asset categories listed in template 2.2.1 (repex asset categories). In order to satisfy the data requirements in template 2.2.1, Energex was required to develop a methodology of allocating replacement expenditure to the repex asset categories.

For each project that has been analysed as part of template 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 have 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 has been used as a basis for allocating total project expenditure to repex asset categories.

Public lighting projects included in template 4.1 have been excluded from template 2.2.1.

Overhead conductor and underground cable replacement volumes are provided as “km”.

In relation to the asset group - *SCADA, Network Control and Protection Systems* –

- If an indoor circuit breaker was replaced, it was assumed that an intelligent electronic device (IED) was also replaced; and
- If a circuit breaker or ground mounted transformer was replaced the Local Wiring Asset was also replaced.

2.3.2 Approach

The following approach was applied derive these values for replacement expenditure and replacement volumes against the repex asset categories.

2.3.2.1 Step 1 – replacement project data extraction

- A report was run from EPM Business Objects which listed all replacement projects that incurred expenditure between the years 2008-09 and 2012-13 under the following Repex financial activity codes:

Activity Code	Description
C2040	CWT Asset Replacement - Transmission
C2540	Refurbishment Ageing Equipment
C2545	Pole Reinstatement

- This report provided a list of all transactions incurred on replacement projects over the 5 year period, with the exception of replacement volumes relating to the following activities:
  - Pole nailing
  - SCADA, Network Control and Protection Systems

2.3.2.2 Step 2 – analysis of materials expenditure

- Once a list of replacement project transactions was identified, a detailed analysis was undertaken on the materials costs associated with each transaction. The overall purpose of this analysis was to assign each unique material cost to an appropriate repex asset category. By establishing a relationship between material costs and repex asset categories, this 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 between the period 2008-09 and 2012-13 (over 355,000 line items), Energex constrained its analysis to the most meaningful materials transactions, based on material value (approximately 86.8% of materials expenditure was captured for analysis).
  - Allocating each material cost transaction to a repex asset category, based on the stock code associated with the material.

2.3.2.3 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 for each year between the period 2008-09 and 2012-13. 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.
  - Materials expenditure associated with each project, disaggregated by repex asset category, as a percentage of total materials expenditure for the project (that is, a weighted average of materials expenditure).

2.3.2.4 Step 4 – material cost and volume adjustments

A number of manual adjustments were made to account for materials data (either expenditure or volume) not captured in the EPM Business Objects report, prepared in step 1. These adjustments were inputted into an Excel summary sheet, similar in structure to the worksheet prepared under step 3.

Pole nailing

- Pole nailing projects were included in the extract from EMP, 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 EMP physicals report and these volumes were entered as a manual adjustment across the relevant repex asset categories.

Poletop Structures with unknown voltage.

- The material analysis was able to determine the voltage of crossarms for approximately half of the asset replacements. The remaining assets with unknown voltages were allocated to the voltage ranges based on the proportion of assets with known voltages.

SCADA, Network Control and Protection Systems

- Where possible, to enhance efficiencies, Energex plans and undertakes communication asset replacement projects in conjunction with other projects occurring at the same site. These other projects may be refurbishment or augmentation in nature.

- 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 materials costs were mapped to a repex asset category and inputted as a manual adjustment.

Other SCADA and Protections Assets (Fibre cables)

- Fibre optic communications cables were included as an additional asset category. This is due to the cables being linear assets as compared with the communications network assets included above.

- The materials expenditure analysis (step 2) captured the material cost associated with the replacement of copper pilot cables with fibre cables, however, the volume of fibre cables was not quantified. To quantify the fibre cable replacement volumes, Energex undertook a review of specific replacement projects which contained a large component of fibre installation, and used this as a basis for estimating the replacement volumes. These volumes were included as a manual adjustment.

Known commissioned projects

- A number projects commissioned early in the period had materials that were purchased prior to 2008-09 or assets replaced under warranty. These materials were not captured in the EPM Objects report prepared in step 1. This included the following projects.

Project Code	Description	Commissioning Date
C0122079	BLH BEENLEIGH Replace 110kV CB7872	2008-09
C0083637	VAR - On Cond Replacement of Sub Plant	2008-09
C0107253	BMT BLACK MOUNTAIN Replace regulator RG1 (plant no. RG4971)	2008-09
C0148001	LTA LOTA Replace existing TR1 33/11kV 12.5MVA with 25MVA transformer	2010-11

C0208815	VSP Replace Transformer TR1(TR53871) under warranty	2011-12

- The cost and volume of replacement materials associated with these projects were identified by a detailed review of the planning approval reports and engineering specifications. This data was mapped to relevant repex asset categories and included as a manual adjustment.

2.3.2.5 Step 5 – allocation of total project costs to repex asset categories

- To allocate total project expenditure across each repex asset category, the total project expenditure (for each year between the period 2008-09 and 2012-13) was applied to the weighted average materials expenditure associated with the repex asset category1. This provided an estimate of total project cost by repex asset category.
- The total project cost allocated to each repex asset category was then summed across all projects to provide an overall estimate of the expenditure for each repex asset category. These values were then inputted in template 2.2.1.

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

Example:

Consider a project which incurred $40 million of expenditure over the 5 years between 2008-09 and 2012-13, as below:

Year	Expenditure ($m)
2008-09	$5
2009-10	$10
2010-11	$12
2011-12	$9
2012-13	$4
Total project expenditure	***$40***

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

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

summed to $27 million, meaning that $13 million of other costs (labour, contractors and other costs needed to be allocated across repex asset categories.

Repex asset category	Cost of materials ($m)	Percentage of total materials cost
Poles: > 132 kV; WOOD	$5	19%
Underground cables: > 132 kV	$12	44%
Transformers: POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA	$10	37%
Total cost of materials	***$27***	***100%***

The total project cost allocated to a particular repex asset category is calculated as the product of total expenditure for each year and the percentage of total materials cost for that repex asset category. This calculation is outlined in the table below.

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	
2008-09	$0.95 ($5 x 19%)	$2.2 ($5 x 44%)	$1.85 ($5 x 37%)	*$5*
2009-10	$1.9 ($10 x 19%)	$4.4 ($10 x 44%)	$3.7 ($10 x 37%)	*$10*
2010-11	$2.28 ($12 x 19%)	$5.28 ($12 x 44%)	$4.44 ($12 x 37%)	*$12*
2011-12	$1.71 ($9 x 19%)	$3.96 ($9 x 44%)	$3.33 ($9 x 37%)	*$9*
2012-13	$0.76 ($4 x 19%)	$1.76 ($4 x 44%)	$1.48 ($4 x 37%)	*$4*
Total project expenditure by repex asset	***$7.6***	***$17.6***	***$14.8***	***$40***

category				

2.4 Estimates

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

2.4.1 Justification for estimates

As discussed, Energex does not capture costs or quantities in the categories required in tables 2.2.1. As such Energex was required to manually categorise each into the categories required.

SCADA, Network Control and Protection Systems

Energex made the assumption that if an indoor circuit breaker was replaced, an intelligent electronic device (IED) also replaced at the same time. Local Network Wiring assets were also assumed to have been 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.

2.4.2 Basis for estimates

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

The volume of the assets replaced was validated against a list of projects commissioned during the five year period.

2.5 Explanatory notes

General issues

In distribution businesses is very common for projects to span a number of year depending on the complexity of the project, however, the RIN requires expenditure to be reported on an as incurred basis with replacement volumes replaced in the year the final expenditure occurred. This definition leads to a disconnect between replacement expenditure and replacement volumes. For example, if a project spans five years the bulk of the expenditure may occur in the 3rd year based on the purchase of major items, however the replaced assets will not appear in the table until the 5th year.

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

Asset specific issues

For 132kV and 110kV underground cable, there was no capital refurbishment projects commissioned between the periods 1 July 2008 to 30 June 2013. The volumes and expense included in the tables refer to assets installed as part of a larger asset replacement project.

For 132kV, 110kV and 33kV overhead conductors, there was no capital refurbishment projects commissioned between the periods 1 July 2008 to 30 June 2013. The volumes and expense included in the tables refer to assets installed as part of a larger asset replacement project.

Service line replacement programs were not included as they are not categorised as Repex activities, instead they are included as connections activities in RIN table 2.5 Connections.

Public lighting replacement programs were categorised as augmentation in the first 2 years until they were categorised as ACS. The programs included a mixture of replacement and augmentation projects. They have been detailed in RIN table 4.1 public lighting.

Projects with no materials allocated

The allocation of project cost to the Repex asset categories was largely based on analysis of the stock issues to the projects. Where projects did not have any materials issued the expenditure was not included in template 2.2.1. The project expenditure not allocated in template 2.2.1 is included as a balancing item in template 2.1.

The annual expenditure not allocated in the repex model is shown below:

Spend 2009 FY	Spend 2010 FY	Spend 2011 FY	Spend 2012 FY	Spend 2013 FY
6,040,178	2,713,274	4,551,167	8,646,028	14,584,869

This expenditure is covers a total of 2782 replacement projects. This includes 452 cancelled projects and 1921 projects with less than $10,000 accumulated expenditure.

Additional line items

The following additional line items have been added:

- Refurbished < = 1 KV; wood poles

- Refurbished > 1 KV & < = 11 KV; wood poles
- Refurbished > 22 KV & < = 66 KV; wood poles
- Pilot cable assets (SCADA, Network Control and Protection Systems by function)

3 BoP 2.2-2 – Repex – Asset Failures by Category

In relation to table 2.2.1, the AER requires Energex to provide asset failure volumes for each year between the period 2008-09 and 2012-13 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 data was supplied for Public Lighting variables.

Actual recorded information was provided for all other components of submitted data.

3.1 Consistency with CA RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

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	Reporting uses actual recorded failure data filtered to include only causes related to inherent functional failure in accordance with this template.

interference directly, clearly and unambiguously influenced asset performance It also excludes planned interruptions.	

Estimated data was supplied for Public Lighting variables.

Actual recorded information was provided for all other components of submitted data.

3.2 Sources

A number of systems were used to extract asset failure information, as outlined in the table below.

Table 3.2: Information sources

Variable	Source
Poles Failures	In-service Pole Failure Register
Pole Top Structures Failures	(Crossarms) EPM NFM NO
Overhead Conductors Failures	NFM NO
Underground Cables Failures	(110kV/132kV/33kV) Engineering Support Report Register (11kV/LV) NFM NO
Service Lines Failures	SCM SO
Transformers Failures	(110kV/132kV/33kV) Power Transformer Issues Register (Distribution Transformer) NFM NO
Switchgear Failures	(>= 33kV Circuit Breakers) Network Investigation Report (All other types) NFM NO
Public Lighting Failures	Ellipse Report Explorer
SCADA, Network Control and	Ellipse

Protection Systems Failures	

3.3 Methodology

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

3.3.1 Assumptions

For Overhead Conductor, Underground Cable and Service Line Asset failures, the quantity of failure events in the year is reported and not the length (km) of failed asset.

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.

3.3.2 Approach

For each Asset Category, the failure rate data was extracted from the source systems into a central working spreadsheet ('AER_CA_RIN_Asset Failures').

<u>Poles Failures</u>

All in-service pole functional failures are investigated and recorded in a pole failure register by the Network Maintenance & Performance 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 from the pole failure register into a central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in the RIN template table 2.2.1.

<u>Pole Top Structures Failures</u>

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 template 2.2.1. This data was extracted from the EPM report into a central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in the RIN template 2.2.1.

<u>Overhead Conductors Failures</u>

Overhead conductor failure outage data by voltage was extracted into a central working spreadsheet from the Network Outage system from NFM. Failure outage data based on specific cause codes (eg third party, vegetation, weather, underground, substation, wildlife, etc.) was 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 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 spreadsheet). The total asset failures were then collated for each of the relevant sub-categories in the RIN template table 2.2.1.

Underground Cables Failures

All in-service underground 33 kV to 132 kV cable failures are investigated and recorded in an Engineering Support Report Register by the Transmission Department in Service Delivery. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further filtering. This data was extracted into a central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in the RIN template table 2.2.1.

A filtered set of underground conductor failure outage data for 11 kV and LV voltages was extracted into a central working spreadsheet from the Network Outage system from NFM by including data for the specific cause code for underground equipment failure (this excludes for example: third party, vegetation, weather, substation, wildlife). In order to test the accuracy of the data, a sample of the filtered data was analysed in more detail by reading the 'fault' description and 'action taken' description entered by the Network Operator[2]. The error rate in this sample was considered acceptable (11%), and as a result, all of the filtered data was included in the spreadsheet. The total asset failures were then collated for each of the relevant sub-categories in the RIN template table 2.2.1.

Service Lines Failures

A filtered set of service line failure service order data was extracted into a central working spreadsheet from the Service Call Management (SCM) system from NFM using specific cause codes (Faulty Service, Service Fittings broken, Service tail failure, etc.). In order to test the accuracy of the data, a sample of the filtered data was analysed in more detail by reading the 'fault' descriptions and 'action taken' description entered by the Network Operator[3]. The error rate in this sample was considered acceptable (18%), and as a result, all of the filtered data was included in the spreadsheet. The total asset failures were then collated for each of the relevant sub-categories in the RIN template table 2.2.1.

Transformers Failures

[2] The sample comprised 256 items, which represented 65% of the total data set
[3] The sample comprised 500 items, which represented 18% of one year of the total data set

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 Network Maintenance & Performance 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 a central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in the RIN template table 2.2.1.

For 11 kV distribution transformer failures, outages involving in-service failure data are identified in the Network Outage NFM system using key word text searches (it was impractical to analyse every report due to the volume of outage reports over the five year period). All of the filtered failure data was analysed in detail, with an additional column added to the spreadsheet[4] to indicate whether the data was to be included or excluded (any data that was erroneous was not included in the spreadsheet). The total asset failures were then collated into a central working spreadsheet for each of the relevant sub-categories in the RIN template table 2.2.1.

Switchgear Failures

All in-service circuit breakers failures for voltages 33 kV to 132 kV are investigated and recorded in the Network Investigations Report Register by the Network Maintenance & Performance 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 a central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in the RIN template table 2.2.1.

For 11 kV switchgear failures, outages involving in-service failure data are identified in the Network Outage NFM system using key word text searches (it was impractical to analyse every report due to the volume of outage reports over the five year period). All of the filtered failure data was analysed in detail, with an additional column added to the spreadsheet[5] to indicate whether the data was to be included or excluded (any data that was erroneous was not included in the spreadsheet). The total asset failures were then collated into a central working spreadsheet for each of the relevant sub-categories in the RIN template table 2.2.1.

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 Patrols[6]). 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:

[4] The filtered data comprised of 336 items
[5] The filtered data comprised of 184 items
[6] C-10214 covered the period November 2012 to June 2013

- A project work order transaction report was run from Report Explorer ELL00161 against the work orders relevant to the public lighting three public maintenance contracts (that is, 1839810, 1656695, 1656694, 3482304, 3482365 and 3482366).
- This report detailed all expenses against each of the maintenance projects over the five year period.
- 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 for each year (by major road and minor road) was then summed together to provide a proxy for the total annual value for asset 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.

Poles

All in-service pole functional failures are investigated and recorded in a pole failure register by the Network Maintenance & Performance 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 from the pole failure register into a central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in the RIN template table 2.2.1.

<u>SCADA, Network Control and Protection Systems Failures</u>

Failure rates for SCADA, Network Control and Protection Systems assets were obtained by evaluating repair work orders. The first step in the process was to extract 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 each year between 2008-09 and 2012-13.

3.4 Estimates

Data for public lighting has been estimated.

3.4.1 Justification for estimates

Public lighting data was estimated as Energex does not capture the data required in the CA RIN templates.

3.4.2 Basis for estimates

For a description of the methodology for Public Lighting estimates please refer to the methodology section above.

3.5 Explanatory notes

Not applicable

4 BoP 2.2-3 – Repex – Asset Characteristics

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

- **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.

4.1 Consistency with CA RIN Requirements

Table 4.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 4.1: Demonstration of Compliance

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 provide corresponding age profile data in regulatory template 5.2 as per its respective instructions. 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.	This requirement has been addressed in the preparing template 2.2.2
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	This requirement has been addressed in the preparing template 2.2.2

aggregated metrics.	

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.

4.2 Sources

Table 4.2 below 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.
- Only poles with a connected voltage of Low Voltage or higher are included. Therefore streetlight, bollard and cross-street service poles are not included in this value (197,819 of 594,638 poles)
- Only a single feeder type can exist for a pole and will be derived from a feeder associated with the site containing the pole.

Overhead Conductors by: Conductor Length by Feeder Type

- The overhead conductor data does not include assets that are 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 are 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 are 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 are proportioned evenly by 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
  - Underground Cables By: Cable Length By Feeder
- Replacement of Power Transformers will have a material effect on the values reported.

POWER TRANSFORMERS (MVA)	*2008/09*	*2009/10*	*2010/11*	*2011/12*	*2012/13*
TOTAL MVA REPLACED	80	105	0	130	0
TOTAL MVA DISPOSED OF	80	85	0	100	0

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 2013 (30/6/2013) and stored in the schema RIN.

    a. Current feeder categories were used to determine the feeder category as a number of data correction happened post EOF 2013 period which needed to be applied to the data.

    b. LV network inherit the feeder category of the 11kV feeder delivering the supply to the network

    c. Where a site has multiple connections then the pole with in the site will inherit a category based on the following order:

        i. Urban

        ii. Rural

        iii. CBD (High-Density)

2) Extract was run from the RIN schema using the script FeederPoleCategory_2013_v01_00.sql

   a. All sites with a grade code of W have been excluded as W sites are customer owned sites.

   b. Plastic Poles have also been excluded. (24 Poles)

3) Results extracted to Excel file Pole_Feeder_Cat_V01_00.xls

   a. Poles that do not have a feeder allocated (197,819 poles) have been excluded from the reported pole numbers. These poles will be one of the following:

      i. Poles with only decommissioned cables

      ii. Streetlight poles with only street lighting

      iii. Bollard poles

      iv. Cross street service poles

Overhead Conductors by: Conductor Length by Feeder Type

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2013 (30/6/2013) and stored in the schema RIN.

2) Extract was run from the RIN schema using the script FeederCategory_2013_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 has been assumed that where a conductor is connected to only customer assets then that conductor is also customer owned and has been excluded.

Estimated Customer Conductor	*Quantity (km)*
Unknown Category	0.55
Urban	2.85

Estimated Customer Conductor	Quantity (km)
Rural	4.67

b. 110/132kV feeders 711 & 712 as they have been identified as Non-Energex feeders and have been excluded.

Excluded Conductors	Quantity (km)
Unknown Category	44.22

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

4) Within Excel file conductors with an unknown category (637.02km) have been pro-rated into categories CBD, Urban and Rural based on existing ratios.

Conductors Category	Percentage	Quantity (km)
CBD (High-Density)	0.06%	0.36
Rural	61.96%	394.70
Urban	37.98%	241.96

Overhead Conductor By: Conductor Length Material Type

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2013 (30/6/2013) and stored in the schema RIN as tables Conductor_Age_2013 and SEGMENT_CUSTOMER_2013.

2) Extract was run from the RIN schema using the script ConductorType_2013_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 has been assumed that where a conductor is connected to only customer assets then that conductor is also customer owned and has been excluded.

Estimated Customer Conductor	*Quantity (km)*
Aluminium	6.50
Copper	1.57
Steel	0

b. 110/132kV feeders 711 & 712 as they have been identified as Non-Energex feeders and have been excluded.

Excluded Conductors	*Quantity (km)*
Unknown Category	44.22

c. Only overhead conductors were extracted.

d. Where different conductor types exist for a single span then the material with the maximum code value has been used. Generally this will result in the following preference. This assumption affects a non-material portion of conductors (3.85km / 0.01% of conductors)

   i. Steel

   ii. Copper

   iii. Aluminium

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

4) The detailed conductor types were manually rolled up to Aluminium, Steel, Copper or Unknown.

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 (27.27km) have been pro-rated into categories Aluminium, Copper and Steel based on existing ratios.

Conductors Category	*Percentage*	*Quantity (km)*
Aluminium	96.68%	26.37
Copper	0.44%	0.12
Steel	2.88%	0.78

Underground Cables by: Cable Length by Feeder Type

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2013 (30/6/2013) and stored in the schema RIN.

2) Extract was run from the RIN schema using the script FeederCategory_2013_v01_00.sql

   a. Cables are not allocated an ownership value, which generally means that customer owned cables are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these cables captured. In addition assets that 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 cables, it has been assumed that where a cable is connected to only customer assets then that cable is also customer owned and has been excluded.

Estimated Customer Cable	*Quantity (km)*
Unknown Category	0.22
Urban	11.94
Rural	1.86

   b. 110/132kV feeders 711 & 712 as they have been identified as Non-Energex feeders and have been excluded.

Excluded Cables	*Quantity (km)*

Excluded Cables	*Quantity (km)*
Unknown Category	44.22

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

4) Within Excel file cables with an unknown category (128.60km) have been pro-rated into categories CBD, Urban and Rural based on existing ratios.

Cables Category	*Percentage*	*Quantity (km)*
CBD (High-Density)	1.24%	1.60
Rural	28.34%	36.44
Urban	70.42%	90.56

Transformer By: Total MVA

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2008 to 2013 and stored in the schema RIN.

2) Extract was run from the RIN schema using the script Capacity_Transformer_v01_00.sql from the years 2008 to 2013

3) Current Capacity was the summation of all known Rated Outputs for the end of financial year 2013.

Asset Replacements

The following variables have been calculated from values contained in tables 2.2.1 and 2.2.2:

- 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

Asset replacement volumes for the specific asset groups have been calculated by taking the total number of assets replaced from 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 2012/13 is spread between CBD, Urban and Rural short poles based on the volumes currently in service.

Energex was required to add overhead conductor material types. Energex broke down the assets by aluminium, copper and steel conductor.

Transformer By: Total MVA

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2008 to 2013 and stored in the schema RIN.

2) Extract was run from the RIN schema using the script Capacity_Transformer_v01_00.sql from the years 2008 to 2013

3) Information was extracted into individual Excel files: TX_yyyy_v03_00.xls (yyyy = year of extract)

4) Excel files consolidated into excel file TX_Combined_v03_00.xls

5) Within the Excel file the transformers were compared to previous year to determine disposal and replacement MVA quantities.

    a. The previous year asset was compared to the asset installed in the relevant year. 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.

4.4 Estimates

Data for asset replacement volumes for “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” is estimated information due to the judgements that were made during the categorisation of the quantities.

All asset volumes are actual information as the pro-ration does not materially affect the reported numbers.

4.4.1 Justification for estimates

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

4.4.2 Basis for estimates

Replacement volume for the specific asset groups was based on the total volume of asset replaced in table 2.2.1. Table 2.2.1 is 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 – Project Description and Changes

The AER requires Energex to provide the following information relating to Table 2.3.1 – Sub-Transmission Substations, Switching Station and Zone Substations:

- **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 relating to Table 2.3.2 – Sub-Transmission Lines:

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

These variables are part of worksheet 2.3 – Augex.

5.1 Consistency with CA RIN Requirements

Table 5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

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 section 1.1.1.1 for further 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 section 1.1.1.1 for further information.
Energex must not include augmentation information relating to connections in this worksheet.	Details around the development of the project list are covered in the basis of preparation for Augex expenditure figures. Please refer to section 1.1.1.1 for further information.
"For projects with a total cumulative expenditure over the life of the project of greater than or equal to $5 million (nominal):" For 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" For Table 2.3.2 (ii) "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"	Details around the development of the project list are covered in the basis of preparation for Augex expenditure figures. Please refer to section 1.1.1.1 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 subtransmission lines owned and operated by Energex where project close occurred in the years specified in the penultimate row in the table, as indicated.	Details around the development of the project list are covered in the basis of preparation for Augex expenditure figures. Please refer to section 1.1.1.1 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 5.4.2 Basis for estimates Substation Normal Cyclic and Emergency Cyclic Capacity
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.	Please refer to Table 5.5: Substation Projects with Feeder Components
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.	Please refer to Table 5.5: Substation Projects with Feeder Components
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.	Please refer to Table 5.6: Projects which has line or cable removal components
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.	Please refer to section Approach - Project Trigger

Actual information was provided for Substation ID, Substation Type, Line ID, Project ID, Project Type, Project Trigger, Voltage, Substation Ratings* and Route Line Length Added*, whilst estimated information was provided for Substation Ratings and Route Line Length Added where actual information is not available.

*Where actual information is available.

5.2 Sources

As outline in the table below, data was extracted from a number of primary sources

Table 5.2 below sets out the sources from which Energex obtained the required information.

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 applied the following assumptions to obtain the required information:

- 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 at the time where the planning approval report was completed.
- Post-project rating information is based on current plant rating methodologies.

- All ratings are based on summer ratings
- All newly established zone substations would have no pre-project ratings.
- Feeder works within the boundary of the substation is not considered as part of Table 2.3.2 for sub-transmission lines.
- Substation projects consist of feeder works less than 250m route are not considered as part of Table 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 Table 2.3.1. A full list of projects that did not result in a change in capacity is shown in Table 1.5.
- The normal cyclic rating for a substation with an 11kV split bus configuration would be the sum of normal cyclic capacity of the number of transformers connected in that substation.
- If no past information is available, if two or more transformer of large varying sizes is connected in parallel, it is assumed that the smaller transformer are to be operated as hot standby to avoid any load sharing issues that would de-rate the substation.
- Feeders works documented are based on the construction voltage of the feeder
- Feeder re-conductoring works, conductor re-tensioning, pole upgrades, and feeder being re-energise to higher voltage levels is deemed to be classified as sub-transmission upgrade.

5.3.1.1 Approach

All information was sourced based on the AERs requirements. Variables were produced through manual review and cross referencing of sources identified above. The development of each variable is explained below:

Augex Project List

The Augex project list was compiled by the Service delivery Department 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. For the detailed explanation of the development of the project list please refer to basis of preparation 2.3-2. Only projects with total project expenditure greater than $5m were included in the detailed portion of table 2.3.1 and table 2.3.2.

Substation ID

The details of which substation was augmented for each project was taken from either the planning approval report or SIFT. The Substation IDs provided are the three letter substation acronyms of the relevant substations, with a suffix of either “ZS”, “BS” or “SS” to specify if the substation is a Zone Substation, Bulk Supply Substation, or Switching/Regulator Station respectively.

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 was 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 where work was performed on. This however, may not be directly related to the feeder number that appeared on the project title and/or project scope. Note that feeder names can change as subsequent works are carried out.

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

Voltage

The voltage allocated under 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 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.

The list below shows the voltage for feeders where “Other-Specify” is entered in table 2.3.2:

Table 5.3: Voltage for Sub-Transmission Feeders Table 2.3.2

Project ID	Voltage (kV)	Project ID	Voltage (kV)
C0071983	33	C0065337	33
C0016682	33	C0060182	110
C0110005	33	C0075916	33
C0065162	33	C0001714	33
C0074685	33	C0074630	33
C0063527	33	C0016959	33
C0073912	33	C0065233	33
C0019494	110	C0077466	33
C0075936	33	C0017130	33
C0001193	33	C0062102	33
C0078051	33	C0065312	33
C0017014	33	C0100546	33
C0016747	33	C0095006	33

Project Trigger

Project trigger was 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 and it also includes 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 if no work has been done. The list of project with secondary drivers and their descriptions can be seen in the table below.

Table 5.4: Projects with Secondary Drivers

Project ID	Additional Project Triggers
C0065195	Project also addressed fault level and asset condition issues.
C0097859	Project also addressed voltage issue.
C0122016	Project also addressed reactive power issue.
C0068698	Project also addressed fault level issue.
C0065193	Project also had a refurbishment driver.
C0077466	YDS ZS was decommissioned by customer request, as it was located in customer's premises. Remaining network could not support the load without a replacement substation.
C0075936	Project also addressed reliability issue.
C0016747	Project also addressed reliability issue.
C0060182	Project also addressed voltage issue.
C0065233	Project also addressed voltage issue.
C0066526	Project also had a refurbishment driver.
C0115717	Asset had to be removed/relocated due to land resumption by State Government for road upgrades. Project also had a refurbishment driver.
C0062595	Project also had a refurbishment driver.
C0059957	Project also had a refurbishment driver.
C0033135	Project also addressed reliability issue.

C0016940	Project also had a refurbishment driver.
C0016682	Project also had a refurbishment driver.
C0001193	Project also had a refurbishment driver.
C0074630	Project also addressed reliability issue.
C0112332	Project also had a refurbishment driver.

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 Engineering specification was the primary source in determining the project type. Other source of information used where the Engineering Specification is not readily available includes Project Approval Report, Project Scope Statement and Feasibility Study.

Route Line Length Added

Route line length added for a feeder augmentation project was 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’ were searched through the whole document to ensure that no feeder works in the project was 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 was 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 compared against Energex 33 kV SINCAL model, and 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.

If no documentation was available, the information would then be sourced from SIFT where the description of works for the feeder component is then compared 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 table 2.3.2.

The list below shows substation projects which have feeder components entered in table 2.3.2:

Table 5.5: Substation Projects with Feeder Components

Project ID	Augmentation	Project ID	Augmentation
C0016959	New DCCT UG	C0065337	New UG DCCT energised at 11kV
C0016747	New DCCT UG	C0017130	Line Upgrade – Retension/Raising
C0017014	Reconductor OH	C0075916	New OH SCCT
C0060182	Voltage Upgrade	C0077466	New SCCT UG/OH
C0065233	New SCCT OH & Voltage Upgrade	C001714	New SCCT UG/OH
C0062102	Circuit Upgrade	C0065312	New DCCT OH
C0100546	New SCCT OH & Line Upgrade	C0095006	New SCCT OH & Line Upgrade

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 Table 5.6 below.

Table 5.6: Projects which has line or cable removal components

Project Number	Recovered/Abandoned Works
C0016682	Total route length of DCCT UG cable de-energised is approx. 3.3km.
C0110005	Part of existing F394 OH circuit been converted to UG. Total conversion route length is approx. 4.43km.

C0001193	Total route length of DCCT UG cable de-energised is approx. 8.65km.
C0017014	Part of F371 & F484 sections compromising of 7/.104 OH conductors has been replaced with Pluto conductor. Total length of cable re-conductoring works is approx. 10.82.km

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 contained under the ‘Impact of Proposed Works’ section of the Project Approval Report. Where possible, these are cross-checked against the current databases such as ERAT2 and SIFT.

If the values differ between systems, SIFT substation ratings are used as the final result as it is based on current rating methodology and takes into account of the sharing capability between transformers to work out the true substation rating capability.

Below are projects which are substation related projects that do not contribute to the increase in substation capacity.

Table 5.7: Substation Projects with no substation capacity increase

Project Number	Augmentation	Comments
C0115717	Replace 33 kV switchgear and reconfigure 33 kV feeders	No substation capacity increase. Replacement is due to feeder limitations
C0088603	Install 132 kV bus and 2x 50 MVAR 132 kV capacitor banks	No substation capacity increase. Installation is primarily due to voltage limitations on the network.
C0068698	Replace 33 kV switchgear	No substation capacity increase. Replacement is due to fault level limitations on the existing 33 kV switchgear.
C0059957	Replace 33 kV switchgear	This project increases Powerlink’s substation transformer capacity. Energex component is to only replace the 33 kV SWG to suit the upgrade.
C0016740	Install 33 kV bus and	As per assumption, a regulator is treated as a

	30 MVA regulator	transformer without the transformational voltage impact. This project is required to provide voltage support and feeder limitations.
C0069121	Install 132 kV switchgear	No substation capacity increase. Installation of 132 kV switchgear is to address a feeder limitation.

Below are projects where transformers were removed as part of the project scopes:

Table 5.8: Substation projects which have transformers removal components

Project Number	Transformers Removed
C0065195	Removed 2x60MVA 110/33 kV transformers.
C0062685	Removed 2x30MVA 132/11 kV transformers.
C0066526	Removed 3x5/6.25MVA 33/11 kV transformers.
C0060241	Removed 3x5/6.25MVA 33/11 kV transformers.
C0062595	Removed 2x12.5/15MVA 33/11 kV transformers.
C0016659	Removed 2x7.5MVA 33/11 kV transformers.
C0065113	Removed 3x15MVA 33/11 kV transformers.
C0121646	Removed 2x60 MVA 110/33 kV transformers.
C0065156	Removed 2x25MVA 33/11 kV transformers.

5.4 Estimates

5.4.1 Justification for estimates

Energex has at their best endeavour populate the required variable values in table 2.3.1 and table 2.3.2 based on all available historical information.

Due to previous data record issues and upgrades in IT systems, it was inevitable that at times there were no documentation readily available within the Energex systems for a certain number of projects.

Where historical information was not available, estimates of the variable values were provided. The table below shows the project and variables which were estimated in values.

Table 5.9: Projects with estimated variables

Project	Variable Estimated	Augmentation works
C0073912	Overhead Lines – Circuit KM Upgraded	Upgrade existing 33 kV feeder
C0019494	Overhead Lines – Circuit KM Upgraded	Re-energise existing PLQ 275 kV line to 110 kV.
C0017014	Overhead Lines – Circuit KM Upgraded	Reconductor existing 33 kV feeder
C0060182	Overhead Lines – Circuit KM Upgraded	Re-energise existing 33 kV feeder to 110 kV
C0017130	Overhead Lines – Circuit KM Upgraded	Upgrade existing 33 kV feeder
C0060241	Substation Rating Normal Cyclic (MVA) Substation Rating N-1 Emergency (MVA)	Transformer Replacement of 3x 5 MVA units
C0016659	Substation Rating Normal Cyclic (MVA)	Transformer Replacement of 2x 7.5 MVA units

	Substation Rating N-1 Emergency (MVA)	
C0065160	Substation Rating Normal Cyclic (MVA) Substation Rating N-1 Emergency (MVA)	Transformer Replacement of 2x 30 MVA units
C0065193	Substation Rating N-1 Emergency (MVA)	Transformer Replacement of 2x 6 MVA units
C0005517	Substation Rating Normal Cyclic (MVA) Substation Rating N-1 Emergency (MVA)	Transformer Replacement of 2x 25 MVA units
C0065156	Substation Rating Normal Cyclic (MVA) Substation Rating N-1 Emergency (MVA)	Transformer Replacement of 2x 25 MVA units

5.4.2 Basis for estimates

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. If there were no documentation of such, the transformer ratings are calculated based on Energex's current plant rating methodologies as per the Energex Plant Rating Manual. The factors applied to the nameplate of the old transformers are as below.

Table 5.10: Normal Cyclic & Emergency Rating Factors

Load Category	Normal Cyclic (NC) Factor	ONAN Emergency Cyclic (EC) Factor	ONAN Two Hour Emergency Cyclic (2HEC) factor	ONAF,OFDAN & OFDAF Emergency Cyclic (EC) Factor	ONAF,OFDAN & OFDAF Two Hour Emergency Cyclic (2HEC) factor

Domestic	1.2	1.35	1.45	1.25	1.35
Mix Pre-dominantly Domestic (MPD)	1.1	1.2	1.3	1.15	1.25
Mix Pre-dominantly Industrial (MPI)	1.1	1.2	1.3	1.15	1.25
Industrial	1.05	1.2	1.3	1.15	1.25
Continuous	1	1.2	1.2	1.15	1.15

Feeder Length

With the available documentations, it was deemed complex to work out the length of feeder that was upgraded as part of a feeder augmentation project. This is due to the fact that feeder upgrade work consists of varying level of augmentation types to increase its rating capability. Therefore, a feeder upgrade project can consists of a combination of pole replacement, conductor replacement, conductor re-tensioning and 11 kV distribution overbuild.

To reduce the complexity in obtaining this data, the full length of the upgraded feeder is used to populate the “circuit km upgraded” variable. Where more information is available, all best endeavours were done to better reflect on the accuracy of the feeder length upgraded.

5.5 Explanatory notes

Not Applicable

5.6 Accounting policies

Not Applicable

5.7 Nature of the change

Not Applicable

5.8 Impact of the change

Not Applicable

6 BoP 2.3-2 – Augex – Subtransmission

The AER requires Energex to provide the following information relating to 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 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 worksheet 2.3 – Augex.

The following items in table 2.3.1 are estimated:

- **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 variables in table 2.3.2 are estimated with the exception of "Years Incurred"

All remaining variables are actual.

6.1 Consistency with CA RIN Requirements

Table 6.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 6.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
DNSP must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes have been 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.
DNSP must not include information for gifted assets.	No gifted assets have been included.
DNSP must not include augmentation information relating to connections in this worksheet. Augmentations in relation to connections are to be inputted in the connections regulatory template (worksheet 2.5).	No connection expenditure has been included and it has been stated in the connections worksheet.
For projects with a total cumulative expenditure over the life of the project of greater than or equal to $5 million (nominal): For 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 DNSP where project close occurred at any time in the years specified; and For table 2.3.2 ii. 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	Only projects with greater than $5 million nominal expenditure over the life of the project have been reported separately.
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 DNSP where project close occurred in the years specified in the penultimate row in the table, as indicated.	Projects with less than $5 million nominal expenditure over the life of the project have been consolidated into the expenditure figures in the penultimate row of each table.

For table 2.3.2 ii. input the total expenditure for all non material augmentation projects on subtransmission lines owned and operated by DNSP where project close occurred in the years specified in the penultimate row in the table, as indicated.	
Record all expenditure data on a project close basis in real dollars ($2012–13). DNSP must not include data for augmentation works where project close occurs after the years specified but incurs expenditure prior to this date.	All project costs have been stated in real dollars ($2012-13) and were escalated using figures from the ABS.
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.	Installation costs have been reported separately in each table.
(m) 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.

The following items in table 2.3.1 are estimated:

- 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 variables in table 2.3.2 are estimated with the exception of "Years Incurred"

All remaining variables are actual.

6.2 Sources

Table 6.2 below 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 table 2.3.1 and 2.3.2 were calculated by firstly defining the Energex projects that related to subtransmission augex. Each of these projects was then classified as either material or non-material. The transactions against each material project were then analysed to report against the required categories in table 2.3.1 and 2.3.2.

6.3.1 Assumptions

Energex applied the following assumptions 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 subtranmission lines works, for further details please refer to the “Project Description and Changes” Basis of Preparation;
- In table 2.3.1 “other plant items” include subtransmission line materials detailed in table 2.3.2;
- In table 2.3.2 “other plant items” include zone and bulk supply material costs included in table 2.3.1;
- Installation labour in table 2.3.1 includes “cable installation” labour;
- Installation labour has been allocated based on work group;
- Installation volume in table 2.3.1 is the sum of the substation assets installed;
- Installation volume in table 2.3.2 is the sum of the circuit length installed.

- Design and construct contracts have been spread over installation labour, civil works and other direct costs;
- Nominal costs have been escalated based on CPI from the ABS;
- Cost components of project have been escalated based on a single escalation value calculated for each project;
- Number of poles upgraded is dependant on the driver of the project;
- Related party margins are zero.
- For strategic land purchased the project type and project trigger were listed as *Other Specify*.

6.3.2 Approach

Project List Development

A report was run from EPM Business Objects which listed all projects closed within regulatory years 2009 – 2013 under the Augex financial activity codes below.

Activity Code	Description
C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Realiability Sec
C2060	CWT Demand Prim Refurb Sec
C2070	CWT Land & Right of Way
C2075	CWT Easements
C2080	CWT Community Requirements

This report included all Energex projects, not only those related to subtransmission. As such, the project list was filtered to include only those relating to subtransmission by analysing the project descriptions and budget codes.

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) was reported as a separate project in the RIN template. Those projects less that $5 million were labelled as a non-material project to be consolidated into a single substation line item in table 2.3.1 and a single subtransmission line item in table 2.3.2.

Each project was then required to be labelled as either a substation project (for input into table 2.3.1), a subtransmission lines project (for input into table 2.3.2); some projects appear in both tables. Material projects were 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 were allocated to either 2.3.1 or 2.3.2 based on analysis of the project descriptions.

This then gave the list of subtransmission projects to be reported against in tables 2.3.1 and 2.3.2.

Expenditure and Volume Values

The total direct cost for each project reported in tables 2.3.1 and 2.3.2 was then calculated using the yearly costs for each project extracted in the EPM report stated above. These yearly costs were multiplied by an escalation factor to convert the figures to $2012-13. The escalation factors were calculated from the ABS values for CPI based on the eight capital city average and are found below.

Financial Year	Escalation Factor
2002 FY	1.348
2003 FY	1.320
2004 FY	1.277
2005 FY	1.245
2006 FY	1.217
2007 FY	1.182
2008 FY	1.154
2009 FY	1.107
2010 FY	1.080
2011 FY	1.050
2012 FY	1.016

2013 FY	1.000

To calculate the remaining columns in tables 2.3.1 and 2.3.2 a second report was run from EPM which detailed all expenses and quantities against each of the projects. A detailed analysis was then done on each of the project expenses and quantities to determine how they were grouped into the categories required in each table. Each expense was grouped into an intermediate category and then grouped into the categories required in the tables (an intermediate category was required due to the number of transactions that had to be categorised and also to be able to calculate the quantities required in the tables).

An analysis was firstly done on the materials costs against each project. Each materials expense is classified by a Stock Item Group Class (SIGC). The following SIGCs were identified as being both high value and applicable to the material breakup required in tables 2.3.1 and 2.3.2:

- CABLE, ELECTRICAL
- CAPACITORS
- CIRCUIT BREAKERS
- COILS AND TRANSFORMERS
- CONNECTORS, ELECTRICAL
- ELECTRIC HARDWARE
- ELECTRICAL CONTROL EQUIP
- ELECTRICAL TEST
- FIXTURES AND LIGHTING
- FUSES
- INSULATORS
- MISC ELECTRIC POWER
- MISC ELECTRICAL COMPONENT
- PREFAB TOWER STRUCTURES
- RELAYS AND SOLENOIDS
- SWITCHES
- WOOD POLES

Each stock item within these SIGCs was then analysed individually to assign them to one of the following intermediate classifications:

- Cable - Overhead
- Cable - Overhead LV
- Cable - Overhead Transmission
- Cable - Underground Transmission
- Capacitor 15 MVAR
- Capacitor 20 MVAR
- Capacitor 3.6 MVAR
- Capacitor 5.4 MVAR
- Capacitor 62.5 MVAR
- Materials - Other
- Pole
- Pole-SL
- Switchgear
- Transformer - Distribution
- Tx Pwr 120 MVA
- Tx Pwr 15 MVA
- Tx Pwr 25 MVA
- Tx Pwr 30 MVA
- Tx Pwr 60 MVA
- Tx Pwr 8 MVA
- Tx Pwr 80 MVA

Once the materials costs had been classified using the stock item descriptions, the remaining expenses against each project were classified using various information assigned to each expense item. The following table outlines the logic applied to group these expenses into their intermediate expense categories.

<table>
<tr><th>Energex Intermediate Category</th><th>Logic Applied</th></tr>
<tr><td>Civil</td><td>The text ‘civil’ appears in the purchase order or invoice descriptions
The workgroup on the work order ended with ‘CV’ which indicates a civil workgroup
The text ‘civil’ appears in the work order description
The text ‘pit’ appears in the work order description</td></tr>
<tr><td>Energex Labour-Instal</td><td>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</td></tr>
<tr><td>Energex Labour-Non Instal</td><td>All Other Energex Labour costs</td></tr>
<tr><td>IOB</td><td>Account Elements 8570 & 8580</td></tr>
<tr><td>Cable Installation</td><td>Cost Category Type is “Contractor’
Work Order Description contains ‘UG Constr’
The following contractors:
BAYLISS CONSTRUCTIONS PL
DIONA PL
INFRASTRUCTURE CONSTRUCTIONS PL
JEMENA ASSET MANAGEMENT PL
OZCAT CONTRACTING PL
THIESS SERVICES PL</td></tr>
<tr><td>Ctr-D&C</td><td>The texts ‘design’ and ‘construct’’ appear in the purchase order or invoice descriptions</td></tr>
<tr><td>Ctr-Instal</td><td>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,</td></tr>
</table>

	Replace pole, Switching Work Order, Testing/Commissioning, Vegetation Management
Ctr-Non-Instal	• All other Contractor Expenses not classified in any of the above processes
Ctr-Other-DE-WOType	• The work order maintenance type is 'Design' and the cost category type is 'Contractor'
Ctr-Sparq	• Account Element 4940
Easements	• Account Element 3120
Land	• Top Project: Financial Activity Code is C2070 and Account Element is 5405 • Top Project: Financial Activity Code is C2070 and Account Element is 5330 • Top Project: Financial Activity Code is C2070 and a manual review of costs indicates land purchase
Switchgear (DirectMtrls)	• Supplier is Ergon Energy • Supplier is Mitsubishi Electric Australia
Materials-Direct	• Direct Purchase Material costs not classified in any of the above processes
Materials-Stores	• Stock Item Material Stores Issues not classified in any of the above processes
Other	• Cost Category INTERNAL LABOUR - OTHER COSTS • Account Element 4425 • All other residual costs

Once all costs had been categorised into intermediate categories they were then grouped into those required in tables 2.3.1 and 2.3.2. The following table outlines the grouping of intermediate categories for table 2.3.1.

CA RIN Category – Table 2.3.1	Energex Intermediate Categories
Transformers Units Added	Quantity values within: • Tx Pwr 120 MVA • Tx Pwr 15 MVA

	• Tx Pwr 25 MVA • Tx Pwr 30 MVA • Tx Pwr 60 MVA • Tx Pwr 8 MVA • Tx Pwr 80 MVA
Transformers MVA Added	The quantity multiplied by the rating within: • Tx Pwr 120 MVA • Tx Pwr 15 MVA • Tx Pwr 25 MVA • Tx Pwr 30 MVA • Tx Pwr 60 MVA • Tx Pwr 8 MVA • Tx Pwr 80 MVA
Transformers	Expenses within: • Tx Pwr 120 MVA • Tx Pwr 15 MVA • Tx Pwr 25 MVA • Tx Pwr 30 MVA • Tx Pwr 60 MVA • Tx Pwr 8 MVA • Tx Pwr 80 MVA
Switchgear Units Added	Quantity values within: • Switchgear (DirectMtrls)
Switchgear	Expenses within: • Switchgear (DirectMtrls)
Capacitors Units Added	Quantity values within: • Capacitor 15 MVAR • Capacitor 20 MVAR • Capacitor 3.6 MVAR • Capacitor 5.4 MVAR • Capacitor 62.5 MVAR

Capacitors MVAR Added	The quantity multiplied by the rating within: • Capacitor 15 MVAR • Capacitor 20 MVAR • Capacitor 3.6 MVAR • Capacitor 5.4 MVAR • Capacitor 62.5 MVAR
Capacitors	Expenses within: • Capacitor 15 MVAR • Capacitor 20 MVAR • Capacitor 3.6 MVAR • Capacitor 5.4 MVAR • Capacitor 62.5 MVAR
Other Plant Item	Expenses within: • Materials-Direct • Materials-Stores • Cable - Overhead • Cable - Overhead LV • Cable - Overhead Transmission • Cable - Underground Transmission • Pole • Pole-SL • Transformer - Distribution • Materials - Other
Installation Labour - Volume	Sum of substation plant items installed in the project.
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-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C (33%) • 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

The following table outlines the grouping of intermediate categories for table 2.3.2.

CA RIN Category – Table 2.3.2	Energex Intermediate Categories
Poles / Towers Added	Quantity values within:

Poles / Towers Upgraded	• Pole Poles are allocated as either added or upgraded based on the main driver of the project
Poles/Towers Expenditure	Expenses within: • Pole
Overhead Lines Expenditure	Expenses within: • Cable overhead transmission
Underground Cables Expenditure	Expenses within: • Cable underground transmission
Other Plant Item Expenditure	Expenses within: • Switchgear • Materials direct • Materials stores • Materials other • Power Transformers • Capacitor banks • Pole SL
Installation Labour - Volume	Sum of subtransmission line added or upgraded as part of the project
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-Non-Install

	• Ctr-Other-DE-WOType • Ctr-D&C (33%) • Ctr-Sparq • Other • IOB
Total Direct Expenditure	Calculated as per RIN template
Related Party Margins	NA
Total	As per RIN template.
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

6.4 Estimates

The following items in table 2.3.1 are estimated:

- 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 variables in table 2.3.2 are estimated with the exception of "Years Incurred"

All the items above are estimated information due to the judgements that were made during the categorisation of expenses and quantities.

6.4.1 Justification for estimates

Energex does not capture costs or quantities in the categories required in tables 2.3.1 and 2.3.2. As such was required to manually categorise each into the categories required.

6.4.2 Basis for estimates

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

6.5 Explanatory notes

The Total Direct Expenditure column in table 2.3.1. and 2.3.2. are calculated fields within the template, they are also protected. Due to errors in the template some of the cells in total direct expenditure do not have any formulas. As consequence, they are blank and cannot be populated by Energex or any other DNSPs.

7 BoP 2.3-3 – Augex – Distribution

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

- **Hv Feeder Augmentations - Overhead Lines ($000's)**
- **Hv Feeder Augmentations - Underground Cables ($000's)**
- **Hv Feeder Non-Material Projects ($000's)**
- **Lv Feeder Augmentations - Overhead Lines ($000's)**
- **Lv Feeder Augmentations - Underground Cables ($000's)**
- **Lv Feeder Non-Material Projects ($000's)**
- **Distribution Substation Augmentations - Pole Mounted ($000's)**
- **Distribution Substation Augmentations - Ground Mounted ($000's)**
- **Distribution Substation Augmentations - Indoor ($000's)**

These variables are a part of worksheet 2.3 – Augex.

All data is estimated.

7.1 Consistency with CA RIN Requirements

Table 7.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 7.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
DNSP must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes have been 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.
DNSP must not include information for gifted assets.	No gifted assets have been included.
DNSP must not include augmentation information relating to connections in this worksheet. Augmentations in relation to connections are to be inputted in the connections regulatory template (worksheet 2.5).	No connection expenditure has been included and it has been stated in the connections worksheet.
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 have been reported separately. Those with less than $0.5 million were 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).	HV feeder projects with greater than $50,000 nominal expenditure over the life of the project have been reported separately. Those with less than $50,000 were input in the summary row.
Record all expenditure data on an 'as incurred' basis in nominal dollars.	All project costs have been 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 was incurred for the project.	The figures have been reported in line with the last financial year of the project.

Energex must not include expenditure related to land purchases and easements in the 'Total direct expenditure' column. Land purchases and easements expenditure related to augmentation works on all LV feeders owned and operated by Energex must be inputted in table 2.3.6.	Expenditure figures do not include any expenditure for land or easements.

Estimated information was provided for all variables.

7.2 Sources

Table 7.2 below 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 table 2.3.3 were calculated by firstly defining the Energex projects that related to distribution augex. Each of these projects was then classified as either 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 tables 2.3.1 and 2.3.2 as subtransmission projects was added to the figures.

7.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Overhead open wire conductor can be used at any voltage. Overhead conductor with an unspecified voltage was assumed to be HV rather than LV;
- If projects were unable to be assigned to an asset class they were assigned to HV feeders.

7.3.2 Approach

Project List Development

A report was run from EPM Business Objects which listed all projects with transactions within regulatory years 2009 – 2013 under the Augex financial activity codes below.

Activity Code	Description

C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Realiability 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 included all Energex projects, not only those related to HV feeders, LV feeder and distribution transformers. As such, the project list was filtered to include only those relating to relevant assets by analysing the project descriptions and budget codes.

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 Allocation

Each project was then required to be labelled as either a HV feeder, LV feeder or distribution transformer project. This was a complex task as projects rarely include only one asset class. Each project was required to be categorised as different cost thresholds exist for each asset class.

In order to allocate the projects a second report was run from EPM that detailed all expenses and quantities against each of the projects. A detailed analysis was then done on each of the project expenses and quantities to extract overhead cable and underground cable, pole and distribution transformer material booked to the projects.

Each stock item was then analysed individually to assign them to one of the following intermediate classifications:

- Cable - Overhead
- Cable - Overhead LV
- Cable - Overhead Transmission
- Cable - Underground LV
- Cable - Underground HV
- Cable - Underground Transmission
- Materials - Other
- Pole
- Switchgear
- Pole mounted transformer
- Pad mounted transformer
- Ground mounted transformer
- Power transformer

Once the material for each project was known the projects were allocated using an iterative logic approach.

1) The first pass was based on the material expenditure.
2) Where material expenditure was greater than 10% of the project cost and greater than $500 the material was used to separate feeder projects from transformer projects.
3) If a project had greater than 75% transformer materials it was categorised as a transformer project.
4) If a project had greater than 75% feeder materials it was categorised as a feeder project. Of these projects, if the majority of expenditure was LV the project was classified as a LV feeder project, else it was categorised as a HV feeder project.
5) This step covered approximately 50% of the projects.
6) The next step was to categorise the project based on a keyword search of the project title. Some of the keywords used are shown below.

HV Feeders	LV Feeders	Distribution Transformers
11 kV tie 11 up upHV	LV Prot Up LV Aug LV	MDI (Max Demand Indicator) UpTx Tx

7) This step covered approximately an additional 30% of the projects

8) The next step was to use the highest cost element to determine the project.

9) The final step was for asset management engineers to review project descriptions and project documentation to allocate the primary driver of the project.

Once all projects had been categorised as a HV feeder, LV feeder or distribution transformer, cost thresholds were applied to determine which projects would need to be reported as in table 2.3.3 of the RIN. The cost thresholds were $500k for HV feeder projects, $50k for LV feeder projects and $0 for distribution transformer projects.

The projects were then categorised as either overhead or underground for feeders and by transformer type for distribution transformers. The allocation was based on the highest cost element in the project.

The last assessment was whether the augmentation was an upgrade of an existing asset or an addition to the network. This was again based on keywords within the project description coupled with review of project documentation.

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

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

Subtransmission primary projects

The AER requires distribution components of subtransmission projects to also be reported in 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 were allocated to the asset class using the same method detailed above with the addition step of estimating the distribution component of the project.

The distribution component of a subtransmission project was estimated based on the material cost of the distribution assets, e.g. if 5% of the material cost was used for distribution assets 5% of the as incurred expenditure associated with the project will be included as distribution expenditure. This proportioning also applied to the reporting thresholds.

7.4 Estimates

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

7.4.1 Justification for estimates

Energex does not capture costs or quantities in the categories required in tables 2.3.3. As such was required to manually categorise each into the categories required.

7.4.2 Basis for estimates

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

7.5 Explanatory notes

In most projects multiple types of assets will be installed as part of the project, however the reporting by asset class only includes the specific type of asset install as part of the project, e.g. if a HV feeder project includes the installation of a pole mounted transformer, only the HV feeder asset is reported in table 2.3.3.

The assets added or upgraded only include assets that were issued from stores within the 5 year period. Assets issued prior to the period were not included in the analysis. This reduces the volume of assets added or upgraded in 2009.

The volumes of assets added or upgraded in 2013 include projects that were completed in 2013 as well as all open projects that were ongoing in 2013. This increases the volume of assets in 2013 without increasing the expenditure.

The total volume of assets installed as part of all projects is:

Total Asset volume of assets installed by year including transmission primary projects	2009	2010	2011	2012	2013
HV Feeder Augmentations - Overhead Lines (Circuit Line Length Km)	25.71	129.46	49.06	162.99	701.28
HV Feeder Augmentations - Underground Cables (Circuit Line Length Km)	14.47	118.40	35.06	126.84	335.70
LV Feeder Augmentations - Overhead Lines (Circuit Line Length Km)	62.46	221.52	90.25	266.41	1135.14
LV Feeder Augmentations - Underground Cables (Circuit Line Length Km)	7.61	15.27	7.54	34.21	169.89

Distribution Substation Augmentations - Pole Mounted	338	604	89	838	1282
Distribution Substation Augmentations - Ground Mounted	46	247	53	405	473
Distribution Substation Augmentations - Indoor	10	21	10	37	101

As outlined in item 7 in the project allocation above, a review of project documentation was completed for some projects to determine whether a project was an upgrade or addition to the network. The list of projects where a review of documentation was completed are provided in the tables below.

The following table shows the HV feeder augmentation projects where project documentation was reviewed.

Project Number	Description
C0155946	LTN – Improve 11kV Reliability, LTN9
C0127458	RBK – Est Net 11kV Fdr
C0102721	ACR – 11kV Feeder Augmentation

The following table shows the LV feeder augmentation projects where project documentation was reviewed.

Project Number	Description
C0147633	Rectify Overloaded LV circuit Railway St
C0141463	VC Settler Way, Karalee
C0147851	Ins LV Board & Re-configure LV Network
C0110140	*Dungogie Dve, Tallebudgera
C0291751	AUG Voltage complain 15 Ferny Fairway, B

The following table shows the distribution substation augmentation projects where project documentation was reviewed.

Project Number	Description
C0124729	AUG Reconfig SC403 chelsea cr minyama

C0088210	AUG 117 OLYMPIC CCT SOUTHPORT
C0109154	AUG 87 THE SOVEREIGN MILE, PARADISE POIN
C0235343	ST39777 Binna Burra Rd, Beechmont
C0218684	AUG Alma Rd Dakabin
C0110155	AUG 82 Peach Dr, Robina
C0065534	Chambers Flat Rd, Chambers Flat
C0150782	Mildura Dr Helensvale
C0226216	AUG VI SP2355-C Zabel Rd Lockrose
C0321831	Lenneberg St Southport
C0150384	Tsipura Dr Burleigh Heads
C0141682	Volt Imp 68 Wernowskis Road Vernor
C0156437	Brentwood Tce Oxenford
C0330318	Currumburra Rd Ashmore
C0126416	Overload Rectification Miles St Coolanga
C0319613	AUG VI Lansdowne Way Chuwar
C0247681	AUG WEST WYBERBA ST TUGUN
C0115664	AUG V/I 25 Quiberon St Chuwar
C0228638	AUG V/C Hanrahan Rd Coominya
C0128064	AUG Jade Dve, Molendinar
C0303689	Leonard Ave Surfers Paradise
C0126406	Voltage Complaint Golden Four Dve
C0125394	AUG Tamborine-Oxenford Rd, Wongawallan
C0106307	AUG BRYGON CREEK DVE, UPPER COOMERA
C0165448	VI Watsonia Dr Leichhardt
C0128061	AUG Olsen Ave, Ashmore
C0204201	AUG VI 436 Sugarloaf Rd Milford
C0163420	VI 62 Hiddenvale Rd Calvert
C0118936	Gold Coast highway , Mermaid Beach
C0296534	AUG Rectification works Sanctuary Cove
C0123136	AUG V/I George St Somerset Dam

C0325783	AUG VI P13862 Sellars Rd Rosevale
C0130459	Highfield Dve Merrimac
C0147505	VC Forest Hill Fernvale Rd Mt Tarampa
C0290831	Tallebudgera Creek Rd Tallebudgera
C0288485	Bradman Dr Currumbin Valley
C0318691	AUG V/I Ballins Rd Tallegalla
C0119496	*AUG Elizabeth St, Currumbin
C0123613	The Promenade Isle of Capri
C0157426	A2 C25 11KV Hawthorne Rd Linville
C0124565	*Nerang St Nerang (RSL)
C0125392	AUG Pohlman St, Soutport
C0113598	Aug Lake Moogerah Rd Charlwood
C0123143	AUG Government Rd, Labrador
C0125633	AUG Voltage Comp.Malabar Rd.Versdale
C0354794	AUG VI 153Cressbrook Caboonbah Rd Cressb
C0117592	TOWNSON AVE , PALM BEACH
C0115419	AUG Central St, Labrador
C0122046	AUG Ashmore Rd, Benowa
C0120514	AUG V/I 265 Kulgun Rd Kalbar
C0324751	Mudgeeraba Rd Mudgeeraba
C0310066	AUG VI Silverleaves Rd Cressbrook
C0257016	AUG VI SP4096 Higgs Rd Ebenezer
C0147450	VC Bunney Rd Coominya
C0121935	Olsen Ave Labrador
C0326429	AUG VI Morton Vale School Rd Morton Vale
C0134143	AUG VI Robertson Rd Silkstone
C0324261	AUG VI 8616 Warrego Hway Withcott
C0122049	#AUG Bridgeman Dve, Reedy Creek
C0125676	AUGVC Amaroo Rd Thagoona
C0328457	AUG VI SP1987 Gregors Creek Rd Gregors C

C0249475	AUG Rodeo Dve Dayboro
C0149581	V/I KavanaghRdMtTarampa
C0288770	Woodlands Way Parkwood
C0310558	0310559
C0320143	AUG VI SP1697-B Blanchview Rd Blanchvie
C0285985	Ladds Ridge Rd Burleigh Heads
C0312862	AUG Ford Crt, BELMONT
C0286030	Trees Rd Tallebudgera
C0284595	Beechmont Rd Advancetown.
C0304715	AUG VC SP5275 Livingstone Ln Ironbark
C0333380	AUG VI Thagoona Haigslea Rd Haigslea
C0306951	AUG VC SP8282 Malmborg Rd Coominya
C0157097	VC Blanchview Rd, Blanchview
C0287692	AUG MtrPos Mt Stanley Rd Mt Stanley
C0134203	CURRUMBIN CREEK RD , CURRUMBIN VALLEY
C0304747	AUG VC P16862 Old Mt Beppo Rd Mt Beppo
C0149098	Tamborine-Oxenford Rd Wongawallan
C0116664	AUG V/C 163 Ropeley Rd Ropeley
C0120938	AUG (VI Sp4313 Watson dr Ripley)
C0149361	VC 2 Forsyths Rd Limestone Ridges
C0123440	AUG VC 80 Graves Rd Redank Creek
C0150878	VI 788 Middle Rd Purga
C0224659	AUG V/C 548 Karrabin Rosewood Rd Walloon
C0128544	AUG VC 104 Mt Forbes Rd Ebenezer
C0228291	AUG V/C 124 Huth Rd Ironbark

8 BoP 2.3-4 – Augex – Summary Table

The AER requires Energex to provide the following information relating to 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**

These variables are a part of worksheet 2.3 – Augex.

All data is estimated.

8.1 Consistency with CA RIN Requirements

Table 8.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 8.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
DNSP must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes have been reported.
DNSP must not include information for gifted assets.	No gifted assets have been included.
DNSP must not include augmentation information relating to connections in this worksheet. Augmentations in relation to connections are to be inputted in the connections regulatory template (worksheet 2.5).	No connection expenditure has been included and it has been stated in the connections worksheet.
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	Refer to Explanatory Notes

to 2.3.5	
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 purchases and easements’.	‘Land and easements’ rows are mutually exclusive.

Estimated information was provided for all variables.

8.2 Sources

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

Table 8.2: Information sources

Variable	Source
All variables	EPM*

*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 Methodology

All figures for table 2.3.4 were calculated based on the data generated to populate tables 2.3.1 to table 2.3.5. The population of table 2.3.4 was 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 assumptions to obtain the required information:

- Overhead open wire conductor can be used at any voltage. Overhead conductor with an unspecified voltage was assumed to be HV rather than LV;
- If projects were unable to be assigned to an asset class they were assigned to HV feeders.
- Subtransmission projects not reviewed in detail for table 2.3.1 or 2.3.2 were assumed to be either substation or lines projects based on the project description.

- Where projects have a significant combination of Subtransmission and distribution works as incurred expenditure is apportioned based on the relative material costs of Subtransmission assets and distribution assets issued during the period.
- Strategic land and easement purchases have been included as Other Assets in table 2.3.4.

8.3.2 Approach

Project List Development

A report was run from EPM Business Objects which listed all projects with transactions within the regulatory years 2009 – 2013 under the Augex financial activity codes below.

Activity Code	Description
C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Realiability 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 included 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 Allocation

Each project was then required to be labelled as either a HV feeder, LV feeder or distribution transformer project. This was a complex task as projects rarely include only one asset class. Each project was required to be categorised as different cost thresholds exist for each asset class.

This step is detailed in BoP 2.3.3 Augex distribution expenditure for classification of HV feeder, LV feeder and distribution transformer projects.

Sub-transmission projects were detailed in BoP 2.2.1 Augex.

Data Extraction

The following rules were 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 and Final Year Expenditure Incurred = year (i.e. 2009)

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 and Final Year Expenditure Incurred = year (i.e. 2009)

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 and Final Year Expenditure Incurred = year (i.e. 2009)

Other Assets

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

8.4 Estimates

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

8.4.1 Justification for estimates

Energex does not capture costs or quantities in the categories required in tables 2.3.4. As such, Energex was required to manually categorise each into the categories required.

The timing of land and easement expenditure was not captured in the data extract. For consistency, land and easement expenditure has been recorded in the final year of expenditure, similar to asset volumes in table 2.3.3.1. Land and easement expenditure is less than 1 percent of distribution Augex expenditure.

8.4.2 Basis for estimates

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

8.5 Explanatory notes

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

> *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 of Table 2.3.4 reconciles with table 2.3.3. This is expected as they are based on the same data set.

Table 2.3.4 is unable to be reconciled with table 2.3.1 and table 2.3.2. The main causes of difference are:

- Expenditure in table 2.3.1 and 2.3.2 are given in real $ 2012/13.
- Table 2.3.1 only included closed projects, where are table 2.3.4 included open and closed projects.

Although it is possible to compare specific aspects of the two project lists that underlie the tables it is not possible to reconcile the three tables against each other.

9 BoP 2.5-1 – Connections

The AER requires Energex to provide the following information relating to 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**
- **Embedded Generation Connections**
  - **Underground and Overhead Connections**
  - **Distribution Metrics**
  - **Augmentation Metrics**

The AER requires Energex to provide the following information relating to Table 2.5.2 – Connections Cost Metrics (Expenditure and Volume Figures):

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

These variables are a part of worksheet 2.5 – Connections.

9.1 Consistency with CA RIN Requirements

Table 9.1 below 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.	Data provided for connection services reconciles to internal planning models.
Energex is not required to distinguish expenditure for connection services between standard or alternative control services in regulatory template 2.5.	No distinction has been 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 has been 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 have been 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 has been 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 has been 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 have been 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	Connection data has not been duplicated across the templates 2.3 and 2.5.

augmentation data in regulatory templates 2.3 and 2.5.	
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 has been calculated as the sum of the nameplate ratings.
CA RIN – Appendix F: Definitions	All definitions relevant to the connections worksheet have been applied as per the AERs requirements.

Estimate information was provided for all variables.

9.2 Sources

Table 9.2 below 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	Corvu (FIN027), Ellipse, EPM materials report
Augmentation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Commercial/Industrial	
Distribution Substation Metrics	Corvu (FIN027), Ellipse
Augmentation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Subdivision	
Underground and Overhead Connections	Report Explorer ELL00197 - number of lots commissioned
Distribution Substation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Augmentation Metrics	Corvu (FIN027), 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	Corvu (FIN027), Ellipse, EPM materials report
Table 2.5.2 – Cost Metrics	
Residential	
Simple Connection LV	Corvu (FIN027), EPM materials report
Complex Connection LV	Corvu (FIN027), EPM materials report
Complex Connection HV	Corvu (FIN027), EPM materials report
Commercial/Industrial	
Simple Connection LV	Corvu (FIN027), EPM materials report
Complex Connection HV (Customer Connected At LV, Minor HV Works)	Corvu (FIN027), EPM materials report
Complex Connection HV (Customer Connected At LV, Upstream Asset Works)	Corvu (FIN027), EPM materials report
Complex Connection HV (Customer Connected At HV)	Corvu (FIN027), EPM materials report
Complex Connection Sub-Transmission	Corvu (FIN027), EPM materials report

Subdivision	
Complex Connection LV	Corvu (FIN027), EPM materials report
Complex Connection HV (No Upstream Asset Works)	Corvu (FIN027), EPM materials report
Complex Connection HV (With Upstream Asset Works)	Corvu (FIN027), EPM materials report
Embedded Generation	
Simple Connection LV	PEACE, Network Connection Contracts
Complex Connection HV (Small Capacity)	NA
Complex Connection HV (Large Capacity)	NA

9.3 Methodology

All figures covered by this basis of preparation have been developed using the project listings for the relevant financial years. Based on materials booked to projects, project financial activities or project descriptions, these projects have been classified into their respective categories required in tables 2.5.1 and 2.5.2 and the required expenses and quantities have then been reported.

9.3.1 Assumptions

Energex applied the following assumptions to obtain the required information.

- HV has been defined as anything over 1 kV and LV is defined as anything equal to or under 1 kV.

All Residential Variables

- Residential connections are 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” for simple LV works based on volume of 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 template.

- For the volume of connections, it is assumed that each top project represents one connection.

All Commercial/Industrial Variables

- Commercial and Industrial connections are 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” for simple LV works based on volume of 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 template.

- For the volume of connections, it is assumed that each top project represents one connection.

All Subdivision Variables

- Subdivision connections are 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 template.

- For the volume of connections, it is assumed that each top project represents one connection.

- Complex connection HV (upstream works) are 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 was used to distinguish projects.

Embedded Generation

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

9.3.2 Approach

Energex applied the following approach to obtain the required information.

All individual projects undertaken by Energex within each respective year were extracted using the FIN027 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 large amount of the stock code analysis was able to be leveraged from work done in worksheet 2.2 Repex.

The following projects were excluded from the project list to ensure only projects related to connections as specified by the AER were reported on.

Exclusions	Reason
Street lighting (defined by activity codes C2560 and C3560 non gifted)	Street lighting projects were not to be included within the connections worksheet.
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.

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 2013-14. 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 2013-14 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 is assumed to be HV.

Residential

- Distribution Substation Installed Metrics
  - Residential connections with distribution substations were determined to be those projects with an activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’ and had distribution transformers 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 each figure was summated 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 for each respective 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 each respective 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 each respective 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 each respective 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 a funding type of C20 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 each respective 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 a funding type of C20 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 each respective 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 for each respective 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 each respective 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 UG and the number OH. We 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 each respective year.

- Augmentation HV Metrics
  - Subdivision connections with HV Augmentation were determined to be those projects with a project code beginning with 'S' 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 each respective 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 each respective year.

- Cost per Lot
  - To obtain the cost per lot, Energex used the total cost reported in 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 are included in template 4.2 of the RIN.

Table 2.5.2 – Cost Metrics

Once the project list was defined the variables required with table 2.5.2 were calculated using the following logic:

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 each respective 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 for each respective year. The volumes of connections were calculated by using the frequency of projects for each 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 for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.

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 for each respective 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 each respective year. The volumes of connections were calculated by using the frequency of projects for each year.
- Complex Connection HV (Customer Connected At LV, Upstream Asset Works)
  - This classification was determined to be the remainder of projects under the C20 funding type.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each 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 for each respective year. The volumes of connections were calculated by using the frequency of projects for each 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 for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.

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 $250k.

Embedded Generation

- Simple Connection LV
    - No expenditure data was supplied in this category, as per assumptions.
    - 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 Estimates

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 estimates

Data is not captured in the categories required in template 2.5.1 or 2.5.2, therefore costs need to be apportioned.

9.4.2 Basis for estimates

Each cost and quantity has been 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 are based upon the count of projects that were determined to fall in the particular categories required in worksheet 2.5. Where a project was done over multiple years it may be counted more than once, however the effect of this is immaterial. All MVA added and circuit kilometres added metrics are 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 $100m in metering expenditure, this is detailed in template 4.2. Expenditure associated with metering was removed from activity C2570 prior to allocation in template 2.5.

10 BoP 2.5-2 – Connections – UG, OH and Simple Connections

The AER requires Energex to provide the following information relating to Table 2.5.1 – Connections Descriptor Metrics:

- Residential Connections
  - Underground Connections
  - Overhead Connections
  - Mean Days To Connect Residential Customer With LV Single Phase Connection
  - Volume Of GSL Breaches For Residential Customers
  - Volume Of Customer Complaints Relating To Connection Services
  - GSL Payments
- Commercial/Industrial Connections
  - Underground Connections
  - Overhead Connections

The AER requires Energex to provide the following information relating to Table 2.5.2 – Connections Cost Metrics (Expenditure and Volume Figures):

- Residential Connections
  - Simple Connection LV
- Commercial/Industrial Connections
  - Simple Connection LV

These variables are a part of worksheet 2.5 – Connections.

Actual information was provided for:

Table 2.5.1 – Descriptor Metrics

- Mean Days to Connect Residential Customer With LV Single Phase Connection
- Volume of GSL Breaches For Residential Customers
- Volume of Customer Complaints Relating To Connection Services
- GSL Payments

Table 2.5.2 – Cost Metrics

- Residential Simple Connection LV (Volumes only)

Estimated information was provided for:

Table 2.5.1 – Descriptor Metrics

- Residential Underground Connections
- Residential Overhead Connections

- **Commercial/Industrial Underground Connections**
- **Commercial/Industrial Overhead Connections**
- **Commercial/Industrial Simple Connection LV**

10.1 Consistency with CA RIN Requirements

Table 10.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 10.1: 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.	The data provided reconciles to Energex internal planning models.
• Energex is not required to distinguish expenditure for connection services between standard or alternative control services in regulatory template 2.5.	No distinction has been made between SCS and ACS
• Energex must report data for non-contestable, regulated connection services. This includes work performed by third parties on behalf of Energex.	Data has only been provided for regulated connection services.
• 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 data for gifted assets was reported.
• Energex is not required to report data in respect of *GSLs*, where a *GSL* scheme does not exist for the *connection service*.	Not applicable
• CA RIN – Appendix F: Definitions	All definitions relevant to the connections worksheet have been applied as per the AERs requirements.

Actual information was provided for:

Table 2.5.1 – Descriptor Metrics

- Mean Days to Connect Residential Customer With LV Single Phase Connection

- Volume of GSL Breaches For Residential Customers
- Volume of Customer Complaints Relating To Connection Services
- GSL Payments

Table 2.5.2 – Cost Metrics

- Residential Simple Connection LV (Volumes only)
-

Estimated information was provided for:

Table 2.5.1 – Descriptor Metrics

- Residential Underground Connections
- Residential Overhead Connections.
- Commercial/Industrial Underground Connections
- Commercial/Industrial Overhead Connections
- Commercial/Industrial Simple Connection LV

10.2 Sources

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

Table 10.2: Information sources

Variable	Source
Table 2.5.1 – Descriptor Metrics	
Residential	
Underground and Overhead Connections	PEACE (FRC213)
Mean Days To Connect Residential Customer With LV Single Phase Connection	PEACE (FRC213)
Volume Of GSL Breaches For Residential Customers	FROG & Cherwell
Volume Of Customer Complaints Relating To	FROG & Cherwell

Connection Services	
GSL Payments	Guaranteed Service Level Utility System (GUS) & Cherwell
Commercial/Industrial	
Underground and Overhead Connections	PEACE (FRC213)
Table 2.5.2 – Cost Metrics	
Residential	
Simple Connection LV	PEACE (FRC213)
Commercial/Industrial	
Simple Connection LV	PEACE (FRC213)

10.3 Methodology

Data provided for connection volumes in table 2.5.1 and 2.5.2 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 report also includes the completion date and time of the service order.

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.

10.3.1 Assumptions

The following assumptions have been applied in collecting the data:

- The FRC213 report determines the volume of connections details service order jobs based on the date the service order response was sent to the requesting retailer. This may differ to the time 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. This will however only affect service order jobs that fall over two financial years and therefore the effect of this variance is considered immaterial.

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

- Simple low voltage connections have been collated based on customer initiated work requests within the reportable period.

- 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.

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

10.3.1.1 Approach

Energex applied the following approach to obtain the required information.

Table 2.5.1 – Descriptor Metrics

Residential

Underground and Overhead Connections

- The number of Underground and Overhead connections was determined by collating the monthly FRC213 reports for each respective financial year.

- The FRC213 report specifies service orders based on customer classification. This classification was used to extract only those service orders relating to residential connections.

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

- 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.

Mean Days To Connect Residential Customer With LV Single Phase Connection

- The “mean days to connect residential customers with LV single phase connection” for each year was calculated from the FRC213 report. This report specifies the start and finish date of each service request.

- 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 was calculated from the data in the FRC213 report. The earliest work start date is defined as the latest date of either:
  - Business to Business (B2B) Received Date + 1
  - B2B Obligation Start Date

- EWR Received Date + 1
- EWR Ready for Test Date.
- Appointment Date

- The times taken to connect customers in each respective year were then averaged to obtain the data reported in the template.

- This calculation however does not take into account delays in receiving required customer paperwork for solar connections (i.e. solar agreement) which can inflate the average despite Energex still completing the work within the obligated timeframes. This earliest work start date is not updated to reflect the connection agreement process.

Volume Of GSL Breaches For Residential Customers

- Guaranteed Service Level (GSL) data is derived from a report which extracts information from the Guaranteed Service Level Utility System (GUS) for volumes in 2008-09 and 2009-10, and the Cherwell system for volumes from 2010-11 onwards. The report details the type of GSL, the amount paid to a customer and the relevant date the payment was made.

- These reports were collated for each financial year and GSL transactions not categorised as “New Connection” were excluded.

- The frequency of payments per year was then reported as the volume of breaches for residential customers.

Volume Of Customer Complaints Relating To Connection Services

- Complaint data is derived from a feedback report which extracts information from the Feedback Register for Organisational Growth (FROG) system (for volumes in 2008-09 and 2009-10) and the Cherwell system (for volume in 2010-11 onwards) 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 within Customer Contact Group using the systems feedback structure.

- The reports above were collated for each relevant financial year

- Only complaints with the following classifications were included:
  - New connection
  - Existing connection

- Total volumes of complaints relating to connections were then calculated by summing the volume of the above complaint categories for each financial year.

GSL Payments

- Guaranteed Service Level (GSL) data is derived from a report which extracts information from the Guaranteed Service Level Utility System (GUS) for volumes in 2008-09 and 2009-10, and the Cherwell system for volumes from 2010-11 onwards. The report details the type of GSL, the amount paid to a customer and the relevant date the payment was made.

- These reports were collated for each financial year and GSL transactions not categorised as “New Connection” were excluded.

- Total GSL payments were then calculated as the sum of amounts paid to customers in each financial year.

Commercial/Industrial

Underground and Overhead Connections

- The number of Underground and Overhead connections was determined by collating the monthly FRC213 reports for each respective financial year.

- The FRC213 report specifies service orders based on customer classification. This classification was used to extract only those service orders relating to commercial/industrial connections.

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

- 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.

Table 2.5.2 – Cost Metrics

Residential

Simple Connection LV

- The number of simple LV connections for residential customers was determined using the same methodology as the residential underground and overhead connections in table 2.5.1. The figures reported are the aggregation of both underground and overhead residential connections.

Commercial/Industrial

Simple Connection LV

- The number of simple LV connections for commercial/industrial customers was determined using the same methodology as the commercial/industrial underground and overhead connections in table 2.5.1. The figures reported are the aggregation of both underground and overhead commercial/industrial connections.

10.4 Estimates

Energex applied the following estimates to obtain the required information of overhead and underground connection types:

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.

10.4.1 Justification for estimates

When submission of a B2B from a Retailer does not indicate the connection type, the extracts obtained from PEACE CIS will not return any value. It was necessary to estimate required information as it is not possible to obtain the level of detail elsewhere.

10.4.2 Basis for estimates

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.

10.5 Explanatory notes

Energex's service order timeframe performance during 2011/12 year was impacted by a substantial increase in volumes of solar photovoltaic (PV) service order requests. This was driven by changes to the Federal Government's Renewable Energy Certificate (RECs) scheme which, from 30 June 2011, reduced the number of RECs available for solar PVs. This was the main contributor to the increase in Average Days to connect customers during the 2010/11 and 2011/12 periods.

New Connection GSLs paid during the 2008/09 period were impacted by the PEACE system upgrade which took effect in July 2008 in line with the commencement of Full Retail Contestability (FRC). These service orders failed to transition to the PEACE system in order to be completed within the obligated timeframes.

11 BoP 2.6-2 – Non-Network – Fleet, Tools and Equipment

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

- **Motor Vehicles – Opex and Capex**
- **Other Non-Network Expenditure Fleet Tools & Equipment – Opex**
- **Other Fleet - Mobile Generators – Capex**
- **Other Fleet - Trailers – Capex**
- **Other - Tools & Equipment – Capex**

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

- **Motor Vehicles Descriptor Metrics**

These variables are a part of worksheet 2.6 Non-Network

Actual information has been provided for all tables.

11.1 Consistency with CA RIN Requirements

Table 11.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

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.
Table 2.6.1 in the CA RIN **Clause 10.5 of RIN:** In relation to the	Non-Network Expenditure for Opex & Capex 2009-2013 has been broken down into the following Service Sub Categories

Requirements (instructions and definitions)	Consistency with requirements
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.	and Asset Categories: • Motor Vehicles - Network Expenditure Cars - Network Expenditure Light Commercial Vehicles - Network Expenditure LCV - Elevated Work Platforms - Network Expenditure HCV - Elevated Work Platforms - Network Expenditure HCV - Other • Other o Other Fleet - Mobile Generators (Capex only) o Other Fleet – Trailers (Capex only) o Other Fleet o Other - Tools & Equipment
Table 2.6.3 in the CA RIN	Non-Network Expenditure Annual Descriptor Metrics for Capex 2009-2013 has been broken down into the following Non-Network Category and Asset Categories: • Motor Vehicles - Car - Light Commercial Vehicle - Elevated Work Platform (LCV) - Elevated Work Platform (HCV) Heavy Commercial Vehicle (Other)
Appendix F: Definitions of RIN outlines the definitions of: Car Elevated Work Platform (LCV) Elevated Work Platform (HCV) Heavy Commercial Vehicle (HCV) Light Commercial Vehicle (LCV) Non Network Other Expenditure.	Definitions of the following Service Sub Categories and Asset Categories • Motor Vehicles - Network Expenditure Cars o Vehicles having a gross vehicle mass of less than 1.5 tonnes including sedan, hatch, wagon, Utes's 2WD, 4WD & AWD's - Network Expenditure Light Commercial Vehicles o vehicle mass of greater than 1.5 tonnes but not exceeding 4.5 tonnes - Network Expenditure LCV - Elevated Work Platforms o Vehicles with permanently attached elevating work platforms having a gross vehicle mass not exceeding 4.5 tonnes - Network Expenditure HCV - Elevated Work

Requirements (instructions and definitions)	Consistency with requirements
	Platforms o Vehicles with permanently attached elevating work platforms having a gross vehicle mass of greater than 4.5 tonnes - Heavy Commercial Vehicle o Vehicles with having a gross vehicle mass of greater than 4.5 tonnes excluding Elevated Work Platforms • Other - Other Fleet o Mobile Generators o Trailers with ATM from 3.5T to over 10 tonne o Forklifts o Earthmoving Equipment o Mobile Plant Mobile Equipment & Tools

Actual information was provided for all variables where possible, however where information was not available to Energex, actual information was provided by Energex's Fleet Management company SG Fleet Australia. This information was based on invoice payments per motor vehicle category.

11.2 Sources

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

Table 11.2: Information sources

Variable	Source
Non-Network Opex Expenditure Motor Vehicles & Other 2009-13	• Ellipse Financial Reports: - Profit & Loss Reports - Detailed Transaction Reports • Discussions with Department Managers • Operating Expenditure Reports from SG Fleet Australia Pty Limited (our Fleet Managers) to allocated cost per Asset Category
Non-Network Capex Expenditure Motor Vehicles & Other 2009-13	• Ellipse Financial Reports: - Capex Summary Reports - Detailed Transaction Reports • Fleet List including Terminations to cross reference

Variable	Source
	Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) • Previous Annual Capex RIN reports provided by Energex External Reporting team
Non-Network Descriptor Metrics Motor Vehicles 2009-13	• 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

11.3 Methodology

Below is the Approach that was taken to report the Non-Network Motor Vehicle and Other Expenditure into the Categories as outlined in the RIN.

11.3.1 Approach

Energex applied the following approach to obtain the required information for **Non-Network Motor Vehicles & Other** Opex Expenditure for 2009-13:

Obtained Profit and Loss reports for all Departments within Fleet, Tools and Equipment and detailed transaction reports for Generator Services, Plant Workshops, Equipment Testing and Laboratory Services from Commercial Services (Energex finance team).

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.

Obtained annual expenditure reports 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.

In 2012/13 Energex received an accumulated $1.65M fuel tax credit for the period 2010/11 to 2012/13. For 2013/14 an amount of $210k was paid as a carryover from 2012/13 in addition to an expected credit of approximately $600k pa every year from 13/14 onwards.

Specific spend that could be allocated to individual Asset Categories are detailed as follows:

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

- 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. The units at the end of each financial year were used as the method of allocating costs to these two categories.

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

- 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 fleet and tools & equipment using detailed transaction reports based on an analysis of work orders.

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

- Employee Contributions were allocated 100% to Non-Network Operating Expenditure Car. Some employment positions within Energex require the employee to have a car. This car is available for the employee's private use. For this privilege, the employee contributes back to Energex the value of this private use, via salary sacrifice. In an average year 54% of the employees with salary sacrifice vehicles are contributing 100% of the cost of this vehicle, including finance charges and cost of capital.

- In all instances, depreciation has been excluded from the reported opex costs.

- In all instances, only indirect costs have been reported.

Energex applied the following approach to obtain the required information for **Non-Network Motor Vehicles & Other** Capex Expenditure for 2009-13:

Obtained Capital Summary reports and Detailed Capital Transaction Reports for Fleet Tools and Equipment from Commercial Services (Energex finance team). These reports were used to identify the total of the Financial Purchases per annum.

The Detailed Capital Transaction report was used to report the capital purchases, using the unique Fleet Number to identify the Asset Category. Due to the requirement to make progress payments on certain assets due to the length of time that these assets take to build and to mitigate some of the suppliers' financial risk, transactions are recorded over several months. Assets that fall into this category are Crane Borers and Elevated Work Platforms.

Per Clause 10.5 of the RIN, Energex has incurred $1 million or more in capital expenditure for three classes of assets and these have been reported separately. These additional asset classes are Mobile Generators, Trailers and Tools & Equipment. All other Non Network Other Capital Expenditure is reported as Other.

Obtained Complete Fleet list including historical Fleet Terminations (sales). This report was used to cross reference the unique Fleet Number to the Ellipse Reports (for both Unit Additions and Financial Purchase Transactions) to identify the Asset Categories. This report is provided by our Fleet Management Company SG Fleet Australia Pty Limited.

Obtained Annual RIN reports from External Reporting (Energex finance team) to reconcile Fleet, Tools and Equipment Capital Expenditure over the periods.

Energex applied the following approach to obtain the required information for **Non-Network Motor Vehicle Annual Descriptor Metrics** 2009-13:

Annual kilometres:

- Annual kilometres were calculated using the reported kilometres of all active vehicles during the financial year. 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. The vehicles were split into the Asset Categories, 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 our Fleet Management Company SG Fleet Australia Pty Limited. The average calculation was performed by the Non System Program Manager.

Units Purchased:

- Units Purchased were obtained from the Detailed Capital Additions reports for Fleet Assets from Capital Accounting (Energex finance team). This report identifies the Fleet Unit by its unique Fleet Number, and reports the date it was put into service (commissioned by Energex).

- The Additions data was reviewed to ensure only one addition was reported per unique Fleet Number. This involved excluding transactions in subsequent financial periods that related to the original commissioning of the asset ie: accessories purchased separately. Excluded also were transactions relating to Plant rebuilds eg: Crane Borers and Elevated Work Platforms, as these transactions did not create a new asset.

- Obtained Complete Fleet list including historical Fleet Terminations (sales). This report was used to cross reference the unique Fleet Number to the Ellipse Reports (for both Unit Additions and Financial Purchase Transactions) to identify the Asset Categories.

Leased Units:

- Energex does not lease any Motor Vehicles.

Number in Fleet:

- Obtained the Fleet Units at the end of each financial year 2009-2013 from our Fleet Management Company SG Fleet Australia Pty Limited. CA RIN Appendix F: Definitions outlines that the Number in Fleet should be the average of the units across the financial year. As this data is not available per month, the opening and closing balances have been used to average the units across the financial year.

11.4 Estimates

Energex has not used estimated data in preparation of this RIN.

11.5 Explanatory notes

As mentioned in the Approach for Non-Network Motor Vehicles & Other Capex Expenditure for 2009-13 item 2), careful attention has to be given to the use of this information to calculate unit rates per Asset Category.

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. This has occurred throughout the past five financial years, and is very evident when there is expenditure and no physical in that year ie: 2012/13 Network Expenditure HCV – Elevated Work Platforms.

11.6 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice, has not materially changed in nature.

12 BoP 2.6-1 – Non-Network – IT & Communications

The AER requires Energex to provide the following information relating to Non-Network Expenditure and annual descriptor metrics for years 2008/09, 2009/10, 2010/11, 2011/12 and 2012/13:

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

These variables are a part of worksheet 2.6.1 – Non-Network Expenditure and 2.6.2 Annual Descriptor Metrics

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)

12.1 Consistency with CA RIN Requirements

Table 12.1 below 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. 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.

12.2 Sources

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

- The financial data provided in 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 table 2.6.2 has been sourced as follows:
    - Employee numbers – Energex Annual Stakeholder Reports contained on the Energex website.
    - User numbers – from software licencing compliance reports for the period 2008/09 & 2009/10 and for the period 2010/11 to 2012/13 from Microsoft Active Directory reports (these were not prepared prior to 2010/11 FY)
    - Number of devices – the data reported is sourced from reports used for demonstrating compliance to Microsoft for the licensing obligations associated with the Microsoft applications used by these devices. These counts are 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 to manage network user accounts and computer objects. All employees are given a user account within Active Directory. Underpinning the directory service is a database which contains unique identifiers for each object as well as various attributes associate with those objects. Reports are run against this database to determine the number of employees, active computers etc.

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 information as per RIN – Financial System Ellipse

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

Table 12.2: Information sources

Variable	Source
Client Device Expenditure – OPEX ($000’s)	SPARQ information based on invoices issued to Energex
Client Device Expenditure – CAPEX ($000’s)	Accounting Entry Report per

Variable	Source
	Ellipse
Recurrent Expenditure – OPEX ($000s)	Profit and Loss for SPARQ division from EPM for Cost of Sales, Telecommunications, Asset Usage Fee, Finance Fee & SLA
Recurrent Expenditure – CAPEX ($000s)	Capex expenditure per Regulatory accounts less Client Devices per Accounting Entry Report
Non-Recurrent Expenditure – OPEX ($000s)	Profit and Loss MOPEX RC 1025 (2310 for 08/09) account 4940
Non-Recurrent Expenditure – CAPEX ($000s)	Not applicable
Employee numbers	Sourced from annual shareholders reports of Energex
User numbers	Active IT system log in account used in the year
Number of devices	Client devices used as provided IT services

12.3 Methodology

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

The cost information provided in table 2.6.1 is as sourced from the SPARQ Solutions financial system and is 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 are not attributed by Sparq Solutions to specific Energex business operations as this is dealt with internally by Energex using the Energex 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.

ICT data was reconciled by Energex between the two organisations and certain items pertaining to the employee transfers in 2008/09 were required to be adjusted.

12.3.1 Approach

Energex applied the following approach to obtain the required information:

OPEX

SPARQ provided financial data detailing the charges from SPARQ to Energex for the financial years as per the breakdown required in the CA RIN. SPARQ reconciled these charges to invoices and their audited financial statements. for SPARQ from EPM by financial year. Prior to SPARQ being created the ICT services were managed under the Energex CIO. As such, the responsibility centres in the years 2008/09 and 2009/10 were part of the original area of the “Chief Information Officer”. The number of responsibility centres for 2010/11 onwards was then rationalised down to a virtual unit called “SPARQ” with 3 responsibility centres. The following responsibility centres were used for the EPM reports:

- 08/09 – 2310, 2311, 2312, 2313, 2315, 2320, 2330, 2335, 2340, 2350, 2360
- 09/10 – 2310, 2311, 2312, 2313, 2315, 2320, 2330, 2335, 2340, 2350, 2360, 1020, 1025, 1030, 1390
- 10/11 to 12/13 – SPARQ division within EPM

Energex then reconciled the SPARQ data to profit and loss reports from EPM. The SPARQ data was reconciled to the following accounts:

- 4940 - Sparq Contractor
- 4945 - Contr- Sparq Asset Usage Fee

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

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

Recurrent Opex – Is the total of the Cost of Sales, Telecommunications Costs, Asset Usage Fee, Finance Fee & 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 have been reconciled to the SPARQ RIN information as detailed in Point 2 above.

Inventory is capitalised in Energex accounts and as such it has been excluded from the recurrent expenditure charge.

As the provision for annual leave and long service leave were held in Energex, when leave was taken by SPARQ employees who original employed by Energex, the expenses were invoiced to Energex via a SPARQ invoice and allocated against the balance sheet provision. Annual Leave in 08/09 and 09/10 which is treated as operating costs in SPARQ has been excluded as the costs went directly to the Balance Sheet for Energex to offset the existing provision.

Non-recurrent Opex, as per the definition, is deemed to be the Energex MOPEX payments. MOPEX costs are Energex project related costs which are 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 are costed to one separate Responsibility centre (for the period 08/09 RC 2310 and for the period 09/10 to 12/13 RC 1025) and were sourced from the relevant EPM report for that RC.

CAPEX

Client devices Capex – Client devices capex was identified from the Accounting Entry Report for each year, as extracted from Ellipse.

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.

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

Descriptor Metrics

Employee Numbers – The employee numbers were extracted directly from the Energex annual shareholders reports.

User Numbers – The number of users was extracted as the number of active IT system log-in accounts used during each year.

Number of Devices – The number of devices was extracted as the number of client devices used as provided by Sparq Solutions.

12.4 Estimates

Energex has not used estimated data in preparation of this RIN.

12.5 Explanatory notes

SPARQ Solutions does not prepare Regulatory Accounting Statements as it is not a regulated entity in its own right. However the financial data provided in table 2.6.1 is sourced from SPARQ Solutions financial systems and is verifiable by reference to its audited Statutory Accounts. In addition, the financial data used to determine costs specific to Energex (i.e. monthly billing invoices) has been subject to periodic Internal Audit reviews in the 2008/09 to 2012/13 period to demonstrate the integrity of cost allocation and billing processes to its clients.

The following items caused significant movement between financial years:

Recurrent expenditure CAPEX ($000s)

- 2009/10 - Newstead Fitout $4,535,176 (wo SD3106) and MS Enterprise Agreement $3,947,050

- 2010/11 - Newstead Fitout $3,244,640 (wo SD3106)

Client Devices CAPEX ($000s)

- 2011/12 - Toughbooks $3,308,719 (wo SD5059)

Non Recurrent Expenditure OPEX ($000s) - Relates to MOPEX expenditure

- 2011/12 - Blueprinting $2,031,526 (wo SD5025) and Ellipse 8 $3,557,536 (wo SD5003)

12.6 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice, has not materially changed in nature.

13 BoP 2.6-3 – Non-Network – Property

The AER requires Energex to provide the following information relating to Non-Network Expenditure for years 2008/09, 2009/10, 2010/11, 2011/12 and 2012/13.

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

These variables are a part of worksheet 2.6 – Non-Network Expenditure

Actual information was provided for all variables.

13.1 Consistency with CA RIN Requirements

Table 13.1 below 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 Equiupment" and "Other – 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	Energex records furniture as part of fixtures and fittings, however for the CA RIN they have been split out into "Other –

Requirements (instructions and definitions)	Consistency with requirements
related personal chattels (e.g. furniture) that should be reported under Non-network Other expenditure.”	Furniture” to align to the AER requirements.

Actual information was provided in the Buildings and Property service subcategory of Non-Network Expenditure under the asset categories of Buildings and Property, Other – Plant & Equipment and Other – Office Furniture.

13.2 Sources

- EPM – FIN032 Divisional Profit and Loss
- Ellipse – “Accounting Entry Report – incl Proj & WO Desc (ECA90W)”
- Regulatory Accounts

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

Table 13.2: Information sources

Variable	Source
Building & Property Expenditure – OPEX ($000’s)	Profit and Loss Report by RC 2510 & 3600 Accounting Entry Report by Activity 62010 and RC 2510 for Non-Regulated activities
Building & Property Expenditure – CAPEX ($000’s)	Regulatory Accounts
Other – Other – CAPEX ($000’s) Other – Office Furniture – CAPEX ($000’s) Other – Plant & Equipment – CAPEX ($000’s)	Fixed Asset Register extract for Newstead project Accounting Entry Report by RC 2510 for CapexAccounting Entry Report by RC 2510 for Capex

13.3 Methodology

13.3.1 Approach

Energex applied the following approach to obtain the required information:

OPEX

The profit and loss statement was run from EPM by financial year for opex for the responsibility centres 2510 – Property and 3600 - Network Property Data & Coordination.

Non-regulated activities were identified by financial year using the accounting entry report run for activity 62010 and responsibility centre 2510. As the profit and loss statement includes non-regulated activities, these have been subtracted to reflect SCS expenditure only.

Energex applied the following approach to obtain the required information for Non Network Property Opex for 2008/09 to 2012/13:

a. Obtained the full Profit and Loss reports for Property (RC 2510) and Asset Management (RC 3600). Also obtained the partial Profit and Loss report for the whole of Energex for elements, Land Tax (5320), Rent & Leases – Land & Buildings (5400) and Rates (5410).

b. Land Tax, Rent & Leases – Land & Buildings and Rates was allocated between Network and Non Network Property Opex expenditure based on the following:

   - Land Tax – The Land Tax for the period 2008/09 to 2012/13 was allocated based on the split of the 2012/13 actual tax bill between Corporate (Non Network), Network and Coporate / Network Shared Sites. The properties allocated to Corporate / Network Shared Sites have been assumed to be Corporate in nature as the majority of the site would be used for Corporate activities. The split between Network and Non Network is 75.3% and 24.7% respectively. This percentage has been applied to period 2008/09 to 2012/13.

   - Rent & Leases – Land & Buildings – Up to 2012, Non Network rent was allocated to Responsibility Centre 2510. Network rent was allocated to responsibility centres apart from 2510. The allocation of Network and Non Network rent for the 2008/09 to 2011/12 is based on the actual spend. In 2012/13, a restructure resulted in all rent expenditure being allocated to responsibility centre 2510. As a result of the restructure which was part way through 2012/13, Network rent expenditure was allocated to RC 2510, the portion to be allocated to the Network was based on the average rent per year from RC 3600 for the period 2009/10 to 2011/12.

   - Rates – Up to 2012, Non Network rates was allocated responsibility centre 2510. Network rates was allocated to responsibility centres apart from 2510. The allocation of Network and Non Network rates for the 2008/09 to 2011/12 is based on the actual spend. In 2012/13, a restructure resulted in all rates expenditure being allocated to responsibility centre 2510. As a result of the restructure which was part way through 2012/13, Network rates expenditure was allocated to RC 2510, the portion to be allocated to the Network was based on the average rates per year from responsibility centres other than 2510 for the period 2008/09 to 2011/12.

The line “Total Indirect Expense excluding Oncosts & OH” from Divisional Profit and Loss allocated to “Building and Property Expenditure – OPEX”

The profit and loss took into account the direct expenditure including on-costs. Overheads and depreciation have not been included in the CA RIN as per the AER approved CAM.

CAPEX

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 were consolidated within worksheet 2.1, for details of this please refer to the basis of preparation for that worksheet. These figures also include non-system land purchases.

Energex records furniture as part of fixtures and fittings; however as per the AER definition of buildings and property, chattels (e.g. furniture) expenditure is not to be included in the stated figures. These amounts were therefore spilt out into “Other” non-network expenditure.

The value for furniture contained in the Buildings and Property figures was calculated in two parts. Firstly an accounting entry report was run to show the furniture expenditure within Energex for each regulatory year. Added to this was then the furniture costs calculated for the “Newstead” project.

The furniture costs for the “Newstead” project were calculated separately as the project was run through a building contractor and granular figures were not available for furniture. Another accounting entry report was generated to get the total figure for the “Newstead” project for each financial year. The furniture component of the project was then calculated by using the proportion of furniture asset values to total asset values found for the “Newstead” project in the fixed asset register.

The values for both regular Energex furniture capex and that calculated for the “Newstead” project were then added together to give the total for furniture and subsequently subtracted from the Buildings and Property figure. Furniture capex was then stated as “Office Furniture – Capex” in the other expenditure section as the aggregate over 5 years was greater than $1m.

Capex expenditure values for Manual Handling System and Generator held in Fleet part of the RIN has also been reclassified into “Other – Plant and Equipment”.

13.4 Estimates

Energex has not used estimated data in preparation of this RIN.

13.5 Explanatory notes

OPEX movement between financial years 2009/10 to 2010/12:

- The movement in OPEX is predominately due to increase cost of rent as result of paying rent for two sites in the transition phase to new site (Charlotte St to Newstead) and increased rental charges for new site (Newstead).

Percentage split applied to the breakdown of the Newstead:

- Details of the furniture expenditure were not available as the majority of costs relating to the Newstead project came through the building contractor, i.e. office workstations.
- Chairs and tables were supplied by independent supplier, but as part of the project completion, a quantity surveyors report was provided to capitalise the project, therefore, the fixed asset register split was used allocate Newstead project between fixtures and furniture.
- Energex records furniture as part of fixtures and fittings. As per the AER definition, furniture has been spilt out to “Other”.

13.6 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice, has 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 Zones 1, 2 and 3

- **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)**

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

Actual information was provided for Route Line Length and Cutting Cycle Frequency whilst estimated information was provided for all other variables.

14.1 Consistency with CA RIN Requirements

Table 14.1 below 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 based on the required cutting cycles in each geographical area. These cutting cycles are allocated by the growth rate of vegetation within that area.
"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 all Energex vegetation management zones is contained in appendix 4.

"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 section 1.1.5
"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 estimate the variables. Please refer to section 1.1.5 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 1.1.5
"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 below sets out the sources from which Energex obtained the required information.

Table 14.2: Information sources

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

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

Three vegetation management zones have been defined within the Energex network. These zones are based on the Energex vegetation management standard. This groups postcodes into zones based on the growth rates in each particular area and specifies the required cutting cycles based on these figures. These were considered appropriate divisions of the network as the cutting frequency is a key driver of the costs incurred for maintaining each zone. For the map of each zone with respect to the Energex network area please refer to Appendix 4.

Route Line Length within each Zone

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

An ArcGIS shapefile was developed to separate the Energex network into Urban/CBD and Rural categories based on the level of demand stated in section 1.1.4 above. This shapefile was then used to calculate the total population sizes of Urban/CBD and Rural spans.

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 (2654 spans for both Urban/CBD and Rural) were deliberately higher than the minimum calculated to ensure statistical relevance of the sampling. In zone 3 urban values were of insignificant quantity and were combined with the rural values.

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.

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.

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.

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.

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).

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

The length of vegetation corridors was estimated using 100% of the 132/110kV network and 10% of the rural network in 2 year and 4 year cycle areas. 10% is Energex's best estimate based on anecdotal evidence as no records are kept of corridor clearing below 132/110kV.

Average Frequency of Cutting Cycle

The average frequency of the cutting cycle is constant within each zone as this is how the vegetation management zones are defined. The cutting cycles are:

- Zone 1 – 1 Year
- Zone 2 – 2 Years
- Zone 3 – 4 Years

14.4 Estimates

Data for all variables excluding route line length and cutting cycles are considered estimates.

14.4.1 Justification for estimates

Energex did not have actual data available for these variables therefore data was estimated.

14.4.2 Basis for estimates

The field survey method for estimation was used for these five variables as it was 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.

14.5 Explanatory notes

Consistency between EB and CA RINs

There were three variances identified between vegetation management metrics supplied in both the category analysis RIN and the economic benchmarking RIN. The metrics identified to show a variance as well as an explanation of the variances are below.

Variable	Explanation
Route Line Length Within Zone (Km)	Route line length for the CA RIN and EB RIN will not reconcile. This is because subsequent to the submission of the unaudited response to the EB RIN, the AER changed its requirements for route line length. That is it required Energex to include underground segments in calculating route line length. In the CA RIN the definition of “route line length” is applicable only to overhead network. Given the absence of further direction on this issue through the AER’s Issues Register, the CA RIN includes overhead network only.
Number Of Maintenance Spans (0's)	The figures for Vegetation Management Spans were calculated from the same source data for both the EB and CA RINs and the same statistical sampling methodology was applied in both cases. However the CA RIN required a lower level of granularity, requiring disaggregation of the total area by zone. When the data was recalculated per zone the differences in the sample sizes, sample proportions and populations can lead to a similar yet not identical result (even though the totals within the source data add to those figures used for the EB RIN).
Average Number Of Trees Per Maintenance Span (0's)	These figures will vary as the AER changed the definition of a tree (to greater than 3m in height) between EB and CA RINs.

15 BoP 2.7-2 – Vegetation Management – Cost Metrics

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

For Zones 1, 2 and 3

- **Tree trimming (excluding hazard trees) ($'000's)**
- **Hazard tree cutting ($'000's)**
- **Ground Clearance ($'000's)**
- **Vegetation Corridors Clearance($'000's)**
- **Inspection ($'000's)**
- **Audit ($'000's)**
- **Contract Liaison Expenditure($'000's)**
- **Tree Replacement Program Costs ($'000's)**

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

15.1 Consistency with CA RIN Requirements

Table 15.1 below 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: c) areas where bushfire mitigation costs are imposed by legislation, regulation or ministerial order; and d) areas of the network where other recognised drivers affect the costs of performing vegetation management work."	Vegetation management zones have been defined based on the required cutting cycles in each geographical area. These cutting cycles are based upon many conditions including by the growth rate of vegetation within that area.
"Provide, on separate A4 sheets, maps showing: c) each vegetation management zone; and d) the total network area with the borders of each vegetation	The map of all Energex vegetation management zones is contained in

management zone.”	Appendix 4.
“For each vegetation management zone identified in 12.1 above, provide in the basis of preparation: d) a list of regulations that impose a material cost on performing vegetation management works (including, but is not limited to, bushfire mitigation regulations); e) a list of self-imposed standards from Energex’s vegetation management program which apply to that zone; and f) an explanation of the cost impact of regulations and self-imposed standards on performing vegetation management work.”	Please refer to section 1.1.5
• 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 had been reported in 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 has not been reported as this is not recorded separately
• 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 expenditure has not been reported as this is not recorded separately
• 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 has not been reported as this is not recorded separately

• Annual *vegetation management* expenditure across all categories and zones must sum up to the total *vegetation management* expenditure each year. In table 2.7.2, add any other *vegetation management* expenditure not requested in any other part of *regulatory template* 2.7 (or added in *regulatory template* 2.8) in 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 below sets out the sources from which Energex obtained the required information.

Table 15.2: Information sources

Variable	Source
All Variables	Corvu and MER ECA90W

15.3 Methodology

NAMP (Network Asset Management Plan) line costs were extracted from Corvu for each year of the 5 year period and then mapped to the RIN categories.

This information was then apportioned to the zones based on costs captured for each postcode trimmed.

15.3.1 Assumptions

The costs for each zone were apportioned on a pro rata basis as the NAMP lines are not split by zone.

Tree trimming – these costs are captured under NAMP lines VG02 (11kV - Vegetation Sector Based Distribution) and VG05 (LV - Customer Requested Vegetation). Costs captured by post code were used to apportion the costs between zones for financial years 2011, 2012 and 2013. As post code information was not captured before this, an average percentage based on the years 2011-2013 was used for the 2009 and 2010 financial years.

Hazard tree cutting – these costs are captured under NAMP lines VG03 (33kV VTA) and VG04 (11kV VTA). These were then apportioned to each of the zones based on an approximation of trimming in each zone.

Vegetation Corridor clearance – these costs are captured under NAMP line VG01 (Transmission clearance zone maintenance). This only captures costs for the 132 kV and 110 kV networks, the corridor clearing costs for 33 kV and below lines are apportioned to Tree trimming.

Tree replacement costs – for financial years 2012 and 2013 this is captured under standard jobs linked to NAMP line VG06 (Vegetation – Tree Replacement MOU's). In previous years these costs were captured under the same standard jobs, but linked to NAMP line VG02. For 2009, 2010 and 2011, these costs were excluded from NAMP VG02 and reported as tree replacement costs for this template.

Contractor Liaison Expenditure – Energex captures these costs as an indirect cost and are therefore not included in this template.

15.3.2 Approach

Definition of Vegetation Management Zones

Three vegetation management zones have been defined within the Energex network. These zones are based on the supplier managed programs which are covered under the "Energex Standing Offer for services agreement" with Energex contracted services providers . This groups postcodes into zones based on many factors including the growth rates in each particular area and specifies the required cutting cycles based on these values. These were considered appropriate divisions of the network as the cutting frequency is a key driver of the costs incurred for maintaining each zone. For the map of each zone with respect to the Energex network area please refer to Appendix 4.

15.4 Estimates

All data has been apportioned to the zones based on the actual costs for the financial year.

15.4.1 Justification for estimates

Energex has apportioned actual data into the categories required as costs are not captured by zones.

15.5 Explanatory notes

Not Applicable

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.

Estimated information was provided for all variables.

16.1 Consistency with CA RIN Requirements

Table 16.1 below 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 each 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 all regulatory years.

Estimated information was provided for all variables.

16.2 Sources

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

Table 16.2: Information sources

Variable	Source
No of fire starts	Service Call Management Database (SCM) Network Daily Outage Report

16.3 Methodology

The number of fire starts was determined from service calls logged in the Service Call Management Database (SCM) and from the Network Daily Outage report (for fire starts not logged in SCM). Each service call and outage was analysed and then summed together to obtain how many fire starts there was 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 Service Call Management Database (SCM) records incoming calls from the public, fire brigade, police, Energex field staff and emergency services. These incoming calls become service requests (SR). All service requests were filtered and extracted from the SCM to obtain the SR jobs involving fire.

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

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

4) The Network Daily Outage report figures were also analysed as some incidents are not logged in SCM. All outages were filtered to show only those that related to fire starts and these were added to the totals obtained from SCM to give the final figures.

16.4 Estimates

16.4.1 Justification for estimates

While the figures for fire starts have been taken directly from the Energex systems, anecdotal evidence suggests that post incident investigations can identify fires not reported through SCM or the Network Daily Outage Report.

16.4.2 Basis for estimates

The number of fire starts that are not reported through SCM or the Network Daily Outage report cannot be determined as there is no available data for these incidents. The figures taken from these sources are therefore considered to be the best representation of the data able to be generated by Energex.

16.5 Explanatory Notes

Not Applicable

17 BoP 2.8-1 – Maintenance – Descriptor metrics

The AER requires Energex to provide the following information relating to table 2.8.1:

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

These variables are a part of worksheet 2.8 – Maintenance.

The following data is estimated:

- **Asset quantity - at year end**
  - **Service Lines – Number of Customers (000'S)**
- **Asset quantity inspected/maintained**
  - **All variables**
- **Average age of asset group**
  - **All variables**
- **Inspection and maintenance cycles – all data**

All remaining information is actual data.

17.1 Consistency with CA RIN Requirements

Table 17.1 below 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 to table 2.8

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
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
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
Adding rows for additional maintenance subcategories to indicate inspection or maintenance cycles (i.e. non-financial data) does not require disaggregating the corresponding financial data for those additional subcategories.	Financial data has been reported where applicable.
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 are not yet included in any other maintenance expenditure subcategory.	Extra lines have been added where applicable.

The following data is estimated:

- Asset quantity - at year end
  - Service Lines – Number of Customers (000'S)

- Asset quantity inspected/maintained
  - All variables
- Average age of asset group
  - All variables
- Inspection and maintenance cycles – all data

All remaining information is actual data.

17.2 Sources

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

Table 17.2: Information sources

Variable	Source
Asset quantity – At Year End	NFM/SIFT
Asset quantity inspected/maintained	Corvu POW 302 Reports
Average age of asset group	NFM
Inspection Cycle	Substation Asset Maintenance Policy (SAMP) and Mains Asset Maintenance Policy (MAMP)
Maintenance Cycle	Substation Asset Maintenance Policy (SAMP) and Mains Asset Maintenance Policy (MAMP)

17.3 Methodology

17.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

<u>Asset Quantities – At Year End</u>

Number of Poles (000'S)

- Customer Poles have been excluded
- All poles have been reported including streetlight poles
- All poles have been reported in thousands

Line Patrolled (Route km) (000'S)

- Total quantities are reported in Megametres.
- The conductor data does not include conductors that are 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) (000'S)

- Total quantities are reported in Megametres.
- 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.

<u>Asset Quantities – Inspected/Maintained</u>

- **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 at the end of each 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 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) will be costed and counted against a NAMP line which has been mapped to a different AER asset maintenance category, based on other assumptions (such as highest expenditure).

- Hence 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.

- **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 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 worksheet 8.2, 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.

- **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. The table below provides the apportionment between CBD and non-CBD underground cable.

Cable Category	Length of cable	Percentage of total
CBD	87,328 metres	1.71%
Network	5,116,490 metres	100.00%

17.3.2 Approach

Energex applied the following approach to obtain the required information:

<u>Asset Quantity – At Year End</u>

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:

   - The pole material
   - The original installation year
   - The number of poles.

2) Poles that have a material type of plastic have been excluded.

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) For each year the pole quantity was calculated as the sum of poles installed up to and including the appropriate year. These figures have been reported in thousands.

Service Lines – Number of Customers (000'S)

The number of service lines for 2013 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.

The assets at year end for service lines was calculated by taking the number of service lines calculated for the age profile for 2012/13 and subtracting annual new connections extracted from MARS for each subsequent year.

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

Overhead Assets – Line Patrolled (Route km) (000'S)

1) A report was run from NFM that gave the Energex overhead conductor values for each year broken down by:

   - Conductor sizing category (Imperial, Metric or Other)
   - The circuit for each conductor
   - 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, assets that have been sold to customers and Energex believes that there is a benefit to continue to store this data, the data has not be removed from NFM.

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.

Customer Conductor	*2008/09*	*2009/10*	*2010/11*	*2011/12*	*2012/13*
Length	8.14	8.10	7.52	7.51	8.07

3) 110/132kV feeders 711 & 712 have been identified as Non-Energex feeders and have been excluded from all years reported.

Excluded Feeders	*Quantity (km)*
711	22.11
712	22.11

4) Lengths have been reported in Megameters (km 000's)

Underground Cable Length (Route km) (000'S)

1) A report was run from NFM that gave the Energex underground cables broken down by:

   - Snapshot point for each year (2009 to 2013)
   - Cables constructed voltage is equal to or less than 22kV or greater than 22kV
   - 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 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 cables, it has been assumed that where a cable is connected to only customer assets then that cable is also customer owned.

Customer Cable	*2008/09*	*2009/10*	*2010/11*	*2011/12*	*2012/13*
Length (km)	17	17	16	15	14

3) Lengths have been reported in Megameters (km 000’s)

Distribution Substation – Number of Installed Transformers (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

   - Location – Zone or Distribution
   - Transformer Type – Power or Distribution
   - Has Customers - Yes or No
   - 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 category

   a. Location equals Distribution (DIST)

3) Transformer quantities are reported in thousands.

Distribution Substation – Number of Switches (000'S)

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009 to 2013 that detailed the circuit breakers and reclosers in the Energex network with the following corresponding information:

   - Snapshot date
   - Equipment type
   - Install date

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

This report excludes all asset indicated as customer owned.

2) Switch quantity has been reported in the thousands.

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 of each financial year 2009 to 2013 for all circuit breakers in the Energex network with the following corresponding information:

   - Rating of low voltage
   - Snapshot date
   - First recorded install date

3) Number of circuit breakers have been reported in the thousands.

Distribution Substation – Number of Distribution Substation Properties Maintained (000'S)

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009 to 2013 that detailed all sites in the Energex network with the following corresponding information:

   - Snapshot Date
   - Sites System Unique Number
   - 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 asset indicated as customer owned.

2) Sites have been reported in the thousands.

Zone Substation – Number of Zone Substation Transformers (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

   - Location – Zone or Distribution

- Transformer Type – Power or Distribution
- Has Customers - Yes or No
- 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. Transformer Type equals Power (TR-PW)

    b. Location equals Zone

3) Quantities reported in thousands

Zone Substation – Number of Distribution Transformers Within Zone Substations (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

    - Location – Zone or Distribution
    - Transformer Type – Power or Distribution
    - Has Customers - Yes or No
    - 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. Transformer Type does not equal Power (TR-PW)

    b. Location equals Zone

    c. Has Customer equal Yes

3) Quantities reported in thousands

Zone Substation – Number of HV Transformers (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

    - Location – Zone or Distribution
    - Transformer Type – Power or Distribution
    - Has Customers - Yes or No
    - 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. Transformer Type does not equal Power (TR-PW)

    b. Location equals Zone

    c. Has Customer equal No

3) Quantities reported in thousands

Zone Substation – Other Equipment (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 for Connectivity Assets and Non Connectivity Assets:

    - Snapshot Date
    - Installation Date
    - 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 also excluded the following assets

    - Transformers
    - Tee Off
    - Cable Boxes
    - Circuit Transformers

- Cable Joints
- Fault Indicators
- Switch Fuses

The Non Connectivity Assets report included the following assets

- Ring main units
- 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.

2) Reports were combined

3) Quantities reported in thousands

Zone Substation – Number of Zone Substation Properties Maintained (000'S)

1) A report was extracted from SIFT for each year from 2009 to 2013 for Bulk and Zone substations that detailed the number of Zone Substations properties that Energex maintains.

2) Quantities reported in thousands

Public Lighting – Number of Public Lights Maintained (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the streetlights in the Energex network with the following corresponding information:

   - Snapshot Date
   - Installation Date
   - 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

3) Quantities reported in thousands

Subtransmission Asset Maintenance – For DNSPs with Dual Function Assets

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

Number of Distribution Transformers, Regulators, Sectionalisers and Reclosers

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the distribution transformers, regulators, sectionalisers and reclosers in the Energex network with the following corresponding information:

    - Snapshot Date
    - Installation Date
    - 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 excludes all asset indicated as customer owned.

2) Quantities reported in thousands

Zone Substation Inspection – All Substation Assets – Number of Zone Substation Properties Maintained (000'S)

1) Data reported is the same as stated for "Zone Substation – Number of Zone Substation Properties Maintained (000'S)" above. For the details of the methodology please refer to the relevant section above.

Zone Substation Inspection – All Zone Substation Assets – Number of Zone Substation Properties Maintained (000'S)

1) Data reported is the same as stated for "Zone Substation – Number of Zone Substation Properties Maintained (000'S)" above. For the details of the methodology please 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 (000'S)" above. For the details of the methodology please refer to the relevant section above.

All Underground Feeder Assets

1) Data reported is the total underground feeder length. This is the sum of "Underground Cable Length (Route km) (000'S)" stated above. For the methodology please refer to the relevant section above.

Asset quantity inspected / maintained

1) POW302/Corvu reports for each year were used to identify the work orders that related to each of the NAMP lines.

2) This data was extracted for activities codes 41100, 41200 and 41600 (2008-09 and 2009-10 only), which represent maintenance activities. Data was also extracted from 41500 for activity VG09 (2012-13 only).

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 POW302 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) The quantity of assets inspected/maintained for the following categories could not be determined from the POW302/Corvu reports as Energex does not capture the required data:

    - Pole Top, Overhead Line & Service Line Maintenance – Service Lines – Number of Customers
    - Pole Inspection and Treatment – All Poles – Number of Poles
    - Overhead Asset Inspection – All Overhead Assets – Line Patrolled (Route Km)
    - Network Underground Cable Maintenance: By Voltage – LV - 11 to 22 KV – Length (Km)
    - Network Underground Cable Maintenance: By Voltage – 33 KV and Above – Length (Km)
    - Network Underground Cable Maintenance: By Location – CBD – Length (Km)
    - Network Underground Cable Maintenance: By Location – Non-CBD – Length (Km)
    - Underground Feeder Asset Inspection – All Underground Feeder Assets – Length (Km)
    - Pilot Cable Inspection And Maintenance – All Pilot Cables (Copper & Fibre) – Length Meters

    Estimates were calculated for these variables by dividing the “Asset Quantity at Year End” figures in each respective year by the “Maintenance Cycle” value.

6) A number of assets reported in the “Asset Quantity Inspected/Maintained” under “Zone Substation Inspection” were identified to relate to “Distribution Asset

Inspection”. The number of inspections to be redistributed was determined by firstly analysing the activity within each standard job description under the applicable NAMP line for one year. The analysis of the standard job descriptions then generated a percentage that related to “Distribution Asset Inspection”. This percentage within “Zone Substation Inspection” was then reallocated to “Distribution Asset Inspection” for each year.

7) 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.

8) A zero balance is shown for “SCADA & Network Control Maintenance – Number of Units Installed” in 08/09. This was due to the program “Telecoms Ancillary Inspections” which was mapped to that particular line not starting until 2010.

9) A zero balance is shown for “Distribution Substation Switchgear“. Only a new maintenance program was reported in this line which was implemented in 2011/12 (DS09 - retrofit safelink RMU) to replace faulty mechanisms.

Average age of asset group

Pole Tops and Pole Inspection – Number of Poles

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2-1 for aging calculations

2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

For example 2010 was the average age of all assets from 1911 to 2010.

Service Lines – Number of Customers (000'S)

The number of service lines and their age profile for 2013 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.

The average age of service lines for prior years was calculated by removing new assets installed in each year (as identified when calculating the asset quantities above) and taking the average age of the remaining assets.

Overhead Assets – Line Patrolled (Route km) (000'S)

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2-1 for aging calculations

2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

Underground Cable Length (Route km) (000'S)

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2-1 for aging calculations
2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

Distribution Substation – Number of Installed Transformers (000'S)

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2-1 for aging calculations
2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

Distribution Substation – Number of Switches (000'S)

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009 to 2013 that detailed the circuit breakers and reclosers in the Energex network with the following corresponding information:
2) Snapshot date
3) Equipment type
4) Install date
    a. This report includes all circuit breakers and reclosers that were commissioned, at the relevant point in time.
    b. This report excludes all asset indicated as customer owned.
5) The average age was then calculated using the installation dates of the assets extracted for each year.
6) 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 of each financial year 2009 to 2013 for all circuit breakers in the Energex network with the following corresponding information:

- Rating of low voltage
- Snapshot date
- First recorded install date

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

Distribution Substation – Number of Distribution Substation Properties Maintained (000'S)

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009 to 2013 that detailed all sites in the Energex network with the following corresponding information:

    - Snapshot Date
    - Sites System Unique Number
    - 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 (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

    - Location – Zone or Distribution
    - Transformer Type – Power or Distribution
    - Has Customers - Yes or No
    - 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. Transformer Type equals Power (TR-PW)

b. Location equals Zone

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 (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

- Location – Zone or Distribution
- Transformer Type – Power or Distribution
- Has Customers - Yes or No
- 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. Transformer Type does not equal Power (TR-PW)

b. Location equals Zone

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 (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the transformers in the Energex network with the following corresponding information:

- Location – Zone or Distribution
- Transformer Type – Power or Distribution

- Has Customers - Yes or No
- 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. Transformer Type does not equal Power (TR-PW)

    b. Location equals Zone

    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 (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 for Connectivity Assets and Non Connectivity Assets:

- Snapshot Date
- Installation Date
- Quantity

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

Connectivity Asset report also excluded the following assets

- Transformers
- Tee Off
- Cable Boxes
- Circuit Transformers
- Cable Joints
- Fault Indicators

- Switch Fuses

The Non Connectivity Assets report included the following assets

- Ring main units
- 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.

2) 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 (000'S)

1) A report was extracted from NFM for each year from 2009 to 2013 for Bulk and Zone substations that detailed 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 (000'S)

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2-1 for aging calculations
2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

Subtransmission Asset Maintenance – For DNSPs with Dual Function Assets

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

Number of Distribution Transformers, Regulators, Sectionalisers and Reclosers

1) A report was extracted from NFM for each year from 2009 to 2013 that detailed the distribution transformers, regulators, sectionalisers and reclosers in the Energex network with the following corresponding information:

   - Snapshot Date

- Installation Date
- 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 excludes all asset indicated as customer owned.

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

3) Average age was calculated from the installation date.

Zone Substation Inspection – All Substation Assets – Number of Zone Substation Properties Maintained (000'S)

1) Data reported is the same as stated for "Zone Substation – Number of Zone Substation Properties Maintained (000'S)" above. For the details of the methodology please refer to the relevant section above.

Zone Substation Inspection – All Zone Substation Assets – Number of Zone Substation Properties Maintained (000'S)

1) Data reported is the same as stated for "Zone Substation – Number of Zone Substation Properties Maintained (000'S)" above. For the details of the methodology please 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 (000'S)" above. For the details of the methodology please refer to the relevant section above.

All Underground Feeder Assets

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2-1 for aging calculations

2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

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) and Mains Asset Maintenance Policy (MAMP). These two policies have been in place for the previous five years. However, as frequencies have been revised over the course of this five-year period, the most current frequencies have been reported.

2) 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 most common or biggest population of equipment in the network. This is largely due to each year being unique to the volumes of each type of equipment that is triggered for maintenance.

3) If the Asset Category was mapped to a single NAMP line which did not have a routine maintenance or inspection cycles (that is, the NAMP line was for a program completely reactive in nature), a five year cycle was applied to the maintenance cycle and inspection cycle. This was on the basis that all projects would have been visited under other NAMP lines over this period. It should also be noted that some Asset Categories are not explicitly inspected or maintained unless required, for example, 'NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE'. For these Asset Categories, the inspection cycle is covered by the Underground feeder asset inspection category. Any maintenance will only occur if it is required.

4) 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, were given a maintenance cycle the same as the inspection cycle. This is largely due to maintenance being driven through the inspections and not routinely carried out.

5) 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, were given an inspection cycle the same as the maintenance cycle. This is largely due to inspections being carried out at the same time of maintenance.

6) Cycle frequencies were reported in the RIN template on the above basis and therefore will not always have associated expenditure (as expenditure may have occurred against another NAMP line which was mapped to another Asset category).

17.4 Estimates

The following data is estimated:

- Asset quantity - at year end
  - Service Lines – Number of Customers (000'S)
- Asset quantity inspected/maintained
  - All variables
- Average age of asset group
  - All variables

- Inspection and maintenance cycles – all data

All remaining information is actual data.

17.4.1 Justification for estimates

Asset quantity - at year end

Service Lines – Number of Customers (000'S)

- These figures were based on the figures calculated for table 5.2 which were also estimated. As such the data stated is considered estimated.

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 POW302/Corvu 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.

Average age of asset group

Zone Substation – Number of Zone Substation Transformers (000'S)

- These figures are estimated as when the equipment age is not available then the site age is used as the estimated value.

Zone Substation – Number of Zone Substation Properties Maintained (000'S)

- 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 as only asset history on implementation of NFM is currently known.

All other Maintenance Categories

- These figures were based on the figures calculated for table 5.2 which were also estimated. As such the data stated is considered estimated.

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 figures. Within this aggregation certain assumptions were made that lead the figures to be estimated.

17.4.2 Basis for estimates

A large number of the estimates have been based on data calculated for worksheet 5.2. For the specific methodology please refer to the basis of preparation for that worksheet.

Asset quantity inspected/maintained

- Certain values for assets inspected/maintained have been categorised into the categories required in 2.8.1 by mapping the Energex NAMP lines to the categories required. The values for “Zone Substation Inspection” and “Distribution Asset Inspection” were reallocated as the NAMP lines did not accurately reflect the category being reported.
- The remaining categories were calculated by dividing the “Asset Quantity at Year End” figures in each respective year by the “Maintenance Cycle” value.
- For details of the methodology by which each variable was calculated please refer to the methodology section above.

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 most common or biggest population of equipment in the network. This is largely due to each year being unique to the volumes of each type of equipment that is triggered for maintenance.
- If the Asset Category was mapped to a single NAMP line which did not have a routine maintenance or inspection cycles (that is, the NAMP line was for a program completely reactive in nature), a five year cycle was applied to the maintenance cycle and inspection cycle. This was on the basis that all projects would have been visited under other NAMP lines over this period. It should also be noted that some Asset Categories are not explicitly inspected or maintained unless required, for example, ‘NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE’. For these Asset Categories, the inspection cycle is covered by the Underground feeder asset inspection category. Any maintenance will only occur if it is required.

17.5 Explanatory notes

Not Applicable

18 BoP 2.8-2 – Maintenance – SCADA and Network Control Maintenance

The AER requires Energex to provide the following variables relating to table 2.8.1 Maintenance Descriptor Metrics:

- **SCADA and Network Control Maintenance**
- **Protection Systems Maintenance**

Energex has also added the variable:

- **Pilot Cables**

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

- **Total Asset volumes per financial year**
- **Average Age of Asset per financial year**

These variables are a part of worksheet 2.8 – Maintenance.

Estimated information was provided for all variables covered in this basis of preparation.

18.1 Consistency with CA RIN Requirements

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 have been reported in 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 below
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.	Demonstrated in section 18.3.2 below

Estimated information was provided for all variables covered in this basis of preparation.

18.2 Sources

Table 18.2 below sets out the sources from which Energex obtained the required information associated with the Basis of Preparation..

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
Pilot Cable	CBMD

18.3 Methodology

Total Asset numbers per financial year

SCADA Network and Control Maintenance

This variable was determined by adding up the total number of the below assets for the required financial year using age profile.

- RTUs, IED, Microwave Links, DSS Head Ends, DSS Radios and Multiplex equipment (which included MPLS nodes).

Various techniques where utilised to create the per financial year age profiles and to correct the data for each financial year, see the estimation section below for further details.

Protection System Maintenance

This variable was determined by extracting the total installation base from the IPS system and then correcting the data for the relevant financial year by analysing "Discarded" records (units that had been removed or replaced).

Pilot Cables

This variable was determined by extracting total meters installed per annum from the CBMD database.

Average age of Assets per financial year

SCADA Network and Control Maintenance

These variables were generated using the per financial year age profile and determining the average age.

Protection System Maintenance

These variables were generated using the per financial year age profile and determining the average age.

Pilot cables

These variables were generated using the per 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 have been replaced.
- Asset 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 the BOP.

18.3.2 Approach

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

Total Assets per financial year

1) Obtain age profile data
2) Prepare the age profile based for 12/13 financial year by correcting the data collected above (remove relevant records or estimate total numbers)
3) For financial years before 12/13 remove installations identified in non-applicable financial years (e.g. for 11/12 simply remove installs from 12/13, for 10/11 remove both 11/12 and 12/13)
4) Correct age profile by adding any information about units that were replaced in the financial years that were removed.
5) Calculate total assets by adding up totals identified in the age profile.

Average Age of Asset per financial year

1) Using the age profiles per financial year generated above, calculate the average age of the asset base for each financial year.

Asset age profiles

The assumptions and estimates 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 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 asset, the total population as at end of 12/13 was estimated and was spread based on when fibre optic cable was installed. Total number of Matrix nodes as reported from the SAM database was then added to the numbers generated
- Pilot Cables – The CBMD application database was queried to determine commissioning dates for each point to point link.

18.4 Estimates

Estimated information was provided for all variables covered in this basis of preparation.

18.4.1 Justification for estimates

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

1) **Estimation of age profiles for previous financial years -** it was necessary to estimate installation date of replaced equipment in some cases as no data was

available. In these cases the average asset age was utilised to estimate when the assets are likely to have been installed.

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 estimates

1) **Estimation of age profiles for previous financial years** - where no information was available about the age of a replaced unit, the average asset age was utilised to estimate when the assets are likely to have been installed.

2) **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

Not Applicable

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 worksheet 2.8 – Maintenance

19.1 Consistency with CA RIN Requirements

Table 19.1 below 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.	Access Tracks previously reported as vegetation have been included in the maintenance template and excluded from vegetation template
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 to table 2.8

All data provided for maintenance costs are estimated as incurred.

19.2 Sources

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

Table 19.2: Information sources

Variable	Source
Actual Costs by work order	SQL query that extracted data

	from the Ellipse GL tables
NAMP Line / Work Order alignment	Corvu POW 302 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 have been 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.

- 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’s NAMP codes have evolved over the last 5 years as reporting requirements have changed. Energex now has separate NAMP lines for 'planned' and 'unplanned' maintenance work. When a NAMP code was split into

‘Planned’ and ‘Unplanned’, the original NAMP code became the ‘Planned’ NAMP, and the new NAMP code became the ‘Unplanned’ NAMP. These splits predominately occurred in the 2011-12 financial year when reporting against Planned & Reactive work was introduced. Prior to 2011-12, the reactive/unplanned components of these NAMP codes have been aligned to the ‘Routine Maintenance’ costs as per current NAMP mapping.

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.

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. The table below provides the apportionment between CBD and non-CBD underground cable.

	Length of cable	Percentage of total
CBD	87,328 metres	1.71%
Entire network	5,116,490 metres	100.00%

19.3.2 Approach

Energex applied the following approach to obtain the required information:

- POW302/Corvu 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
  - AMOUNT

- This data was extracted for activities codes 41100, 41200 and 41600 (2008-09 and 2009-10 only), which represent maintenance activities. Data was also extracted from 41500 for activity VG09 (2012-13 only).
- 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 POW302 reports as being associated with specific NAMP codes were reviewed and assigned to NAMP codes where possible based upon the project / work order description.
- Certain costs reported in the under “Zone Substation Inspection” were identified to relate to “Distribution Asset Inspection”. The costs to be redistributed were determined by firstly analysing the amount within each standard job description under the applicable NAMP line for one year. The analysis of the standard job descriptions then generated a percentage that related to “Distribution Asset Inspection”. This percentage within “Zone Substation Inspection” was then reallocated to “Distribution Asset Inspection” for each year.

19.4 Estimates

All data provided in table 2.8.2 is estimated information.

19.4.1 Justification for estimates

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

19.4.2 Basis for estimates

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

The values for “Zone Substation Inspection” and “Distribution Asset Inspection” were reallocated as the NAMP lines did not accurately reflect the category being reported

19.5 Explanatory notes

Not Applicable

20 BoP 2.9-1 – Emergency Response

The AER requires Energex to provide the following information relating to Emergency Response Expenditure:

- **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**

These variables are a part of worksheet 2.9 – Emergency Response.

Actual information was provided for all variables.

20.1 Consistency with CA RIN Requirements

Table 20.1 below 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 provide the following - • Total emergency response expenditure by regulatory year • Emergency response expenditure attributable to major events by regulatory year • Emergency response expenditure attributable to major event days by regulatory year	The variables supplied in Table 2.9 are across the entirety of the Energex network for each regulatory year.
• 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
Response to Issue 130 – CA RIN Issues Register: "The instructions for template 2.9 ask for:	Total emergency response costs have been reported in section A. Total opex for specifically

• (A) Total emergency response opex • (B) Opex for major event (defined) and for major storms (defined) • (C) Opex for MEDs (defined). (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 we would expect to have visibility of opex on a daily basis under item (C) where the MED event is identified. We also wouldn't necessarily expect daily opex for events identified in (C) to sum up to amounts reported for the same event in (B) given other activity on those days."	identified major events have been reported in section B. Opex for MEDs have been reported in section C.
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 nonrelated entities."*	Energex has reported costs from two activity codes, both of which conform to the AER's definition of Emergency Response.

Actual information was provided for Emergency Response Expenditure.

20.2 Sources

Table 20.2 below 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 Data Warehouse POW005 Transaction

	Report
Total Emergency Response Expenditure	Ellipse Report ECAA01

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) has been 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:

1) Costs relating to Emergency Response activities are recorded under the activity headings 41300 and 41400.

2) Overall costs for activities 41300 and 41400 were extracted from Ellipse using MER Report ECAA001.

3) Major event day (MED) date related costs at a work order/ transaction level were extracted using an adapted EPM report (POW005). (Amendment to report was to select specific financial activities, as opposed to default choices of Project / Work Order / Date ranges)

4) In both cases above, data was extracted for FY's 2008/09, 2009/10, 2010/11, 2011/12, and 2012/13

5) Expenses were filtered to include only direct costs and on costs (overheads excluded), based on account elements (that is, account elements 8100, 8101 and 8104 were excluded.)

6) Costs for identified major events and MEDs were extracted based upon the transaction date of the MEDs, as outlined above. The table below provides a list of the major events and the MEDs that occurred during the period.

Year	Major events	Major event days
2008-09	• Storms struck ENERGEX on 16/11/08 • Storms struck ENERGEX on 20/11/08 • Heavy rain, high winds and storms struck ENERGEX on 20/05/09	• 16/11/2008 • 20/11/2008 • 20/05/2009
2009-10	• Storms struck ENERGEX on 13/10/09 • Storms struck ENERGEX on 22/12/09	• 13/10/2009 • 22/12/2009
2010-11	• Storms struck ENERGEX on 15/12/10 • Storms struck ENERGEX on 16/12/10 • Major flooding of Brisbane and Bremer Rivers between 09/01/11 and 12/01/11 • Storms struck ENERGEX on 18/01/11 • Storms struck ENERGEX on 21/0211	• 15/12/2010 • 16/12/2010 • 09/01/2011 • 10/01/2011 • 11/01/2011 • 12/01/2011 • 18/01/2011 • 21/02/2011
2011-12	• Storms struck ENERGEX on 17/11/12	• 17/11/2012
2012-13	• Storms and Flooding Impacted ENERGEX Network between 26/01/13 and 29/01/13 • Storms struck ENERGEX 24/03/13	• 26/01/2013 • 27/01/2013 • 28/01/2013 • 29/01/2013 • 24/03/2013

7) 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:

- 16/11/2008
- 20/11/2008
- 20/5/2009
- 13/10/2009
- 22/12/2009
- 15/12/2010
- 16/12/2010
- 9/1/2011
- 10/1/2011
- 11/1/2011
- 12/1/2011
- 18/1/2011
- 21/2/2011
- 17/11/2012
- 26/1/2013
- 27/1/2013
- 28/1/2013
- 29/1/2013
- 24/3/2013

20.4 Estimates

No estimates were made in providing the data (all data was based on actual values).

20.5 Explanatory notes

Not Applicable

21 BoP 2.10-1 – Overheads Expenditure

Overheads Expenditure – Network and Corporate Overheads

The AER requires Energex to provide the following variables relating to Table 2.10.1 Network Overhead

- **Allocation to Standard Control Services**
  - **Disaggregate network operating costs into six subcategories – network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions, other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements**
- **Allocation to Alternative Control Services**
  - **Disaggregate network operating costs into six subcategories – network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions, 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 – network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions, other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements**

The AER requires Energex to provide the following variables relating to Table 2.10.2 Corporate Overhead

- **Allocation to Standard Control Services**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting Statements not included in any other overhead subcategory**
- **Allocation to Alternative Control Services**
  - **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 for 2009 and 2010 is considered to be Estimated.
Actual information was provided for all tables for the period 2011 to 2013.

21.1 Consistency with CA RIN Requirements

Table 21.1below 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

Table 2.10.1 in CA RIN
 	
Appendix E Clause 14.3 of CA RIN
 	
14.3 For the avoidance of doubt, the following expenditures must be provided in regulatory template 2.10:
(a) Table 2.10.1 Network Overhead – 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
(iii) *network control* and operational switching
(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).
(b) Table 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
	Network overheads expenditure for 2011-2013 has been categorised into the following subcategories:
	
	Mandatory
	• Network Management
	• Network Planning
	• Network Control and Operational Switching Personnel
	• Quality and Standards Function
	• Project Governance and related Functions
	    o Logistics and stores (POW Material Management)
	    o Procurement
	    o Project Governance – Supervision
	    o Project Governance – Works Management
	• Training and Development
	• OHS
	• Customer Services
	
	Optional
	• Meter Reading, Network Billing and Metering Support
	• DSM Initiatives
	• Levies
	• Solar feed-in tariffs
	• Network Property

(v) feed-in tariffs (vi) demand management expenditure (vii) levies	
Table 2.10.2 in CA RIN Appendix E Clause 14.3 of CA RIN (c) Table 2.10.2 Corporate Overhead – 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 (x) non-network IT support.	Corporate overheads expenditure for 2011-2013 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
Definitions for mandatory subcategories of network overhead expenditure: network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions.	Appendix F: Definitions of the CA RIN outlines the definitions of: Network overhead; Network planning; Network Control; Operational Switching Quality Standards and Functions; Project Governance; Works Management

Estimated information is provided in Template 2.10 Overheads for all items for the 2009 and 2010 years.

Actual information was provided in the overhead expenditure tables for both Network and Corporate Overheads for the years 2011 to 2013.

21.2 Sources

All information has been sourced from the Annual RINs, supporting work files or general ledger reports as detailed in Table 21.2.

Table 21.2: Information sources

Variable	Source
Network Overhead – 2009 & 2010	Ellipse general ledger report and regulatory account workpapers
Network Overhead – 2011-2013	Ellipse general ledger report (ECAA01) Annual RINs and excel work files
Corporate Overhead – 2009 & 2010	Ellipse general ledger report and regulatory account workpapers
Corporate Overhead – 2011-2013	Ellipse general ledger report (ECAA01) Annual RINs and excel work files

21.3 Methodology

The approaches that were taken to report overhead expenditure into the categories in the CA RIN are outlined below. The methodology used for the prior Determination period (2009 and 2010) differs from that used for the current Determination period (2011-2013) as Energex had different Cost Allocation Methods (CAMs) for each period.

21.3.1 Assumptions

For 2009 and 2010:

1) the allocation percentages for shared service costs have been assumed to be the same for the entire year. The individual allocation driver percentages for the year have been aggregated into the CA RIN overhead expenditure sub-categories as per the functional mapping included as Appendix 5;

2) All capitalised overheads relate to Standard Control Services (SCS) only, as no Alternative Control Services (ACS) were capitalised during this period and Non-Regulated (NR) overheads are operating in nature;

3) Costs of implementing Full Retail Competition (FRC) have been disclosed in the functional area to which they relate, however no FRC costs were capitalised.

21.3.2 Approach

Energex applied the following approaches to obtain the required information for overhead expenditure for the relevant years.

2009 and 2010

1) Obtained general ledger reports that provide account balances for expenses, detailing the nature of the item 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 included in Appendix F to the CA RIN and the associated guidance provided in Appendix E to the CA RIN. The functional level mapping was undertaken to:

    a. Exclude non-regulated costs identified by Responsibility Centre and/or Activity;

    b. Exclude direct costs identified by Activity;

    c. Exclude costs identified by Element for allocated overheads, disposals, depreciation (except for shared services as applicable), dismantled assets and bad debts;

    d. Identify shared services costs as partially or fully allocated, in accordance with workpapers for the allocation of costs for the relevant years;

    e. Map remaining expenses to the functional areas as detailed in Appendix 5.

2) Shared services costs typically mapped to Corporate Overheads and network indirect costs typically mapped to Network Overheads.

    In addition, some items identified by Energex as direct costs and reported accordingly for annual RIN reporting, 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.

3) Corporate Overheads were identified as SCS, ACS or NR based on proportions for the aggregated allocation drivers for shared service functions mapped to functional areas.

4) Network Overheads were identified as SCS, ACS or NR based on proportions applicable for each year.

5) Amounts capitalised were then individually determined by reference to the functional mapping, the nature of the components and the CAM that applied for the period.

Total capitalised overheads equal the amounts identified in Template 2.1 Expenditure Summary.

6) Balances were proportionally allocated to match those included in the annual regulatory accounts for each year.

2011 to 2013

1) Obtained ECAA01 reports for the years 2011, 2012 and 2013. ECAA01 reports are financial reports run from the Ellipse general ledger system that provide account balances for expenses, detailing the nature of the item via codes that identify the group that incurred the dollars (responsibility centre), the work being performed (activity), and the type of expense (element).

2) Operating expenditure account balances within the ECAA01 report were then identified as being an overhead based on the definition provided for in the CA RIN. Once identified as an overhead, the operating expenditure items were categorised into functional areas based on the mandatory categories as defined in the CA RIN and additional categories as provided for in Energex's current annual RIN. The functional level mapping was undertaken based principally on responsibility centre and activity. Refer to Appendix 5 for more detail.

   Expenditure incurred in relation to network property has been identified as a specific network overhead. Prior to 2013 this expenditure was captured in a dedicated department. In 2013 an organisational restructure occurred rationalising the property functions with the network property function being transferred to the corporate property department. The department previously responsible for network property changed its focus and is now mapped to Quality Standards and Functions. The expenditure associated with network property for 2013 has been separately identified and continues to be reported as a network overhead.

3) Functional areas were then identified as being either:

   (a) a pooled cost – representing those costs allocated to direct control services in accordance with Energex's approved CAM. A portion of these costs are capitalised; or

   (b) a non-pool cost – representing those costs not allocated to individual services and remains as 100% operating expenditure.

   Pooled costs were allocated based on direct dollar spend.

4) Adjustments applied in the preparation of annual RINs 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 annual RIN.

21.4 Estimates

For 2009 and 2010, all information in Template 2.10 Overheads is considered to be estimated. This is due to the aggregations and assumptions applied to the available data to enable reporting in the CA RIN categories and sub-categories.

For 2011 to 2013, overhead expenditure as disclosed in the CA RIN is Actual.

21.5 Explanatory notes

1) In 2009 and 2010, Corporate Overheads for Field Support Services, IT and Communications, Property and Fleet included non-system asset depreciation which was allocated to services. With the change in CAM from 2011, depreciation is no longer allocated, which is reflected in the step change to these sub-categories. Refer to section 21.6 below for more information on the change in CAM.

2) Corporate Overheads for Corporate Restructuring began in 2012 as a result of Energex's conscious effort to reduce costs and employee numbers. This has resulted in the payment of termination benefits.

3) Corporate Overheads for Debt Raising Costs eventuated with the new Determination in 2011.

4) From 2011, Corporate Overheads allocation to ACS and Corporate Overheads capitalised reflect the change in CAM (refer to section 21.6 below). From this time, there has been specific identification of support costs attributed to SCS only and not capitalised.

5) The variability in Overhead before Allocation to Unregulated Services (both Network and Corporate) is a result of Energex progressively divesting its non-regulated businesses over time.

21.6 Accounting policies

Energex changed its CAM from the 2010-11 year and new regulatory control period to better align with its predominant role as a distribution business, and to align with the National Electricity Rules rules and Cost Allocation Guidelines.

Energex has not changed its CAM since the start of this Determination period.

21.7 Nature of the change

The change in CAM resulted in:

- Discontinuation of the capitalisation of non-system asset depreciation;

- Discontinuation of the allocation of shared services costs based on individual allocation drivers;
- Separate attribution of material oncosts (representing the cost of storing and handling materials which is directly attributable to inventory issues);
- Separate attribution of fleet oncosts (representing the cost of operating and maintaining vehicles owned or leased by Energex which is directly attributable to the labour utilised);
- Separate allocation of relevant support costs to unregulated activities;
- Specific identification of support costs as reported separately in the annual RIN; and
- Allocation of the remaining indirect expenditure as general overhead, allocated on the basis of total direct spend for individual services.

21.8 Impact of the change

Impacts of the change in CAM are explained above in section 21.5.

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 was provided for all labour categories defined by the AER and split into Corporate Overheads, Network Overheads and Direct Network Labour. The data was provided for years 2008/09, 2009/10, 2010/11, 2011/12 and 2012/13.

The AER requires Energex to provide the following information relating to Table 2.11.2 – Extra Labour Descriptor Metrics for Current Year:

- **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 was provided for all labour categories defined by the AER and split into Corporate Overheads, Network Overheads and Direct Network Labour.

All information is a part of Worksheet 2.11 - Labour

Estimated information was provided for all variables.

22.1 Consistency with CA RIN Requirements

Table 22.1 below 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 standard control services should be reported in the labour cost tables in 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 tables. Energex must break down its labour data (both employees and labour contracted through labour hire contracts) into the	Energex general ledger system (Ellipse) uses 17 digit account codes to capture the transaction information. This includes the department, functions being performed, product or service delivered to external customer and nature of income or expense. Energex use the general ledger

Requirements (instructions and definitions)	Consistency with requirements
Classification Levels provided in the relevant table in the template. Energex must explain how it has grouped workers into these Classification Levels.	code to extract out only the labour related cost (element code) and standard control services (combination of Responsibility Centre and Activity code) figures. Energex labour categories found in the GL transactions have been mapped to the relevant labour categories required in the CA RIN. For further details please refer to the approach section below.
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.	Cost related Labour hire are separately identified in the table.
Quantities of labour, expenditure, or stand down periods should not be reported multiple times across labour tables However, labour may be split between tables (for example one worker could have half of their time allocated to corporate overheads and half of their time to network overheads).	All figures have been split between the mutually exclusive categories of corporate overheads, network overheads and network direct.
The ASLs for each Classification Level must reflect the average Paid FTEs for each Classification Level over the course of the year.	Energex converted labour hours captured in general ledger system into FTEs which are consistent with average Paid FTEs for each Classification Level over the course of the 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 the approach section.
Stand down periods must be reported against the relevant classification level in the table 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 table.	This has been calculated as per the AER's instructions. For further details please refer to the approach section.

Estimated information was provided for all variables.

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
- General ledger balances ($) of labour hire

The following reports were extracted from the Human Resource Information System (HRIS) or provided by the Energex HR Team:

- Labour category breakdown of labour hire
- 9 days and 10 days fortnightly work arrangement breakdown of internal labour
- HRIS – Monthly Active FTE report
- Stand Down occurrences

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

- Budget – Standard Labour available hours by labour category

Table 22.2 below 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), Budget (Energex Business Performance & Analysis)
Total Labour Cost	Ellipse (GL)
Average Productive Working Hours per ASL	Budget (Energex Business Performance & Analysis)
Stand Down Occurrences per ASL	Ellipse (HR)

Variable	Source
Table 2.11.2 – Extra Labour Descriptor Metrics for Current Year	
Average Productive Work Hours Per ASL - Ordinary Time	Budget (Energex Business Performance & Analysis)
Average Productive Work Hours Hourly Rate Per ASL - Ordinary Time	Ellipse (GL)
Average Productive Work Hours Per ASL - Overtime	Budget (Energex Business Performance & Analysis), Ellipse (GL)
Average Productive Work Hours Hourly Rate Per ASL – Overtime	Ellipse (GL)

22.3 Methodology

Information in the Labour worksheet 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 Approach and assumption

Energex applied the following approach to obtain the required information:

1) Obtained the following General Ledger labour data out of Ellipse:

- Dollars
- Hours
- Ordinary time
- Overtime
- GL code
- Labour category

2) Each GL code was mapped into the categories required in the labour worksheet. The classifications are consistent with Energex's current CAM. The classification of the GL codes can be seen below:

AER CA RIN	Energex
Corporate overhead	Corporate support cost

Network overhead	Metering Customer Call Centre DSM Direct Levies Network operations Solar
Network direct	SCS Direct Opex SCS Direct Capex

3) **ASLs and Total Labour Costs –** Each Energex labour category extracted from Ellipse was then classified into the AER categories. The annual available hours/FTE obtained from budgets (Energex Business Performance & Analysis team) was then used to convert the total labour hours into ASLs.

Energex	AER	Annual Hours/annum
ADMN	SUPPORT STAFF	1,692
APPR	APPRENTICE	1,593
CONT	PROFESSIONAL	1,692
ELEC	SEMI PROFESSIONAL	1,593
EXE1	MANAGER	1,523
EXE2	SENIOR MANAGER	1,611
NEXE	PROFESSIONAL	1,692
PARA	SEMI PROFESSIONAL	1,692
PROF	PROFESSIONAL	1,692
PWKR	UNSKILLED WORKER	1,505
SPEB	MANAGER	1,692
SPVR	SEMI PROFESSIONAL	1,692
SYSO	SEMI PROFESSIONAL	1,692
TECH	SKILLED ELECTRICAL WORKER	1,505
EMT	EXECUTIVE MANAGER	1,611

Please note:

- Executive managers, as specified in the CA RIN, are contained in the Energex labour classification EXE2. These people were manually extracted to comply with the reporting requirements set by the AER. The remainder of EXE2 was then classified as Senior Managers.
- Standard available hours are based on 13/14 budget and adjusted for 9 day fortnightly work arrangement

Once labour costs had been calculated the termination payments for each year were added. These termination payments were obtained from HR data and were added to the labour cost figures for each year.

4) **Average Productive Work Hours per ASL** – Total available hours were then 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:

- Apprentice: 315 hours per year

- All other labour categories: 24 hours per year

5) **Stand down Occurrences per ASL** – 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 for 2009 to 2013.

   The number of stand down occurrences was calculated as the frequency of transactions in each labour category and each year.

   9 hour break transactional data cannot be identified by standard control service, alternative control service and unregulated service as this information is only captured by employee. Energex used total number of occurrences divided by total FTEs as approximation of Stand Down Occurrences per ASL.

   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.

   To accurately report this measure, Energex has adopted the following formula to calculate the figures for Stand Down Occurrences per ASL:

$$\frac{Number\ of\ Stand\ Down\ Occurances}{Energex\ Total\ FTEs}$$

6) Some journals within the GL data were processed without labour categories. Where this occurred, the balance was proportionally allocated to all labour categories (except for the highlighted balances below) within each functional area.

$M	2009	2010	2011	2012	2013
Corporate overhead	0.2	0.1	-0.5	-0.1	0.1
Network overhead	-0.2	2.2	-7.2	-15.3	-17.2
Network Direct	-0.7	-0.3	0.4	9.5	9.4

   Note: The network direct costs of 2012 and 2013 were primarily related to semi-professional and skilled electrical workers. As such the adjustment was not applied to other labour categories.

   Some journals within the GL data were also processed without labour hours. To ensure consistency in the calculation of the Hourly Rate per ASL for Ordinary and Overtime, the journals were excluded from the calculations of Ordinary and Overtime hourly labour rates.

   Redundancy Expenses were also excluded from the calculation of hourly labour rates. These expenses cannot be linked to hours worked per employee and would distort the data if included.

7) **Labour Hire –** Labour hire data has been captured using the GL code element 4920 from 2013. Prior to 2013 however, this GL code was also used for contractors and cannot be relied upon to accurately reflect the labour hire costs.

   To accurately report our labour hire spend, the 2013 actual amount (with the removal of $1.6 million in capital expenditure which was specifically identified as contractor costs) has been used as the best representation of Energex's labour hire spend. This was then de-escalated for years 2009-2012 using the contractor escalation percentage per the Energex budget (which is a function of CPI and the AER determination escalation factors).

   There is no breakdown of labour category for labour hire data. The labour hire figures for Network Overheads and Network Directs for each year were split into the labour categories using a pro-rata methodology, from HR (80% Support Staff/10% Professional/10% Unskilled Worker) based on the known total labour costs in each year. The labour hire dollars calculated were then divided by the productive ordinary time labour rate to obtain hours for each labour category.

   Additionally, labour hire expenses are captured in Ellipse without corresponding labour hire hours. As the purpose of labour hire is to backfill vacant positions, the standard labour rates have been adopted to convert labour hire cost into hours and ASLs.

8) **Table 2.11.2 - Extra Descriptor Metrics For Current Year** – GL transactions were extracted to show both the Ordinary and Overtime components of labour dollars and hours. The average productive work hours per ASL for ordinary hours was extracted directly for each labour category from the Energex budgets.

   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.

   Average productive work hours per ASL for overtime was calculated as the total overtime hours worked per labour category divided by the ASLs calculated for table 2.11.1.

   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.

9) Per the AER's requirements, training cost and FBT should be included in the labour cost. However, due to lack of reliable data, these costs have been excluded. The costs were deemed immaterial for purpose of this report.

22.4 Estimates

Although the Energex GL system captured cost and hours by labour category, there are journals to labour costs were processed without any labour category information. This coupled with definition changes in Energex's labour categories across last 5 years leads to the data being estimated in nature.

22.4.1 Basis for estimates

ASL by labour category

As FTEs are required to split into the functions they performed, the ASLs are calculated based on current available hours per FTE. With changes in mix of employees, operational requirements and work practices from year to year, the calculated FTEs will result in estimated information only.

Cost and hours by labour category

Where there are material journals processed without labour categories (see details in approach section), the balance was proportionally allocated to selected labour categories. This may result in some inconsistencies of hourly rates between corporate overhead, network overhead and network direct.

When journals are processed between GL codes, reclassification of corresponding hours might not be consistently applied. This results in some inconsistencies of hourly rates between labour categories.

Labour Hire

As contactors cost have been included in the labour hire code prior to 12/13, labour hire is estimated for the first four years, based on 2012/13 actual adjusted for information (see details in approach section)

Stand down occurrence

Energex has assumed that the FTE data in relation to 9 hour break payments equates to number of stand down occurrences for ASLs.

22.5 Explanatory notes

ASL movement between financial years 2009/10 to 2010/12:

- Senior manager/Manager:
    - In 2013 Energex standard labour costing classified EXE2 into a different labour cost category resulting in higher senior ASLs per current mapping. It also explains the corresponding reduction in manager in 2013.

- Managers and Semi Professional:
  - In 2012, the increase is due to extra Program of Work initiatives i.e. Job ready, program governance, network operations, projects and works

Termination Payments

- In the 2012 and 2013 financial year there were significant termination payments incurred by Energex (approximately $9 million in 2012 and $51 million in 2013). This has the effect of increasing the labour rates for those years.

Reporting where relevant labour classifications are unavailable:

- In some instances, Energex's mapping of labour categories to AER classifications produces results which are unable to be populated against the relevant classifications. These instances exist for Network Overheads and Network Directs, which have been populated into the Master templates as detailed below.

- Within Network Overheads, figures reported for Intern/Junior Staff/Apprentice represent data that would otherwise have been reported as:
  - Skilled Electrical Workers
  - Skilled Non-Electrical Workers
  - Apprentices (Intern/Junior Staff/Apprentice previously only reported Apprentices)

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

- These classifications have been 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.

Labour Hire

- Labour hire expenses are captured in Ellipse without corresponding labour hire hours. As the purpose of labour hire is to backfill vacant positions, the standard labour rates have been adopted to convert labour hire cost into hours and ASLs.

22.6 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice has not materially changed in nature.

23 BoP 2.12-1 – Input tables – Overheads

The AER requires Energex to provide the following variables relating to overheads in worksheet 2.12 Input Tables:

- **Network overheads**
- **Corporate overheads**

Each variable is to be disaggregated into:

- **Direct material costs**
- **Direct labour costs**
- **Contract costs**
- **Other costs**
- **Related party contract cost**
- **Related party contract margin**

Information provided below covers the disaggregation for the listed variables for all items excluding related party costs. A separate Basis of Preparation has been prepared for the disaggregation of related costs for all variables.

Estimated information was provided for all variables for 2009 and 2010.

Actual information was provided for all variables for 2011 to 2013.

23.1 Consistency with CA RIN Requirements

Table 23.1 below 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 CA 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.	Refer above.

Direct materials costs are attributable to a specific asset or service, cost centre, or work order, and exclude materials provided under external-party contracts. Includes: • the cost of scrap • normally anticipated defective units that occur in the ordinary course of the production process • routine quality assurance samples that are tested to destruction • the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: • Labour hire; and • Ordinary time earnings; and • Other earnings, on-costs and taxes; and • Superannuation.	Refer above.
Contract A legally binding contract.	Refer above.

Actual information sourced from Energex's corporate systems was used to provide the variables in this table. Where adjustments were made to reflect regulatory reporting requirements, a proportional allocation based on the total dollar value was applied to the respective cost categories.

23.2 Sources

Information for overheads has been sourced directly from the annual regulatory accounts, or from general ledger reports which support the figures reported in the annual regulatory accounts.

Table 23.2 below 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.

23.3 Methodology

Energex has sourced the required information from the annual regulatory accounts and/or supporting general ledger reports. It has then categorised the information based on the relevant cost elements.

23.3.1 Assumptions

- Information is based on the audited annual regulatory accounts and/or supporting ledger reports.
- Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contract costs, consistent with section 13 of the Explanatory Statement to the CA RIN. While in some instances this has resulted in negative figures being reported for contract costs, the combined total of contract and related party contract costs is positive.

23.3.2 Approach

1) For years when information wasn't able to be sourced directly from the annual regulatory accounts, Energex has mapped the detail from general ledger reports to the required categories.

2) 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 6.

3) Separate mapping to Network Overheads and Corporate Overheads is in accordance with the mapping applied for Template 2.10.

4) For 2009 and 2010, balances were adjusted to be consistent with those reported in Template 2.10 which reflect the figures in the annual regulatory accounts each year.

5) For the period 2011 to 2013, a proportional allocation method was applied to facilitate the assignment of regulatory reporting adjustments to the respective cost categories. This was due to the fact that 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.

6) Information was separately sourced for related party costs and other (material, labour, contractor and other) costs. Upon consolidation, the related party costs have been deducted from the contractor costs, consistent with section 23.3.1 above.

23.4 Estimates

Information for 2009 and 2010 is regarded as Estimated due to the adjustments required to balance to the annual regulatory accounts.

23.4.1 Justification for estimates

Template 2.12 needs to balance to Template 2.10 and both need to reconcile to the annual regulatory accounts. To comply with these requirements, all variables were adjusted to achieve consistency and have been reported as Estimates.

23.4.2 Basis for estimates

All variables were proportionally adjusted to reconcile to achieve presentation consistent with the annual regulatory accounts.

23.5 Explanatory notes

- The significant increase in Direct Material Cost for Network Overheads from 2011 is the result of Solar PV FiT payments. Refer to Template 2.10 for more information.
- The increase in Direct Labour Cost for Corporate Overheads from 2012 is the result of termination payments. Refer to Corporate Restructuring costs in Template 2.10 for more information.
- The increase in Contractor Cost for Corporate Overheads over the five year period is the result of increasing IT and Communications costs. Refer to Template 2.10 for more information.
- The decrease in Other Cost for Corporate Overheads from 2011 is reflective of the new CAM applied from the start of the 2011 regulatory control period. Costs for 2009 and 2010 included depreciation on the associated non-system assets, which has been reported as Other Cost in this template. Refer to the Basis of Preparation for Template 2.10 for more information.

23.6 Accounting policies

Refer to section 1.1.6 of the Basis of Preparation for table 2.10 – Overheads for details related to Energex's change of CAM from 2011 and the new regulatory control period.

24 BoP 2.12-2 – Input tables – Related Party Costs

The AER requires Energex to provide the following categories relating to related party contract cost:

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

These categories are a part of worksheet “2.12 Input tables”.

Actual information was provided for all categories listed above for 2009, 2012 and 2013.

Estimated information was provided for 2010 and 2011.

24.1 Consistency with CA RIN Requirements

Table 24.1 below 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 that significantly influenced, influences or is expected to influence Energex; or · was, is or is expected to be significantly influenced by the same	Energex has reported all related party costs reported in the regulatory accounts in accordance with the categories specified in this CA RIN table where applicable, except for the following items: 1) Powerlink Transmission Use of

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.	System cost (TUOS) was reported in the annual regulatory accounts in 2011 as related party opex but has since been excluded in line with the AER requirements (it is a pass-through and does not form part of opex, which the related party disclosures relate to). It is not reported in this CA RIN table for any of the five years for consistency and comparability across the five years. 2) Only related party costs that had been assessed to be material were reported in the annual regulatory accounts for 2013. Prior to this, a materiality threshold did not apply and relevant Ergon Energy, Powerlink and Energy Impact Pty Ltd's costs were reported as related party costs. To enable comparison across the five years, relevant Ergon, Powerlink and Energy Impact Pty Ltd's costs have been reported for all years.
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	All Energex's related party transactions are at cost so

costs under a *Related Party Contract* with Energex. This profit may include margins, management fees or incentive payments.	there is no margin.

Actual information was provided for all categories in this table for 2009, 2012 and 2013.

Estimated information was provided for 2010 and 2011.

24.2 Sources

Related party cost information is either from the annual regulatory accounts or from transaction listings from Ellipse which support the amounts reported in the annual regulatory accounts.

Table 24.2 below sets out the sources from which Energex obtained the required information.

Table 24.2: Information sources

Category	Source
Network Overheads	Annual regulatory accounts and/or supporting workings for Energy Impact costs, relevant Ergon costs and relevant Powerlink costs
Corporate overheads	Annual regulatory accounts and/or supporting workpapers for SPARQ Opex, relevant Ergon costs and relevant Powerlink costs.
Non-Network Expenditure – IT & Communications	SPARQ Capex and Opex from the annual regulatory

	accounts.
Routine Maintenance, Non-Routine Maintenance, , Augmentation, Connections, Emergency Response, Public Lighting, Quoted Services, Replacement, Non-Network Expenditure – Buildings and Property	Annual regulatory accounts and/or supporting workpapers for relevant Ergon and Powerlink costs for the related party reporting .

24.3 Methodology

Energex sourced the required information from the annual regulatory accounts and/or supporting transaction listings and categorised the information as required in the AER CA RIN table based on the nature of the transactions.

24.3.1 Assumptions

All information for 2009, 2012 and 2013 is based on the audited annual regulatory accounts and/or supporting workpapers. No estimates or assumptions were applied.

For 2010 and 2011, assumptions were made and estimates used in separating SPARQ costs into non-network IT&C expenditure and other categories.

24.3.2 Approach

Energex categorised the relevant information from the regulatory accounts and/or supporting workpapers as required in the AER CA RIN table. Where applicable, detailed transaction listings supporting the regulatory accounts workpapers were obtained. The transactions were categorised into the CA RIN categories (routine maintenance, non routine maintenance, replacement and augmentation, etc.) based on their general ledger activity codes. Further classification into sub-categories for the relevant items was conducted by a senior engineer based on the detailed descriptions of the purchase orders and/or invoices.

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

24.4 Estimates

Based on the supporting workpapers for the related party reporting in the annual regulatory accounts for 2011, costs related to categories other than non-network IT&C (for example Emergency Response, Corporate Overheads and Network Overheads) were identified based on activity codes and responsibility centres. The 2010 costs that were related to categories other than non-network IT&C were identified by comparing the total opex in the related party reporting for the CA RIN to the amount reported for non-network IT&C in Table 2.12. The difference for 2010 as a result of this comparison has been proportionally allocated to the categories identified in the 2011 workpapers.

24.5 Explanatory notes

1) Powerlink is a related party to Energex by definition, as both companies are owned by the Queensland State Government. Energex has transactions with Powerlink for:
    a. TUOS (Transmission Use of System or Designated Pricing Proposal Charges) which are a pass-through and are neither opex or capex; and
    b. Other opex and capex transactions.

    TUOS is not reported as a related party transaction in the annual regulatory accounts from 2012 as the annual regulatory accounts only require related party costs for opex and capex.

    The CA RIN requirement is to populate the Input Tables for SCS and ACS, as stated in the AER's Issues Register. As TUOS is neither SCS or ACS, it is not captured in the CA RIN.

2) Total related party costs reported in this table for each year were reconciled to the total from the annual regulatory accounts. The differences are explained in table below:

Year	CA RIN Table 2.12 related party cost total ('$000)	Related party cost total from the annual regulatory accounts ('$000)	Variance ('$000)	Explanations for the variance
2009	114,741	61,853	52,888	SPARQ opex is in both Corporate Overheads and Non Network Expenditure - IT&C in this CA RIN table
2010	148,074	81,781	66,293	SPARQ opex is in both Corporate Overheads and Non Network Expenditure - IT&C in this CA RIN table.
2011	185,276	446,367	(261,091)	- **$81,151k** SPARQ opex is included in both Corporate Overheads and Non-Network Expenditure - ITC in this CA RIN table; - **($342,242k)** Powerlink TUOS is

				included in related party opex in the annual regulatory accounts but not included in this CA RIN table for consistency and comparability with other years.
2012	211,613	114,410	97,203	SPARQ opex is in both Corporate Overheads and Non Network Expenditure - IT&C in this CA RIN table.
2013	210,633	99,261	111,372	-**$2.5k** SPARQ costs are in both Emergency Response and Non Network Expenditure - IT&C in this CA RIN table; - **$94,856k** SPARQ operating costs are both in Corporate Overheads and Non Network Expenditure - IT&C in this CA RIN table; - **$1,166k** Energy Impact cost, **$7,096k** Ergon Capex and Opex, and **$8,251k** Powerlink Capex and Opex were not reported in the 2013 regulatory accounts as they didn't meet the materiality threshold as stated in the Annual RIN requirements while in 2011 and 2012 all their costs were reported regardless of materiality in line with the Annual RIN requirements prior to 2013. They are therefore reported in this CA RIN table for 2013 as well for consistency.

SPARQ expenditure is reported under both Non-network IT & Communication Expenditure and Corporate Overheads due to the definitions of those items within the CA RIN.

24.6 Accounting policies

There have been no accounting policy changes that are relevant to this CA RIN template.

25 BoP 2.12-3 – Input tables – Fee Based and Quoted Services

The AER requires Energex to provide the following variables in worksheet 2.12 Input tables:

- **Fee Based Services**
- **Quoted Services**

Each variable is to be disaggregated into the following cost categories:

- **Direct material cost**
- **Direct labour cost**
- **Contract cost**
- **Other cost**
- **Related party contract cost**
- **Related party contract margin**

Information provided below covers the disaggregation for the listed variables for all cost categories excluding related party cost and margin. A separate Basis of Preparation has been prepared for the disaggregation of related party cost for all variables.

Actual information was provided for both variables listed above.

25.1 Consistency with CA RIN Requirements

Table 25.1 below 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
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 CA RIN table 2.12, which balance to the annual 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	Refer above.

centre, or work order, and exclude materials provided under external-party contracts. Includes: • the cost of scrap • normally anticipated defective units that occur in the ordinary course of the production process • routine quality assurance samples that are tested to destruction • the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: • Labour hire; and • Ordinary time earnings; and • Other earnings, on-costs and taxes; and • Superannuation.	Refer above.
Contract A legally binding contract.	Refer above.

Actual information was sourced from Energex's annual regulatory accounts workpapers and/or supporting general ledger reports to provide the variables in this table.

25.2 Sources

Information for Table 2.12 Input tables has been sourced directly from the annual regulatory accounts workpapers, or from general ledger reports which support the amounts reported in the annual regulatory accounts.

Table 25.2 below sets out the sources from which Energex obtained the required information.

Table 25.2: Information sources

Variable	Source
Fee Based Services and Quoted Services– 2009 & 2010	Annual regulatory accounts work papers
Fee Based Services and Quoted Services – 2011 to 2013	General ledger reports

25.3 Methodology

Energex sourced the required information from the annual regulatory accounts workpapers and/or supporting general ledger reports. It then categorised the information based on the relevant cost elements.

25.3.1 Assumptions

- Information is based on the audited annual regulatory accounts workpapers and/or supporting ledger reports.
- Energex has consistently reported direct costs throughout the CA RIN. This means that overhead costs have been excluded from the Fee-Based and Quoted Services figures reported in Table 2.12 Input tables.
- Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contract costs, consistent with section 13 of the Explanatory Statement to the CA RIN. While in some instances this has resulted in negative figures being reported for contract costs, the combined total of contract and related party contract costs is positive.

25.3.2 Approach

- Information was obtained by cost element from the annual regulatory accounts workpapers and/or supporting general ledger reports.
- 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 6.

- Information was separately sourced for related party costs and other costs (material, labour, contractor and other). The related party costs have been excluded from the contractor costs, consistent with section 25.3.1 above.
- 2009 and 2010
  - Alternative Control-equivalent services for the previous Determination period (classified as Excluded Distribution Services from 2008 to 2010) were not further sub-classified as Fee-Based or Quoted Services in the annual regulatory accounts. Energex determined this sub-classification for the CA RIN based on a review of the workpapers for the regulatory accounts for the relevant years. In most cases:
    - Business-to-Business (B2B) services provided to retailers have been classified as Fee Based; and
    - Price on Application (POA) services and Infrastructure Projects (conducted under State Government infrastructure development initiatives, which are similar in nature to Rearrangement of Network Assets) have been classified as Quoted Services.
  - Exceptions relate to services which can be both Fee-Based and Quoted, dependant on the nature. For example, simple services for Temporary Connections are Fee-Based whereas complex services are Quoted Services.
  - Amounts reconcile to those reported in the annual regulatory accounts excluding overheads.
- 2011 to 2013
  - 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 workpapers and/or supporting documents.

25.4 Estimates

No estimates have been applied in this table.

25.5 Explanatory notes

Not Applicable

26 BoP 2.12-4 – Input Tables – Non-Network Property and ICT

The AER requires Energex to provide the following information relating to table 2.12 – Input Tables:

Direct Materials, Direct Labour, Contract and Other Costs.

- **Non-Network – IT and Communications**
- **Non-Network – Buildings and Property**
- **Non-Network – Other**

These variables are a part of worksheet 2.12 – Input Tables

Actual information was provided for all variables.

26.1 Consistency with CA RIN Requirements

Table 26.1 below 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
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 CA RIN table 2.12.
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	Refer above.

- routine quality assurance samples that are tested to destruction - the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: - Labour hire; and - Ordinary time earnings; and - Other earnings, on-costs and taxes; and - Superannuation.	Refer above.
Contract A legally binding contract.	Refer above.

Actual information was provided for all variables.

26.2 Sources

Table 26.2 below sets out the sources from which Energex obtained the required information.

Table 26.2: Information sources

Variable	Source
Non-Network Expenditure (Direct Materials, Direct Labour, Contract, Other and Related Party costs as well as Related Party Margins)	
IT and Communications	SPARQ information based on invoices issued to Energex; Accounting Entry Report per Ellipse; Profit and Loss for SPARQ 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 1025 (2310 for 08/09) account 4940 Mapping table for allocation of cost element to the Input Tables categories (Appendix 6). Provided by Regulatory Accounting division.
Buildings and Property	Profit and Loss Report by RC 2510 & 3600 Accounting Entry Report by Activity 62010 and RC 2510 for Non-Regulated activities Regulatory Accounts Mapping table for allocation of cost element to the Input Tables categories (Appendix 6). Provided by Regulatory Accounting divison.
Other	Fixed Asset Register extract for Newstead project Accounting Entry Report by RC 2510 for CapexAccounting Entry Report by RC 2510 for Capex Mapping table for allocation of cost element to the Input Tables categories (Appendix 6). Provided by Regulatory Accounting divison.

26.3 Methodology

The figures in table 2.12 are based on the figures generated for worksheet 2.6 – Non-network. 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 6.

26.3.1 Assumptions

- Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contract costs, consistent with section 13 of the Explanatory Statement to the CA RIN. While in some instances this has resulted in negative figures being reported for contract costs, the combined total of contract and related party contract costs is positive.

26.3.2 Approach

Energex applied the following approach to obtain the required information.

IT and Communications

The IT and Communications figure was calculated as the sum of the following items from worksheet 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):

1) Client Device Expenditure Opex ($’000) – The expenditure from SPARQ to Energex is allocated to “Contractor Costs” as per the conversion table found in Appendix 6.

2) Client Device Expenditure Capex ($’000) – The identified client devices were pivoted by each cost element and allocated as per conversion table found in Appendix 6. The pivot table showed some client devices being allocated to “Contractor Costs”. These costs were related to the purchase of ToughBooks however they were purchased through SPARQ. These costs were reallocated to “Direct Materials Costs” as this reflects the correct category of spend.

3) Recurrent Expenditure Opex ($’000) – These items have been reconciled to the SPARQ accounts and allocated based as per the conversion table provided in Appendix 6. 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.

4) Recurrent Expenditure Capex ($’000) –

   - Recurrent Capex 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 pivoted by element and allocated as per conversion table provided in Appendix 6.

   - The percentage split between “Direct Material Costs”, “Direct Labour Costs”, “Contractor Costs” and “Other Costs” by financial year was obtained from the mapping of all ICT capex data (less client devices) using the table in Appendix 6. These percentages were then applied to the recurrent expenditure identified in 2.6. This was to ensure that the figures reconciled back to the regulatory accounts. The effect of the percentage allocation is immaterial to the total figures.

5) Non-recurrent Opex ($'000) – The expenditure was allocated to "Contractor Costs" as per conversion table provided in Appendix 6.

6) Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contractor costs.

Buildings and Property

The Buildings and Property figures were calculated as the sum of the following items from worksheet 2.6 broken down into each input table category (for further details of the methodology for figures stated in 2.6 please refer to the relevant basis of preparation):

1) Building & Property Opex – The expenditure from 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 6. Non-regulated and network expenditure was not included in the calculations.

2) Buildings & Property Capex – The figure contained data extracted directly for Buildings and Property from the accounting entry reports as well as an allocation of fixtures and fittings from the Newstead project.

    - The Buildings and Property Capex figure in template 2.6 (less that for Newstead fixtures and fittings) was taken and broken up into the required categories. This was done by firstly calculating the proportion of Direct Materials, Direct Labour, Contract and Other Costs in each year based on the totals found in the accounting entry reports. These percentages were then multiplied by the figures found in 2.6.

      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 and exclude the amounts separated into other expenditure for furniture.

    - The Newstead Property & Building Expenditure Capex ($'000) figures were then added to the numbers calculated above. The percentages were identified for "Direct Material Costs", "Direct Labour Costs", "Contractor Costs" and "Other Costs" by element by financial year for the Newstead project as per conversion table provided in Appendix 6. The percentages were applied against the fixtures and fittings portion of the Newstead project (as identified in the Basis of Preparation for worksheet 2.6). The figure calculated for Newstead fixtures was then added to the Buildings and Property Capex figure.

3) Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contractor costs.

Other Expenditure

The other expenditure figures were calculated as the sum of the items below. The first two items relate to the “Other – Office Furniture” in worksheet 2.6. The third item relates to the “Other – Plant and Equipment” figure in worksheet 2.6.

1) Newstead Other Expenditure Capex ($’000) – The furniture portion of the Newstead project was calculated in basis of preparation 2.6. These figures were then split between “Direct Material Costs”, “Direct Labour Costs”, “Contractor Costs” and “Other Costs” using the same percentages used above in the Newsteaed fixtures and fittings portion of Buildings and Property Capex. The value calculated for “Other” was allocated to the “Other” expenditure category required in worksheet 2.12.

2) Non-Newstead Other Expenditure Capex ($’000) – The percentage split between “Direct Material Costs”, “Direct Labour Costs”, “Contractor Costs” and “Other Costs” was identified by element by financial year based on total furniture capex from the accounting entry reports and using the conversion table provided in Appendix 6. The percentages were applied to the Other Furniture (Non-Newstead) Expenditure identified in each financial year.

3) Other Plant & Equipment Expenditure Capex ($’000) – The expenditure relating to Manual Handling Systems and Generator were allocated to “Other Expenditure - Contractor Costs” as this expenditure was paid through contractors undertaking the Geebung development.

The figures calculated above were then added to the “Other Expenditure” calculated in the Motor Vehicles basis of preparation to give a final figure for Non-network – Other Expenditure across each category and year. For the calculation of Motor Vehicle – Other expenditure please refer to the basis of preparation for Input Tables – Motor Vehicles.

26.4 Explanatory notes

For detailed explanatory notes please refer to the bases of preparation for table 2.6 – Non-network (IT and Communication and Property respectively)

27 BoP 2.12-5 – Input Tables – Non-Network Fleet, Tools and Equipment

The AER requires Energex to provide the following information relating to table 2.12 – Input Tables:

Direct Materials, Direct Labour, Contract and Other Costs for the following variables

- **Non-Network – Motor Vehicles**

These variables are a part of worksheet 2.12 – Input Tables

Actual information was provided for all variables.

27.1 Consistency with CA RIN Requirements

Table 27.1 below 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
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 CA RIN table 2.12.
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	Refer above.

Requirements (instructions and definitions)	Consistency with requirements
• routine quality assurance samples that are tested to destruction • the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: • Labour hire; and • Ordinary time earnings; and • Other earnings, on-costs and taxes; and • Superannuation.	Refer above.
Contract A legally binding contract.	Refer above.

Actual information was provided for all variables, some information was provided by our Fleet Management company SG Fleet Australia. This information was based on invoice payments per motor vehicle category.

27.2 Sources

Table 27.2 below sets out the sources from which Energex obtained the required information. Sources are as per the sources in the basis of preparation for worksheet 2.6 Non-Network – Fleet, Tools and Equipment.

Table 27.2: Information sources

Variable	Source
Non-Network Expenditure - Motor Vehicles & Other 2009-13	• 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

Variable	Source
	Australia Pty Limited) • Previous Annual Capex RIN 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 6). Provided by Regulatory Accounting division.

27.3 Methodology

The figures calculated for Non-network Motor Vehicles expenditure were calculated using the expenditure figures calculated for worksheet 2.6. These figures have then been split using the mapping table found in Appendix 6.

27.3.1 Approach

Motor Vehicles Expenditure

1) Figures for motor vehicles expenditure was calculated for worksheet 2.6. For details of the calculation please refer to the basis of preparation for 2.6.

2) 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 6 to classify the motor vehicles expenses into the categories required in worksheet 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 for each year.

3) Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contractor costs.

Other Expenditure

1) All “Other” expenditure reported for Motor Vehicles in worksheet 2.6 was classified into Direct Materials, Direct Labour, Contract and Other Costs using the cost element mapping table found in Appendix 6. Once classified the following variables were added together to give a total for other expenditure:

   - Other Non-Network Expenditure Fleet Tools & Equipment

- Other Motor Vehicles - Mobile Generators
- Other Motor Vehicles - Trailers
- Other - Tools & Equipment
- Other

2) The “Other” expenditure total figure was then calculated as the sum of the “Other” items for both Motor Vehicles and Property.

27.4 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. This has occurred throughout the past five financial years, and is very evident when there is expenditure and no physical in that year ie: 2012/13 Network Expenditure HCV – Elevated Work Platforms.

27.5 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice, has not materially changed in nature.

28 BoP 2.12-6 – Input Tables – Remaining Metrics

The AER requires Energex to provide the following information relating to Input Tables:

Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs

- **Vegetation Management**
- **Routine Maintenance**
- **Non-routine Maintenance**
- **Augmentation**
- **Connections**
- **Emergency Response**
- **Public Lighting**
- **Metering**
- **Replacement**

These variables are a part of worksheet 2.12 – Input Tables.

Actual information was provided for.

- **Emergency Response**

Estimated information was provided for the following figures

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

28.1 Consistency with CA RIN Requirements

Table 28.1below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 28.1: 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.	Energex has reported all direct costs in accordance with the categories specified in CA RIN table

Excludes any allocated overhead.	2.12, which balance to the annual 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.

Actual information was provided for.

- Emergency Response

Estimated information was provided for the following figures

- Routine Maintenance
- Non-routine Maintenance

- Vegetation Management
- Augmentation
- Connections
- Public Lighting
- Metering
- Replacement

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
Vegetation Management	Corvu and MER ECA90W
Routine Maintenance	SQL query that extracted data from the Ellipse GL tables Corvu POW 302 Reports
Non-routine Maintenance	SQL query that extracted data from the Ellipse GL tables Corvu POW 302 Reports
Augmentation	EPM
Connections	Corvu Fin027, Ellipse (MER ECAA01)
Emergency Response	EPM POW005 Transaction Report
Public Lighting	MER ECA90W, Corvu
Metering	Peace, Ellipse, ACS Quote Mode, Business Objects Reports

Replacement	EPM

28.3 Methodology

28.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- It is assumed that the “Major Storms” category within the Emergency Response section relates to the total costs reported in section B of worksheet 2.9.

- Information was separately sourced for related party costs. Upon consolidation of the Input Tables worksheet, the related party costs have been deducted from the contract costs, consistent with section 13 of the Explanatory Statement to the CA RIN. While in some instances this has resulted in negative figures being reported for contract costs, the combined total of contract and related party contract costs is positive.

28.3.2 Approach

Energex applied the following approach to obtain the required information:

Vegetation Management

1) The vegetation management costs were developed by zone within worksheet 2.7 – Vegetation Management. For full details of the development of the vegetation management figures please refer to the relevant basis of preparation.

2) 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 6 to split the total costs for each region into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs per year.

Routine and Non-routine Maintenance

1) Routine and non-routine maintenance figures were developed from the Energex Network Asset Management Plan (NAMP) codes within template 2.8. For full details please refer to the basis of preparation for maintenance cost metrics.

2) The maintenance costs were extracted with Energex cost elements when being developed for worksheet 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 6. The cost for each year was then summated to obtain the routine and non-routine maintenance figures in the Input Tables worksheet.

3) Certain costs reported in the under “Zone Substation Inspection” were identified to relate to “Distribution Asset Inspection”. The costs to be redistributed were determined by firstly analysing the amount within each standard job description under the applicable NAMP line for one year. The analysis of the standard job descriptions then generated a percentage that related to “Distribution Asset Inspection”. This percentage within “Zone Substation Inspection” was then reallocated to “Distribution Asset Inspection” for each year.

Augmentation

1) Figures for augmentation expenditure broken down into the required categories (Substations, Feeders, Lines etc.) were calculated for worksheet 2.3 – Augex in 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 table 2.3.4.

2) 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 6 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 table 2.3.4 to produce the figures for the input tables worksheet.

Connections

1) The figures for connections have been apportioned to labour, material, contract and other cost categories based on each respective years expenditure 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 over the 5 year period 2008-09 to 2012-13 financial years. As such the percentages were used rather than the actual figures to ensure the total for connections expenditure balanced.

Emergency Response

1) The figures for “Major Storms” in worksheet 2.12 have been calculated using the figures found in section B of worksheet 2.9 – Emergency Response. These numbers in worksheet 2.9 have been 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 6.

2) The figures for “Major Event Days” in worksheet 2.12 have been calculated using the figures found in section C of worksheet 2.9 Emergency Response. The figures in worksheet 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 6.

Public Lighting

1) The figures for public lighting costs in the input tables worksheet were based on the calculations done for the total cost figures in table 4.1.2. A report was run from Mincom Ellipse that detailed the project expenditure against the following financial activity codes:

   - C2560 – CWDA Public Lighting
   - C3560 – Street Lighting
   - C2545 – Pole Replacement
   - 41600 – Street Lighting

   These three activity codes incorporate all figures for streetlight installation, replacement and maintenance. This report also broke the project expenditure into cost elements.

2) The cost elements were grouped using the mapping table in Appendix 6 to then generate the total public lighting figures for Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost.

Metering

1) The metering values in worksheet 2.12 have been calculated using the expenditure figures stated in table 4.2.2. For the full details of the calculation of each of these figures please refer to the basis of preparation for worksheet 4.2.

2) The expenditure figures for each year have been classified into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs based upon the following logic:

Metering Expenditure Service Subcategory	Classification Methodology
Meter Purchase	Figures in 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 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter testing were 100% Contractor Costs.
Meter Investigation	Figures in 4.2.2 were calculated by using a build-up of materials,

	labour, contractor and other costs. The values for meter investigation were 100% Direct Labour Costs.
Scheduled Meter Reading	Scheduled meter reading in Energex is performed only by contractors and has been classified as 100% Contractor Costs. All data in 4.2.2 was derived from invoices paid to contractors.
Special Meter Reading	Special meter reading in Energex is performed only by contractors and has been classified as 100% Contractor Costs. All data in 4.2.2 was derived from invoices paid to contractors.
New Meter Installation	Figures in 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for new meter installation were distributed between Direct Labour and Direct Materials Costs based on the workings for 4.2.2.
Meter Replacement	Figures in 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter replacements were distributed between Direct Labour, Direct Materials and Contractor Costs based on the workings for 4.2.2.
Meter Maintenance	Figures in 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter maintenance were distributed 100% to Direct Labour Costs based on these workings.
Other Metering	Figures in 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for other metering were 100% allocated Direct Material Costs.

3) Each service subcategory figure per year for Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs was then summated to give the figures reported in the input tables worksheet for each year.

Replacement

1) Figures for replacement expenditure broken down into the required categories (Poles, Cables, Transformers etc.) were calculated for worksheet 2.2 – Repex in 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 table 2.2.1.

2) 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 6 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 table 2.2.1 to produce the figures for the input tables worksheet.

28.4 Estimates

28.4.1 Justification for estimates

The figures reported in the following sections are considered estimated as they relied upon estimated data in other worksheets:

- Routine Maintenance
- Non-routine Maintenance
- Vegetation Management
- Augmentation
- Public Lighting
- Metering
- Replacement

28.4.2 Basis for estimates

For details of the estimates please refer to the respective basis of preparation for each worksheet.

28.5 Explanatory notes

Explanatory notes for negative balances seen in the Input table figures are as follows:

Routine Maintenance: DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE – Materials Costs 2010/11

- The negative balance shown is due to the reversal of materials issued in prior years. The reversal of these materials resulted in a credit balance in the 2010/11 year.

Non-Routine Maintenance: POLE INSPECTION AND TREATMENT – Contract Costs 2012/13

- The negative balance shown is due to the reversal of provisions relating to mitti cable inspection costs. These provisions were raised in a prior year and then deemed to be not required and subsequently reversed.

Non-Routine Maintenance: POLE INSPECTION AND TREATMENT – Other Costs 2012/13

- The negative balance shown is due to the reversal of provisions relating to mitti cable advertising costs. These provisions were raised in a prior year and then deemed to be not required and subsequently reversed.

Replacement – Transformers – Other Costs 08/09 and 09/10

- The negative balances in the replacement figures for transformers in 08/09 and 09/10 are due to returns of transformers. These transformers were expensed in prior years (pre 2008/09) and then returned in the reported years resulting in credit balances.

APPENDICES

Appendix 1 – Mapping Table

Mapping Table – CA RIN Categories vs Annual Regulatory Accounts Categories (by Reason)

Service Classification	AER Category Analysis RIN Categories	AER Capital Activity - Annual Reg Accounts
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 2 – Detail of Balancing Items

Table 2.1.1 - Standard control services capex

Balancing item is made up of:	Actual ($000s nominal)				
	2009	2010	2011	2012	2013
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			-7,391.7	-8,507.8	-8,490.2
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			-12,902.4	-14,576.2	-12,208.6
Total balancing item per above	**0.0**	**0.0**	**-20,294.1**	**-23,084.0**	**-20,698.8**

Table 2.1.2 - Standard control services opex by category

Balancing item is made up of:	Actual ($000s nominal)				
	2009	2010	2011	2012	2013
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			-229.0	-304.3	-515.4
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			-6,288.0	-5,951.6	-6,552.3
Non-network costs - included in Template 2.6 Non-network as opex and Template 2.10 Overheads	-117,655.6	-129,557.5	-154,621.8	-172,018.0	-181,560.7
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	-6,135.6	-7,255.0	-6,348.4	-7,448.2	-7,679.2
Total balancing item per above	**-123,791.2**	**-136,812.5**	**-167,487.3**	**-185,722.2**	**-196,307.6**

Table 2.1.3 - Alternative control services capex

Balancing item is made up of:	Actual ($000s nominal)				
	2009	2010	2011	2012	2013
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			-54.8	-228.2	-279.8
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			-128.9	-276.9	-230.9
Large Customer Connections reported in 2.5 Connections and 4.3 Quoted Services			-734.1	-6,000.4	-6,728.6
Total balancing item per above	**0.0**	**0.0**	**-917.8**	**-6,505.6**	**-7,239.2**

Table 2.1.4 - Alternative control services opex

Balancing item is made up of:	Actual ($000s nominal)				
	2009	2010	2011	2012	2013
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			-239.4	-154.3	-94.4
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			-952.5	-908.1	-480.2
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	-4,659.7	-5,365.3	-4,901.9	-5,034.5	-4,835.2
Total balancing item per above	**-4,659.7**	**-5,365.3**	**-6,093.8**	**-6,096.9**	**-5,409.8**

For further details of the balancing items please refer to the attached spreadsheet.

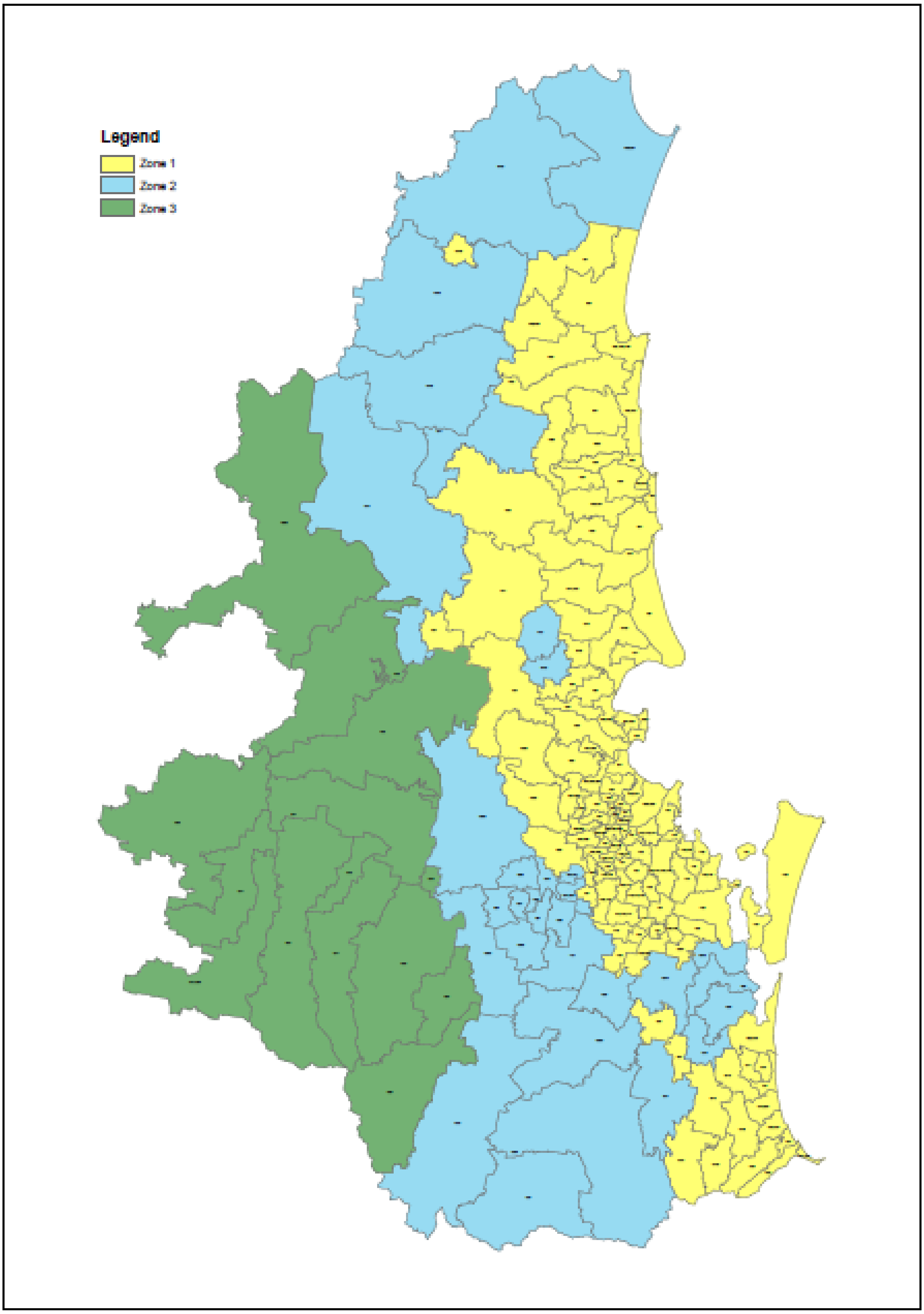
Appendix 3 – Statutory to Regulatory Reconciliation

For further details of the statutory to regulatory reconciliation please refer to the attached spreadsheet.

	2009			2010			2011			2012			2013		
	CAPEX	OPEX	TOTAL	CAPEX	OPEX	TOTAL	CAPEX	OPEX	TOTAL	CAPEX	OPEX	TOTAL	CAPEX	OPEX	TOTAL
	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
Template 2.1 Summary Numbers															
SCS	793.1	310.0	1,103.1	951.5	314.6	1,266.0	925.7	353.6	1,279.4	925.7	442.4	1,368.1	869.8	572.4	1,442.2
ACS	-	22.9	22.9	-	22.7	22.7	5.5	34.4	40.0	11.1	27.3	38.4	14.2	25.1	39.3
TOTAL from Template 2.1	793.1	332.8	1,126.0	951.5	337.3	1,288.7	931.3	388.1	1,319.3	936.8	469.7	1,406.5	884.0	597.5	1,481.5
Adjusted for:															
• Replacement expenditure not included in Template 2.2 Repex as there was no basis on which to allocate expenditure to categories, but is included in the regulatory accounting numbers	7.1	-	7.1	3.2	-	3.2	15.4	-	15.4	9.1	-	9.1	12.7	0	12.7
• 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	6.3	-	6.3	4.0	-	4.0	4.0	-	4.0	2.8	-	2.8	-6.3	0	-6.3
• Demand Side Management expenditure excluded from Template 2.3 Augex but included in the regulatory accounting numbers	0.7	-	0.7	2.2	-	2.2	2.3	-	2.3	-0.2	-	-0.2	2.3	0	2.3
• 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	12.6	-	12.6	35.1	-	35.1	14.9	-	14.9	15.4	-	15.4	16.1	0	16.1
• Gifted assets excluded from Templates 2.5 Connections but included in the regulatory accounting numbers	13.7	-	13.7	15.3	-	15.3	21.1	-	21.1	24.2	-	24.2	23.3	0	23.3
• 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	-	3.8	3.8	-	0.3	0.3	-	0.2	0.2	-	0.2	0.2	-	0.20	0.2
• Gifted assets excluded from Templates 4.1 Public Lighting but included in the regulatory accounting numbers	5.1	-	5.1	3.4	-	3.4	4.3	-	4.3	6.3	-	6.3	7.8	0	7.8
• 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	3.2	-	3.2	4.0	-	4.0	3.4	-	3.4	3.3	-	3.3	2.1	0	2.1
• Inventory items included in Template 4.2 Metering that are excluded from the regulatory accounting numbers for capex and opex	-7.3	-	-7.3	-7.2	-	-7.2	-11.2	-	-11.2	-10.7	-	-10.7	-9.3	0	-9.3
• Adjustments made for the regulatory accounting numbers that don’t appear in the source information for the relevant regulatory templates	1.8	-3.9	-2.1	-11.7	0.9	-10.8	-7.9	-0.1	-8.0	-4.5	2.0	-2.5	-8.1	-0.6	-8.7
• Network Overheads and Corporate Overheads for ACS	-	10.2	10.2	-	15.5	15.5	3.5	16.0	19.5	8.7	14.4	23.1	7.6	11.3	18.9
Regulatory Accounting Statements	836.3	342.9	1,179.3	999.8	353.9	1,353.7	981.0	404.2	1,385.2	990.9	486.3	1,477.2	932.1	608.4	1,540.5
Adjusted for:															
• TUOS	-	246.6	246.6	-	286.0	286.0	-	343.8	343.8	-	390.0	390.0	-	394.3	394.3
• Finance costs	-	212.5	212.5	-	224.7	224.7	-	305.4	305.4	-	321.4	321.4	-	358.4	358.4
• Depreciation, amortisation & impairment	-	235.4	235.4	-	242.5	242.5	-	286.3	286.3	-	329.5	329.5	-	352.6	352.6
• Non-regulated services	11.4	123.1	134.5	-1.8	100.3	98.5	5.0	65.0	70.1	5.0	74.6	79.6	4.7	55.9	60.6
• Capitalised depreciation	23.3	-	23.3	28.4	-	28.4	-	-	-	-	-	-	-	-	-
Audited Statutory Accounts - Consolidated	871.0	1,160.5	2,031.5	1,026.4	1,207.4	2,233.8	986.0	1,404.7	2,390.8	995.9	1,601.8	2,597.8	936.8	1,769.5	2,706.4

Appendix 4 – Vegetation Management Zones Map

For a detailed view of the vegetation management zones please refer to the attached pdf.



Appendix 5 – 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 standards 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

- Other including training, OH&S functions, training, network billing and customer service & call centre

- 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 standards 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 departments identified below. It also includes the non-bookable time associated with team briefs, meetings, training, 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 are incurred within the following Energex departments:

- 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.
- 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 departments:
  - 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 Standards and 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 are incurred within the following Energex departments:
  - 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 Metering Support - 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 or departments.

- 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 ligation 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 departments

- 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 departments:
  - Financial Control - is responsible for the provision of financial and regulatory reporting (e.g. financial statements, RIN financial information, 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, 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 - Provides Group and Divisional financial reporting, budgeting, forecasting, Investment Review Committee governance and business case management. It also undertakes treasury, 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 departments:
  - 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 departments:
  - 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 6 – Cost Element Mapping to Input Table Categories

CA 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 Charges	SPARQ SLA SPARQ 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 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

Energex

Category Analysis RIN
Basis of Preparation
4. Alternative Control Services

May 2014

energex

positive energy

Version control

Version	Date	Description
1.0	20/05/2014	Version provided to KPMG
2.0	30/05/2014	Final version submitted to AER

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.

Group Manager
Regulation and Pricing
Energex
GPO Box 1461
BRISBANE QLD 4001

Table of Contents

1 BoP 4.1-1 – Public Lighting – Descriptor Metrics Over Current Year

The AER requires Energex to provide the following information relating to table 4.1.1:

- **The current population of lights, by light type**

1.1 Consistency with CA RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 1.1: 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 template 4.1
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 template 4.1
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 template 4.1
Energex must report data for non-contestable, regulated public lighting services. This includes work performed by third parties on behalf of Energex.	This requirement has been taken into account in preparing template 4.1
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 template 4.1
Energex is not required to report data in respect of GSLs, where a GSL	This requirement has been

Requirements (instructions and definitions)	Consistency with requirements
scheme does not exist for a public lighting service.	taken into account in preparing template 4.1
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 template 4.1

Actual information was provided for all variables in table 4.1.1.

1.2 Sources

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
The current population of lights, by light type	Peace / Oracle

1.3 Methodology

1.3.1 Assumptions

Energex has 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 in Energex on completion of the installation. Where design and construction services are requested to be undertaken by Energex by the Public Body, 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.
  - Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body

  In accordance with clause 17.6 of the RIN, 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.

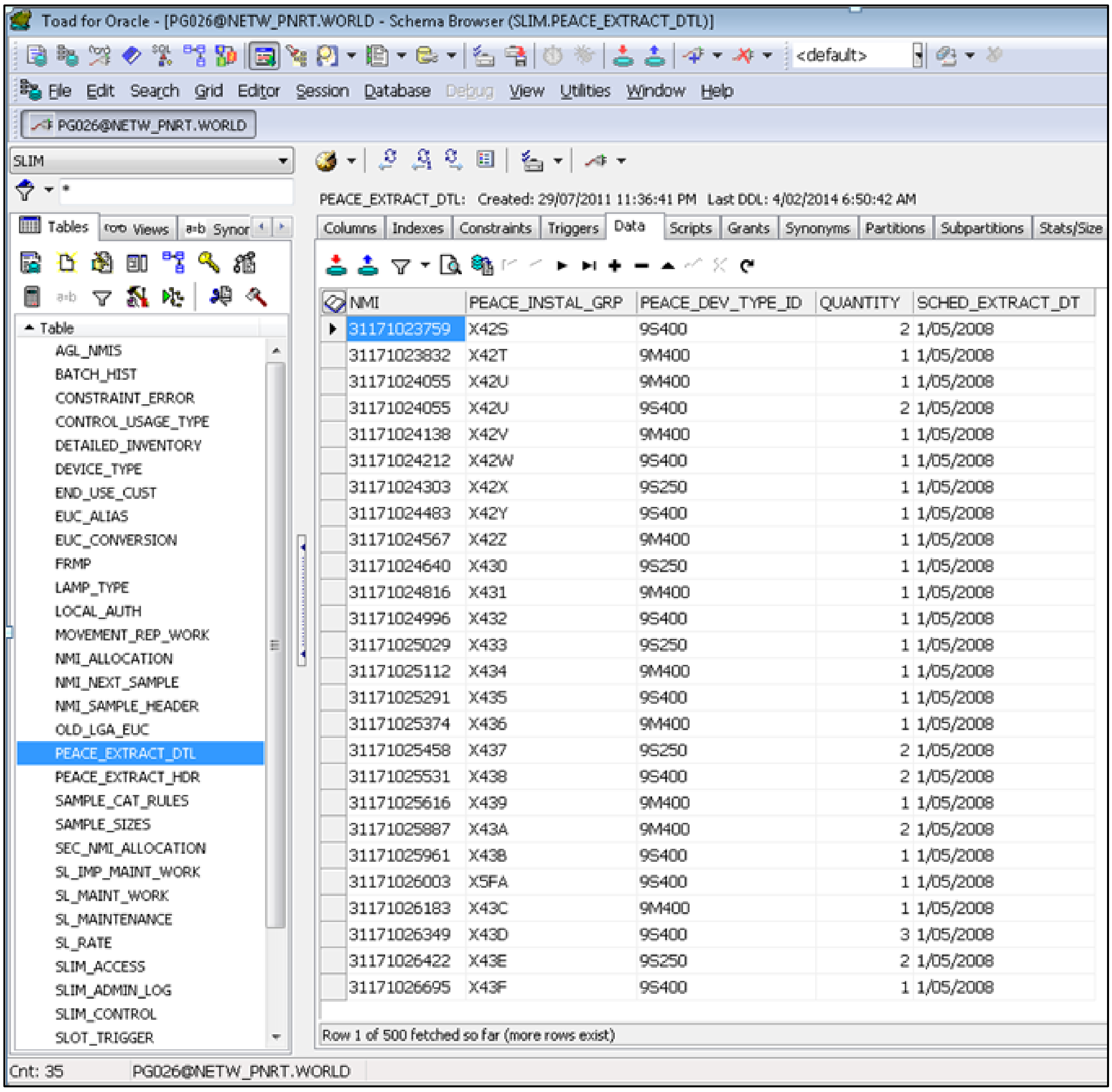
  For the purposes of template 4.1, Energex has included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.

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.

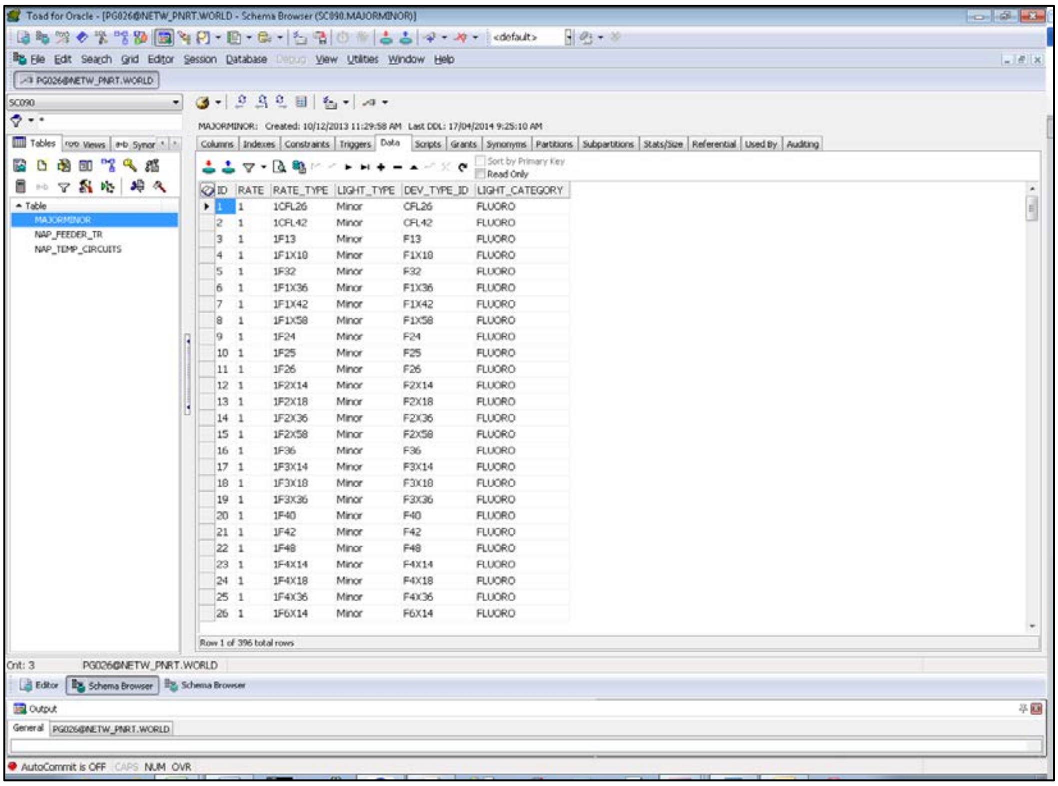
1.3.2 Approach

The approach required a report from the SLIM database and a report from 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.



- 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 streetglight category and by Major and Minor for the year 2012-13.

1.4 Estimates

Estimates were not required in providing the data for table 4.1.1.

1.4.1 Justification for estimates

Not applicable.

1.4.2 Basis for estimates

Not applicable.

1.5 Explanatory notes

Not applicable.

2 BoP 4.1-2 – Public Lighting – Descriptor Metrics Annually

The AER requires Energex to provide the following information relating to table 4.1.2:

- **For each year between the period 2008-09 and 2012-13:**
  - **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**

The values provided in table 4.1.2 are a combination of both actual and estimated information.

2.1 Consistency with CA RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 2.1: 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 template 4.1
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 template 4.1
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 template 4.1
Energex must report data for non-contestable, regulated public lighting	This requirement has been

services. This includes work performed by third parties on behalf of Energex.	taken into account in preparing template 4.1
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 template 4.1
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 template 4.1
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 template 4.1

Estimated information was provided for the following variables:

- Number of poles for all years for light installation
- Total cost for 2011/12 and 2012/13 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
- Major and minor road light installation volumes for 2008/09 for light maintenance
- Number of poles for all years for light maintenance
- Mean days to rectify/replace assets

All other information is based on actual data.

2.2 Sources

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

Table 2.2: 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
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
The value GSL payments	N/A
The volume of customer complaints	FROG, Cherwell

2.3 Methodology

2.3.1 Assumptions

General assumptions

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 in Energex on completion of the installation. Where design and construction services are requested to be undertaken by Energex by the Public Body, 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.
- Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body

In accordance with clause 17.6 of the RIN, 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 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

It was assumed that any light installed on a timber pole bracket did not involve installation of a dedicated street light pole as this would be a very small population of poles and are not discernable from other timber poles in Energex's asset records.

Customer Complaints

Complaints categorised as 'street lighting' relate to customer dissatisfaction with the establishment or maintenance of street lighting (that is, pole placement, lights not working , brightness of lights).

2.3.2 Approach

Light Installation – volume of works and expenditure

Major and minor road light installation volume

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):

- Date
- Works Order Number
- User Ref Id (site ID)
- Slot_Sun (unique record attached to each streetlight slot)
- Light Type
- Light Rating
- Major/Minor status
- Light Category

This query returned all Rate 1 and Rate 2 public lights installed on an annual basis.

As noted earlier, gifted public lights are to be excluded from 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.

From here, the dataset was saved as an Excel file and the Subdivisions Works Orders were removed, leaving all Non-Contributed (Rate 1) and Contributed lights (Rate 2) without the gifted lights.

The process was run for each of the financial year between 2008-09 and 2012-13 and each annual dataset was copied to a separate spreadsheet and pivot tables were created, filtering the results into Major and Minor light installations.

The total volume of public lighting installed was established by summing the number of public lights for Major and Minor for each financial year.

Number of poles installed

For all new lights installed annually between 2008-09 and 2012-13 (volume calculated above), the total number of new lights installed was multiplied by the percentage of the steel pole outreaches issued from Procurement and Supply (relative to the total population of all outreaches issued from stores). This provided an estimated value for the number of public light sites where was is assumed a new pole was installed. This calculation was performed separately for major and minor roads and summed together to produce a value for total poles installed.

It was assumed that any light installed on a timber pole bracket did not involve installation of a dedicated street light pole, as this would be a very small population of poles and are not discernable from other timber 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 on a one-to-one basis.

While Energex was able to identify the total number of additional new Rate1/Rate 2 minor and major streetlights added to the billing records each year, this does not identify those new streetlights installed on an existing distribution pole or requiring a new dedicated streetlight pole. Given the historically low volume of streetlights mounted on new wood poles installed solely for this purpose, it was assumed that the percentage split between steel/wood minor and steel/wood major brackets issued from Energex's Materials Distribution Centre (DC), would be a good indicator of the number of new minor and major streetlights installed on correspondingly new dedicated (steel) streetlight poles. For this purpose and noting that both Nostalgia and Avenue (decorative) luminaires are mounted on their integral outreaches (not included as a separate outreach in the minor road outreach volumes issued from stores, the number of Nostalgia and Avenue luminaires issued from the DC were added to the corresponding volume of minor (conventional) steel outreaches, so as to better reflect the true steel/wood minor bracket volume split.

Total cost

A report was run from Mincom Ellipse Reporting which listed all street lighting projects that incurred expenditure between the years 2008-09 and 2012-13 under the following financial activity codes:

Activity Code	Description
C2560	CWDA Public Lighting
C3560	Street Lighting

This report detailed all expenses and quantities booked against street lighting projects (both installations and replacements) over the five year period.

From this data set, a number of adjustments were made to exclude gifted assets and items relating to streetlight mains recovery projects.

- Gifted assets were excluded in accordance with clause 17.6 of the RIN. Projects with a transaction in expenses 6270 (Capital Contributions Non Cash Expenses) were removed from the data set.
- 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.

Cost data from each expense line item was then aggregated to provide the total cost of street lighting projects for each financial year.

For 2011/12 the total cost for installations is an estimate as the costs of replacement were subtracted from the total cost, leaving the remaining costs to be attributed to installations. The replacement cost for 2011/12 year is an estimate based on the average of the other four years reported in this template, as replacement data for this year was not available.

For 2012/13 the street lighting financial activities included installation and replacement. The cost attributed to installation is the remaining costs after the known cost of replacement was subtracted.

Light Replacement - volume of works and expenditure

<u>Major and minor road light replacement volume</u>

Projects relating to public light replacements are not explicitly identified in NFM. In most cases, where a streetlight has been 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:

(i) the volume of lights issued from the Procurement and Supply division

(ii) 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:

- Step 1: A report was extracted from Ellipse which provided a list of all streetlights issued by Procurement and Supply between the period 2008-09 and 2012-13.

  This report provided all Rate 1 and Rate 2 public lights issued by Procurement and Supply, representing volumes for both replacement and installation projects.

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

- Step 3: The total volume of public lighting for installations and replacements were established by summing the number of public lights for Major and Minor light types for each financial year.

- Step 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 Rate 2 categories (excluding gifted assets) by Major and Minor light types for each financial year.

- 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 for each year between 2008-09 and 2012-13.

Number of poles replaced

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). Data for 2011-12 was not available, therefore an average of the years 2008-09, 2009-10, 2010-11 and 2012-13 was used for the 2011-12 year. An average of the 4 years in is valid on the basis that pole replacement volumes are reasonably consistent year-on-year.

Total cost

Costs for street light replacements was derived from NAMP line SL04 - SL - Replace Unserviceable Pole. For the financial years 2008-09, 2009-10 and 2010-11 these costs were captured in activity C2545 – CWDA Pole Reinstatement. As activity C2545 is reported in the repex template 2.2, the costs associated with NAMP line SL04 have been removed from repex, and included in public lighting template for the total cost of light replacement.

The replacement cost for 2011/12 year is an estimate based on the average of the other four years reported in this template, as replacement data for this year was not available for this year. An average of the 4 years in is valid on the basis that pole replacement volumes are reasonably consistent year-on-year.

The costs for 2012-13 were capture 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).

Light Maintenance – expenditure and volume of works

Major and minor road light maintenance volume

The light maintenance volumes represent the actual number of luminaires maintained as part of the street light maintenance contract. 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.

Values for 2008-09 were based on the average of 2009-10, 2010-11, 2011-12 and 2012-13 as data was not separately identifiable for 2008-09.

Number of poles maintained

The number of poles maintained is not determinable on the basis that Energex's pole maintenance contract does not distinguish between poles for street lights and poles for distribution lines.

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 Cost

A report was run from Mincom Ellipse Reporting which listed all street lighting projects that formed part of the maintenance works between the years 2008-09 and 2012-13 under the following financial activity code:

Activity Code	Description
41600	Street Lighting

This report detailed all expenses and quantities booked against street lighting maintenance projects over the five year period. Cost data from each expense line item was then aggregated to provide the total maintenance cost of street lighting projects for each financial year. It is important to note that costs relating to maintenance of gifted assets was not excluded from the cost data as these assets could not be identified in the Ellipse report.

Quality of Supply

<u>Mean days to rectify / replace assets</u>

Mean days to rectify/replace assets is estimated data. 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.

A "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 form can be used to record up to seven lights needing repair.

After each patrol, a copy of Form 242 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.

Energex analysed the data inputted from each Form 242 for each year between 2008-09 and 2012-13, and calculated the average time taken to rectify public lighting assets for each 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 template 4.1 will tend to overstate the time taken to rectify / replace streetlights.

<u>Volume of customer complaints</u>

Complaint data is derived from a feedback report which extracts information from the Feedback Register for Organisational Growth (FROG) system (for volumes in 2008-09 to 2010-11) and the Cherwell system (for volume in 2011-12 onwards) 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.

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 for each financial year.

2.4 Estimates

The following data variables were estimated:

- Number of poles for all years for light installation
- Total cost for 2011/12 and 2012/13 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
- Major and minor road light installation volumes for 2008/09 for light maintenance
- Number of poles for all years for light maintenance
- Mean days to rectify/replace assets

2.4.1 Justification for estimates

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

2.4.2 Basis for estimates

Each of the variables that were estimated have 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.

2.5 Explanatory notes

Not applicable.

3 BoP 4.1-3 – Public Lighting – Cost Metrics

The AER requires Energex to provide the following information relating to table 4.1.3:

- **For each year between the period 2008-09 and 2012-13, 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 estimates.

3.1 Consistency with CA RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 3.1: 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 template 4.1
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 template 4.1
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 template 4.1
Energex must report data for non-contestable, regulated public lighting services. This includes work performed by third parties on behalf of Energex.	This requirement has been taken into account in preparing template 4.1

Requirements (instructions and definitions)	Consistency with requirements
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 template 4.1
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 template 4.1
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 template 4.1

Estimated information was provided for all variables in table 4.1.3.

3.2 Sources

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

Table 3.2: Information sources

Variable	Source
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

3.3 Methodology

3.3.1 Assumptions

General assumptions

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 in Energex on completion of the installation. Where design and construction services are requested to be undertaken by Energex by the Public Body, 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.
- Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body

In accordance with clause 17.6 of the RIN, 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 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.

<u>Average unit cost of installation</u>

Variations in the installation costs based on differing lamp types is 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:

- 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)
- Steel Overhead Major – the estimated unit cost includes installation of a new steel pole and provision of a 40 metre span of overhead service
- Underground Major – the estimated unit cost includes installation of a new steel pole and provision of a 30 metre length of underground supply
- 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)
- Minor Road Steel – the estimated unit cost includes the installation of a new decorative steel pole and provision of a 5 metre length of underground supply

All costs for the street light constructions above were estimated at current cost rates (i.e., 2013-14). These costs were then deescalated by CPI to derive an estimate for each year between the period 2008-09 and 2012-13.

<u>Average unit cost of replacement</u>

The light types provided in table 4.1.3 for replacements represent the standard luminaires during the period. These include the following:

- High Pressure Sodium Major 150W
- Mercury Vapour Minor 50W
- High Pressure Sodium Minor 70W

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.

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.

The average unit cost data included the estimated cost of supply and replacement of a luminaire, lamp and photoelectric cell.

<u>Average unit cost of maintenance</u>

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.

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:

- Actual cost for luminaire maintenance (excluding luminaire replacement costs)
- Actual Streetlight circuit maintenance costs
- Actual Streetlight patrol costs

3.3.2 Approach

<u>Average unit cost of installation</u>

The average unit cost of street light installations was estimated for the 5 types of standard contractions:

- Wood Pole Major – as describe 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. This is detailed in estimate reference number 92431 (version 5).

- Steel Overhead Major – as describe 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. This is detailed in estimate reference number 92434 (version 5).

- Underground Major – as describe 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. This is detailed in estimate reference number 92435 (version 5).

- Wood Pole Minor – as describe 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. This is detailed in estimate reference number 92430 (version 7).

- Minor Road Steel – as describe 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. This is detailed in estimate reference number 92433 (version 7).

<u>Average unit cost of replacement</u>

The average unit cost of street light replacements was estimated for the 3 types of luminaires (as identified in the assumptions section). The methods for calculating the estimated unit costs are outlined below:

- 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. This is detailed in estimate reference number 424075 (version 02).

- Mercury Vapour Minor 50W – 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. This is detailed in estimate reference number 424068 (version 02).

- 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. This is detailed in estimate reference number 424071 (version 02).

The values calculated in the estimates above were adjusted to present the figures in 2012-13 terms, as the contracted services portion of the estimate had changed by other than CPI from 2013-14. These value for each type of luminaire was deescalated by CPI to derive an estimate for each year between the period 2008-09 and 2012-13.

Average unit cost of maintenance

The unit cost data of maintenance is comprised of the following:

- Actual cost for luminaire maintenance (excluding luminaire replacement costs)
- Actual Streetlight circuit maintenance costs
- Actual Streetlight patrol costs

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.

The costs for these activities were sourced from Energex's streetlight maintenance contract for each year between 2008-09 and 2012-13, 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 for each financial year.

3.4 Estimates

Estimated information was provided for all variables in table 4.1.3.

3.4.1 Justification for estimates

Energex does not capture costs data for the variables in table 4.1.3. As such, Energex was required to prepare estimates for these variables.

3.4.2 Basis for estimates

Each of the variables that were estimated have 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.

3.5 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 faulty PE cells
- 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 peaks and valleys (uneventful years) in the graphs.

4 BoP 4.2.1 – Metering

The AER requires Energex to provide the following information relating to Table 4.2.1 – Metering Descriptor Metric:

- **Meter Type 4 - Volume of the in-service meter population**
- **Meter Type 5 - Volume of the in-service meter population**
- **Meter Type 6 - Volume of the in-service meter population**

The AER requires Energex to provide the following information relating to 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**

Actual information was provided for meter volumes installed and recent labour costs for following service subcategories:

- **Table 4.2.1:**
  - **All figures**
- **Table 4.2.2:**
  - **Meter Purchase expenditure & volumes**
  - **Scheduled Meter Reads expenditure and volume**
  - **Special Meter Reads expenditure and volume**
  - **Other Metering expenditures**
  - **Meter Testing volumes**

Estimated information was provided for all other subcategories in table 4.2.2.

4.1 Consistency with CA RIN Requirements

Table 4.1: 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 contract agreement expenditure report
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 Table 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 costs have been used where available, and was reliably accessible during preparation of the report
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 volumes and costs have been used where detailed information was limited to specific individual unit
p80 of the AER Explanatory Statement states for 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.	The meter numbers have been calculated as the average during the financial year.

Actual information was provided for meter volumes installed and recent labour costs for following service subcategories:

- Table 4.2.1:
  - All figures
- Table 4.2.2:
  - Meter Purchase expenditure & volumes
  - Scheduled Meter Reads expenditure and volume
  - Special Meter Reads expenditure and volume
  - Other Metering expenditures
  - Meter Testing volumes

Estimated information was provided for all other subcategories in table 4.2.2.

4.2 Sources

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

Table 4.2: Information sources

Variable	Source
Table 4.2.1 – Meter Populations	Peace
Table 4.2.2 – Cost Metrics Expenditure	Peace, Ellipse, ACS Quote Mode, Business Objects Reports
Table 4.2.2 – Cost Metrics Volume	Peace, Ellipse, MARS, Business Objects Reports

4.3 Methodology

4.3.1 Assumptions

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

- The labour expenditure was adjusted using the average CPI percentage as published by the Australian Bureau of Statistics for each respective financial year
- With regards to on-site work, different jobs take different times to complete due to changes in travel times or other factors. The effects of different job timings have been ignored and thus the volume of onsite work assumes an average time is taken to complete a normal job.

- 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.

4.3.2 Approach

The following approach was used to obtain the required information:

1) Table 4.2.1 – Meter Populations

2) 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 of each financial year. 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 over lapping of the volume between single phase volume and CT connected volume to meter installation type. 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.

3) Table 4.2.2 – Meter Purchase expenditure and volume

A report was extracted from Ellipse Explorer application ELL00137 on each supplier of metering equipment and exported into excel for each financial year. This report was then filtered to actual metering equipment type by individual stock code, quantity and expenditure without manipulating any values. The figures provided are actuals in quantity and expenditure as registered in Ellipse.

4) Table 4.2.2 – Meter Testing expenditure and volume

This item volume and expenditure figures are actual as per contract report extracted from Ellipse CL97, 07037A, 07037B and 10202. An extract out of MARS was also exported to consolidate actual volume of testing request for each financial year as specified by AER. There is no material cost included on this line item.

5) Table 4.2.2 – Meter Investigation expenditure and volume

The volume and expenditure figures are extracted from the Peace CIS report PCE021 on the basis of the number of service orders being successfully completed on the site relevant to investigation. The expenditure figures exclude material cost.

6) Table 4.2.2 – Scheduled Meter Reads expenditure and volume

These numbers for scheduled meter reads are based on actual reads reported through business objects reports. These reports extract the figures as collected by the meter readings systems and actual dollars paid to the contractor under the contract rates.

7) Table 4.2.2 – Special Meter Reads expenditure and volume

These numbers for special meter reads are based on actual reads reported through business objects reports. These reports extract the figures as collected by the meter readings systems and actual dollars paid to the contractor under the contract rates.

8) Table 4.2.2 – New Meter Installation expenditure and volume

The volume and expenditure figures were extracted from the Peace CIS report PCE018 on the basis of number of the meters being installed by financial year. The expenditure figures include material costs for other metering equipment on the basis of meter type and Peace CIS report PCE021 for load control relay installation.

9) Table 4.2.2 – Meter Replacement expenditure and volume

The volume and expenditure figures were extracted from the Peace CIS report PCE021, contract CL97, 07037A, 07037B, 10202 and MARS on the basis of number of service orders being successfully completed on the site relevant to each replacement for each financial year. The expenditure includes material cost of metering equipment where appropriate. Where the information is sourced from contracts, the values are actuals and where the system extracts have been used, the values are estimated.

10) Table 4.2.2 – Meter Maintenance expenditure and volume

The volume and expenditure figures are extracted from the Peace CIS report PCE021 on the basis of number of service orders being successfully completed on site relevant to maintenance as defined by AER for each specified financial year. The expenditure figures exclude all material cost.

11) 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.

12) 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.

13) Table 4.2.2 – Other Metering expenditure

Report was extracted from Ellipse Explorer application ELL00137 for each supplier of metering equipment. This was then exported into excel for each financial year as specified by AER. This report was then filtered to show actual metering equipment type, quantity and expenditure without manipulating any values. These figures also include refurbished equipment where applicable with actual expenditure as registered in Ellipse.

14) 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.

15) 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.

16) General – Expenditure calculation (Labour)

Where reliable information was not available with respects to historical internal labour costs, the labour rate was calculated based on the labour rates for the current year. The current year cost rates were de-escalated using the CPI figures obtained from the ABS back to the respective years required.

4.4 Estimates

Energex has used actual data in tables 4.2.1 and 4.2.2 where was available and considered reliable. Where historical data was not available, or considered unreliable, estimated quantities and costs were used.

4.4.1 Justification for estimates

Estimation of some historical data was required because the actual data was either not collected by field workers, or not recorded in current reporting systems. Metering work is usually completed as part of a new connection and service installation, and the same field workers do all these tasks and the historical costs were captured for the whole job (all tasks) including travelling to and from the job. Splitting the metering work from the other tasks done at the same time required estimation.

Please note the following with respect to the metering estimates:

- Estimates are based on records and information compiled by field staff using systems and processes that were developed and used at a time when the level and accuracy of labour costing detail was not required or was considered secondary to getting the work done efficiently.

- Energex records better information with respect to services provided by external contractors. Where costs have been derived purely from contractor costs the data is considered actuals. Where data contains internal labour costs this constitutes estimated data.

4.4.2 Basis for estimates

Energex used their work estimation system and consultation with field workers and their supervisors to determine appropriate labour cost estimates for earlier years. Labour costs were de-escalated using the CPI figures from the ABS.

4.5 Explanatory notes

Floods, storms and changing from electromechanical to electronic meters have resulted in an abnormal distribution of meter purchases over the years. Also changes between refurbishing and purchasing meters have impacted the quantities reported.

Government initiated solar PV incentive schemes resulted in a substantial increase in meter replacement work, to provide the export data capability needed for the resulting tariff. Other tariff reforms and smart meter / smart grid projects have also resulted in additional meter purchases and labour costs in recent years.

Scheduled meter reads and special meter reads

An anomaly in 2010 is caused by the change in contract conditions and meter reading rates. The period July 2009 to June 2010 (2010) was the last year of the previous contract and the period July 2010 to June 2011 (2011) was the first year of the new contract. A renegotiation of the rates was based on going back to market and competition between potential contractors.

5 BoP 4.3-1 – Fee Based and Quoted Alternative Control Services

The AER requires Energex to provide the following information relating to Template 4.3:

- **Expenditure and volumes for all fee-based services listed in Energex's annual tariff proposal for each year between the period 2008/09 and 2012/13.**

The AER requires Energex to provide the following information relating to Template 4.4:

- **Expenditure and volumes for all quoted services listed in Energex's annual tariff proposal for each year between the period 2008/09 and 2012/13.**

Estimated information has been provided for particular Fee-Based Services expenditure in Template 4.3 for 2011 and 2012.

Actual information was provided for all other variables in Templates 4.3 and 4.4.

5.1 Consistency with CA RIN Requirements

Table 5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for fee-based and 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 4.3 and 4.4, Energex must list all the Fee Based and Quoted services that were listed in the annual tariff proposal of each relevant year.	As per the annual tariff proposal for Fee Based and Quoted services, Energex has continued to apply the corresponding level of detail in the CA RIN
In the basis of preparation, Energex must provide a description of each Fee Based and Quoted service listed in the regulatory templates 4.3 and 4.4. In each services' description, Energex must explain the	For 2008-09, this information is provided in Appendix 1.1 – Excluded

Requirements (instructions and definitions)	Consistency with requirements
purpose of each service and detail the activities which comprise each service.	Distribution Services Pricing Schedule 2008-09[1] For 2009-10, this information is provided in Appendix 1.2 – Tariff Schedule 2009-10 For 2010-11 to 2012-13, this information is provided in Appendix 1.3 – 2012-13 Annual Tariff Schedule
Energex is not required to distinguish expenditure for Fee Based and Quoted services between standard or alternative control services in regulatory templates 4.3 and 4.4.	As per the current annual RIN, there is no cross over between the services under standard and alternative control services (ACS). Fee Based and Quoted Services are only ACS
Energex is not required to distinguish expenditure for Fee Based and Quoted services as either Capex or Opex in regulatory templates 4.3 and 4.4.	Energex has applied this consistency requirement

Estimated information has been provided for particular Fee-Based Services expenditure in Template 4.3 for 2011 and 2012. Actual information was provided for all other variables.

5.2 Sources

Table 5.2 below sets out the sources from which Energex obtained the required information.

Table 5.2: Information sources

Variable		Source
Expenditure dollar values for fee based services and quoted services	2008-09, 2009-10	Annual regulatory accounts and workpapers
	2010-11	Ellipse Detailed Transaction Reports, including details of direct vs overhead costs

[1] Note the following: (a) Design Fee/Deposit and Metering in the 2008-09 Tariff Schedule were not included in the 2009-10 tariff schedule; and (b) Special Reads in the 2008-09 Tariff Schedule was renamed as Meter Read in the 2009-10 Tariff Schedule

Variable		Source
		Total Fee Based and Quoted Services Opex Costs (including overhead) as per the Audited Annual RIN
	2011-12	Ellipse Profit & Loss Reports Ellipse Detailed Transaction Reports including details of direct vs overhead costs Total Fee Based and Quoted Services Opex Costs (including overhead) as per the Audited Annual RIN
	2012-13	Audited Annual RIN submitted to the Australian Energy Regulator
Volumes for fee based services and quoted services	2008-09, 2009-10	Annual regulatory accounts and workpapers
	2010-11, 2011-12, 2012-13	Annual pricing proposal submitted to the Australian Energy Regulator

5.3 Methodology

Below is the methodology that was taken to report the Fee Based and Quoted Services expenditure and volumes as per the outlined requirements in the RIN.

5.3.1 Assumptions

The following assumptions were made in providing the data for Templates 4.3 and 4.4:

- Energex has consistently reported direct costs throughout the CA RIN. This means that overhead costs have been excluded from the Fee-Based and Quoted Services figures reported in Templates 4.3 and 4.4.
- An apportionment of certain Fee-Based services (detailed below in section 5.3.2) has been applied to report the individual sub-categories.

5.3.2 Approach

Energex applied the following approach to obtain the required information for the Fee Based and Quoted services expenditure and volumes.

Expenditure dollar values

- 2008-09 & 2009-10
  - Alternative Control-equivalent services for the previous Determination period (classified as Excluded Distribution Services from 2007-08 to 2009-10) were not further sub-classified as Fee-Based or Quoted Services. For CA RIN purposes, Energex has determined this sub-classification based on a review of the workpapers for the regulatory accounts for the relevant years. In most cases:
    - Business-to-Business (B2B) services provided to retailers have been classified as Fee-Based
    - Price on Application (POA) services and Infrastructure Projects (conducted under State Government infrastructure development initiatives, which are similar in nature to Rearrangement of Network Assets) have been classified as Quoted Services
  - Exceptions relate to services which can be both Fee-Based and Quoted, dependant on the nature. For example, simple services for Temporary Connections are Fee-Based whereas complex services are Quoted Services.
  - Service categories match those in the annual Tariff Schedules. As services were not sub-classified as Fee-Based or Quoted Services, all services in the Tariff Schedule have been included in both table 4.3.1 for Fee-Based Services and 4.4.1 for Quoted Services.
  - Figures reconcile to those reported in the annual regulatory accounts excluding overheads.
- 2010-11
  - The expenditure dollar values for fee-based and quoted services for 2010-11 were extracted from Ellipse Detailed Transactions reports.
  - The audited Annual RIN 2010-2011 provides the total operational expense including overheads, as per AER requirements[2]. Expenditure values in tables 4.3.1 and 4.4.1 were adjusted to exclude overheads, which were sourced from the Ellipse Detailed Transaction report.
  - Energex's financial reports in 2010-11 did not disaggregate to the level required in tables 4.3.1 and 4.4.1, as this level of reporting commenced in 2012-13. Therefore for the categories in the table below, the total figures for each Energex Financial Category were disaggregated as per the percentage distribution for the 2012-13 financial year.

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %
Meter Inspect	Meter test	66.13%

[2] Page 23, Table 7a.1, row "Other operating costs (incl self-insurance), column Alternative Control Services

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %
Meter Inspect	Meter inspection	33.87%
Re-energisation	Re-energisation - business hours	8.19%
Re-energisation	Re-energisation - after hours	2.67%
Re-energisation	Re-energisation (visual) - business hours	75.73%
Re-energisation	Re-energisation (visual) - after hours	13.38%
Re-energisation	Re-energisation non-payment (visual) - business hours	0.02%
Re-energisation	Re-energisation non-payment (visual) - after hours	0.01%
Fee Based Streetlighting	Street light glare screening	71.49%
Fee Based Streetlighting	Replacement of standard luminaries with aero screen units (per street light)	28.51%

- 2011-12
  - Ellipse Profit & Loss Reports and the Ellipse Detailed Transactions reports were used to extract the expenditure requirements for tables 4.3.1 and 4.4.1.
  - The audited Annual RIN 2011-12 provides the total operational expense including overheads. Expenditure values in tables 4.3.1 and 4.4.1 were adjusted to exclude overheads, which were sourced from the Ellipse Detailed Transaction report.
  - Energex's financial reports in 2011-12 did not disaggregate to the level required in tables 4.3.1 and 4.4.1, as this level of reporting commenced in 2012-13 year. Therefore, for the categories in the table below, the total figures for each Energex Financial Category were disaggregated as per the percentage distribution for the 2012-13 financial year.

-

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %
Meter Inspect	Meter test	66.13%
Meter Inspect	Meter inspection	33.87%
Re-energisation	Re-energisation - business hours	8.19%
Re-energisation	Re-energisation - after hours	2.67%
Re-energisation	Re-energisation (visual) - business hours	75.73%
Re-energisation	Re-energisation (visual) - after hours	13.38%
Re-energisation	Re-energisation non-payment (visual) - business hours	0.02%
Re-energisation	Re-energisation non-payment (visual) - after hours	0.01%
Fee Based Streetlighting	Street light glare screening	71.49%
Fee Based Streetlighting	Replacement of standard luminaries with aero screen units (per street light)	28.51%

- 2012-13
  - The audited Annual RIN 2012-13[3] provided the detailed expenditure figures required in tables 4.3.1 and 4.4.1.

Volumes

- 2008-09 & 2009-10
  - The total volumes of services reported equal those in the regulatory accounts each year. The disaggregation between Fee-Based and Quoted Services has been sourced from the regulatory account workpapers.
  - Volumes reported represent the number of services billed to customers.
  - Schedule 8 of the *Queensland Electricity Regulation 2006* caps the price of particular services, meaning that Energex cannot charge customers for these

[3] page 34

services. Accordingly, no volumes have been reported for de-energisations and re-energistations during business hours for these two years.

- 2010-11, 2011-12, 2012-13
  - As information on volumes is no longer required as part of the annual RINs, all volumes were obtained from the Annual Pricing Proposal submitted to the Australian Energy Regulator.
  - The volume for Energy Efficient Street Lights in 2012-13 was not available from the pricing proposal however this service is reported in the annual RIN.
  - These volumes represent the number of services performed, including all de-energisations and re-energisations.

5.4 Estimates

Estimated information has been provided for particular Fee-Based Services expenditure in Template 4.3 for 2011 and 2012.

5.4.1 Justification for estimates

Prior to the 2012-13 years, Energex's financial reports did not disaggregate all services to the level required in table 4.3.1. Therefore actual percentages for the individual services for 2012-13 have been used to allocate the aggregated services to individual services for 2010-11 and 2011-12.

5.4.2 Basis for estimates

The expenditure figures in Template 4.3 Fee-Based Services for the 2010-11 and 2011-12 financial years for the below listed categories were apportioned using the actual percentages from the 2012-13 year.

- meter test
- meter inspection
- Re-energisation - business hours
- Re-energisation - after hours
- Re-energisation (visual) - business hours
- Re-energisation (visual) - after hours
- Re-energisation non-payment (visual) - business hours
- Re-energisation non-payment (visual) - after hours
- Street light glare screening
- Replacement of standard luminaries with aero screen units (per street light)

A detailed allocation of these percentages can be found in the above section 5.3.2 Approach.

5.5 Explanatory notes

1) Rearrangement of Network Assets

   After consultation with the AER in 2010, major asset rearrangements involving upgrades to the shared network have been classified as SCS capex, with the revenue treated as a capital contribution. Consequently, Rearrangement of Network Assets expenditure in 2012-13 is negative, as the result of the reclassification of expenditure for projects originally created as ACS opex, but which needed to be converted to SCS capex upon completion (this conversion process was delayed for projects already in progress, due to technical difficulties). The expenditure for these projects was previously reported as ACS opex as incurred.

2) 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.

3) Overhead service replacement no expenditure 2010-11 and 2011-12

   Prior to 2012-13 Energex was conducting an Overhead service lines safety upgrade project. This project was to upgrade any overhead service lines that did not meet current safety standards. Therefore, this fee based service did not obtain any customer requests during the 2010-11 and 2011-12 period.

4) Energy Efficient Streetlights

   Prior to 2012-13 this service was captured under the category for Quoted Services Other Recoverable Works due to the low expenditure.

   The volume for Energy Efficient Street Lights in 2012-13 was not available from the pricing proposal however this service is reported in the annual RIN.

5) 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.

Appendix 1 – Tariff Schedules

Appendix 1.1 - Excluded Distribution Services Pricing Schedule 2008/09 – Version 3: 27 August 2008

Appendix 1.2 - Tariff Schedule 2009-10 – Version 2a: July 2009

Appendix 1.3 - Tariff Schedule for the period 1 July 2012 to 30 June 2013 – Version 9

ENERGEX LIMITED

ABN 40 078 849 055

Excluded Distribution Services Pricing Schedule 2008/09

Version 3: 27 August 2008

To apply on and from 28 September 2008 (or as subsequently updated)

TABLE OF CONTENTS

1. INTRODUCTION

The 2008/09 Excluded Distribution Services (EDS) Price Schedule outlines prices for the provision of services ancillary to the main network services requested by either: customers and registered contractors / builders / developers; and retailers. The schedule applies from 28 September 2008 or as subsequently revised.

2. SERVICE CATEGORISATION

ENERGEX provides a broad range and standard of service at the explicit request of retailers and end-use customers. For ease of reference the services have been grouped into the following categories:

- Additions and Alterations;
- Callout Charge;
- De-energisations;
- Design Fee/Deposit;
- Meter Investigation;
- Meter Reconfiguration;
- Metering;
- Miscellaneous;
- New Connection;
- Re-energisations;
- Special Reads;
- Street Lighting Work;
- Supply Abolishment; and
- Unmetered Supply.

The services performed in the above listed categories are provided on a fee for service basis where the price charged will be either:

- A Scheduled Fix Fee if a standard service has been requested; or
- A Price on Application (POA) if a non-standard service has been requested.

A non-standard service is a service that is not considered standard due to the variation in the scope, timing and complexity of the work requested.

Conditions and prices pertaining to services provided are outlined in further detail below.

3. STANDARD EXCLUDED DISTRIBUTION SERVICES

Detailed below are the conditions and prices applicable to standard EDS.

3.1 Conditions applicable to Standard Excluded Distribution Services

Completion of service requests by ENERGEX will occur in accordance with the requirements of Chapter 5 of the *Electricity Industry Code: Third Edition.*

For connection points with a NMI classification code of 'Large' the service request will be carried out by ENERGEX in accordance with the time frames agreed between the parties. For connection points with a NMI classification code of 'Small' the service request will be carried out by ENERGEX in accordance with the time frames for each particular type of service classification, as outlined below.

3.1.1 Additions and Alterations to Customer Connections

Additions and Alterations (Ads and Alts) service requests can arise for a large number of reasons related to making a physical change to the supply at a given connection point. ENERGEX provides the following standard Ads and Alts services:

- Exchange Meter[1]
- Install Meter (non-business hours) [2]
- Overhead Service Replacement – Single or Multiple Phases

ENERGEX undertakes to complete requested work within 10 business days of:

- Receipt of a valid service order request; and
- Receipt of all relevant documentation – i.e. Form 2

Ads and Alts services will not be completed unless ENERGEX has received a Form 2 from the customer's electrical contractor.

3.1.2 Callout Charge

A callout charge service arises where ENERGEX attends a customer's trouble call and finds fault in the customer's installation. This includes tripped safety switch, internal fault, customer overload, etc.

3.1.3 De-energisations

A Retailer may request ENERGEX, as a service provider to de-energise a Connection Point for a variety of reasons. These include:

- Where the Retailer has grounds to proceed with a De-energisation for non-payment (e.g. where a customer has failed to meet their obligations under jurisdictional rules);

[1] This service is provided during business hours only.
[2] This service relates to specific requests by customers to install the meter either after hours or as a priority anytime.

- The customer requires a temporary disconnection of supply because the site is to be left vacant for a time; or
- The customer is moving out of a premise and no new tenant has requested supply at the same address.

De-energisation methods may involve:

- Removal of fuse;
- Disconnection at pole top, pillar box or pit; or
- Application of sticker to the meter.

ENERGEX provides the following standard De-energisation services:

- Pillar box, pit or pole top[3];
- Remove fuse[3];
- By sticker; and
- De-energisation requiring planned notification.

De-energisations are performed by ENERGEX in business hours only.

ENERGEX undertakes to complete the requested service within 6 business days of receipt of a valid service order request for all premises excluding premises in excluded locations[4]. For premises located in excluded locations the requested service will be completed within 10 business days.

A De-energisation for a small customer will not take place:

- After 3:00pm on a business day;
- On a Friday or a day before a public holiday[5];
- On a weekend or a public holiday;
- Between 20 December and 31 December (inclusive).

3.1.4 Meter Investigation

A service request to investigate the metering at a given Connection Point can arise in two circumstances:

- A customer raises a request with the Retailer where the customer believes that there is a problem with the metering installation; and

- Where the Retailer requests an investigation on the grounds of: suspected fraud and/or tampering; or consistent abnormal metering readings suspected to be caused by a faulty meter.

[3] This service may be requested for debt or change of occupancy.
[4] Excluded locations are specified in Appendix 2 to this price schedule.
[5] Public holiday means a Queensland wide public holiday and a local holiday in the district where the premise is located.

A meter test where ENERGEX checks that the metering installation is accurately measuring the energy consumed is provided during business hours only. ENERGEX undertakes to complete the service request within 15 business days of receipt of a valid service order request.

3.1.5 Meter Reconfiguration

A meter reconfiguration service request arises where a Retailer requires to reprogram the meter at a given Connection Point to reflect a tariff or time switch change to the customer. ENERGEX provides the following standard meter reconfiguration services:

- Change Tariff; and
- Change Time Switch

The above listed services are performed by ENERGEX during business hours only. ENERGEX undertakes to complete the requested work within 20 business days of receipt of a valid service order request.

3.1.6 Miscellaneous

A miscellaneous service request can arise for a number of reasons and consists of services which are not covered under the other type of service requests. ENERGEX provides the following standard miscellaneous services:

- Additional crew;
- Locating ENERGEX underground cables[6];
- Wasted truck visit[7]; and
- Additional communication charge[7].

The timeframe to complete requested work will depend on the type of work requested and will be subject to commercial negotiation between the distribution entity and the retail entity after receipt of a valid service order request.

3.1.6 New Connections

A service request to arrange a new supply connection at a specified address can arise in a number of circumstances, including:

- A customer moving into a new premise which currently does not receive an electricity supply; or

- A builder wishes to provide permanent or temporary supply to new properties under construction.

ENERGEX provides the following standard new connection services:

[6] This service is provided during business hours only.

- Underground permanent supply[7];
- Overhead permanent supply[7];
- Temporary connection[8];
- Temporary in Permanent[9].

ENERGEX undertakes to complete requested work within 5 business days of:

- Receipt of a valid service order request; and
- Receipt of all relevant documentation – i.e. Form 2.

New connections will not be completed unless ENERGEX has received a Form 2 from the customer's electrical contractor.

3.1.7 Re-energisations

A service request to re-energise a connection point may arise where a customer:

- Is moving into a premise;
- Has previously requested that a supply be temporarily de-energised and now wishes the supply to be restored; or
- Has been disconnected for non-payment.

ENERGEX provides the following standard re-energisation services:

- Re-energisation after disconnection for non-payment;
- Re-energisation after disconnection for non-payment (visual)[10];
- Re-energisation visual[11]; and
- Re-energisation - read required[12]

ENERGEX undertakes to complete the requested service on the same business day where a valid service order request is received by 1:00pm on a business day. Otherwise the work will be completed by the next business day. These timeframes are for all premises except those premises in excluded locations[13]. For premises in excluded locations the service request will be completed within 10 business days of receipt of a valid service order request.

For safety reasons, re-energisation services requiring a visual safety examination will only be undertaken within daylight hours.

[7] This service relates to a specific request by customers to undertake connection of supply either after hours or on a priority anytime.
[8] This service is provided by ENERGEX during business hours, after hours or on an anytime basis.
[9] This service relates to a specific request by customers to undertake connection of supply either after hours or on a priority anytime.
[10] A visual safety examination is required for re-energisations after disconnection for non-payment if: the connection point has been de-energised for greater than 1 month.
[11] A visual safety examination is required for re-energisations after disconnection where there has been a change of customer or retailer at the premise.
[12] This service is provided during business hours only.
[13] A list of excluded locations is provided in Appendix 2 of this Price Schedule.

3.1.8 Special Read

A special read request arises for manually read metering where an out of cycle reading is required.

ENERGEX undertakes to complete the requested work within 4 business days of receipt of a valid service order request.

All special reads are performed within business hours only.

3.1.9 Street Lighting Work

ENERGEX provides a range of standard street lighting work services, including:

- Standard luminare glare screening - internal;
- Adhesive luminare glare screening;
- Unique luminare glare screening – external; and
- Replacement of standard luminare with aeroscreen units.

The time frame for completion of service request will depend upon the work requested and will be subject to commercial negotiation between the distribution entity and the customer.

3.1.10 Supply Abolishment

A supply abolishment, where the NMI and all the associated metering is decommissioned, may be requested for a variety of reasons, such as:

- A property is to be demolished or its usage changed and a supply is no longer required; or
- An alternative connection point can be used and the redundant supply is to be removed.

ENERGEX undertakes to complete the service request to abolish supply at a given connection point within 20 business days of receipt of a valid service order request.

For supply abolishment service orders, Retailers must ensure that a Form 1345 (available from ENERGEX's website) is completed and returned to ENERGEX. This form should be faxed or emailed at the same time as lodging the supply abolishment service order request.

3.1.11 Unmetered Supply

ENERGEX provides a range of standard unmetered services. These include:

- Unmetered supply connection – connection point not available;
- Unmetered supply disconnection; and
- Temporary unmetered supply

The timeframe for completion of service requests will depend on the work requested and will be subject to commercial negotiation between the distribution entity and the retail entity after receipt of a valid service order request. All unmetered service requests are undertaken during business hours only.

3.2 Prices applicable to Standard Excluded Distribution Services

Prices for standard EDS are provided in the table below:

Service Information			Business Hours								
			General			*No CT*			*CT*		
Class	*Service*	*Service Description*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*
Adds & Alts	Exchange Meter	Exchange of one meter for another				AAEM1M	130.95	144.05	AAEM2M	366.75	403.42
Adds & Alts	Move Meter	Meter requires relocation				AAMM1M	130.95	144.05	AAMM2M	366.75	403.42
Adds & Alts	Overhead Service Replacement, Single Phase - 1 visit	To recover and replace an existing overhead service at customer's request. No material change to load.	MSRO1P1	210.02	231.03						
Adds & Alts	Overhead Service Replacement, Two Phase - 1 visit	To recover and replace an existing overhead service at customer's request. No material change to load.	MSOR2P1	261.90	288.09						
Adds & Alts	Overhead Service Replacement, Three Phase - 1 visit	To recover and replace an existing overhead service at customer's request. No material change to load.	MSOR3P1	314.77	346.24						
Adds & Alts	Overhead Service Replacement, Single Phase - 2 visit	To recover and replace an existing overhead service at customer's request. No material change to load.	MSOR1P2	440.06	484.06						
Adds & Alts	Overhead Service Replacement, Two Phase - 2 visit	To recover and replace an existing overhead service at customer's request. No material change to load.	MSOR2P2	523.91	576.30						
Adds & Alts	Overhead Service Replacement, Three Phase - 2 visit	To recover and replace an existing overhead service at customer's request. No material change to load.	MSOR3P2	649.71	714.69						
Callout Charge	Attending Loss of Supply LV - Customer's Installation at Fault	ENERGEX attended LVcustomer's trouble call during business hours and found fault in LV customer's installation (includes tripped safety switch, internal fault, customer overload, etc)	LOS	157.16	172.88						

Service Information			Business Hours								
			General			*No CT*			*CT*		
Class	*Service*	*Service Description*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*
De-energisation	Pillar box, Pit or Pole Top	De-energisation by a physical disconnection of the service mains at the connection to the network				DNSD1MB	0.00	0.00	DNSD2MB	0.00	0.00
De-energisation	Pillar box, Pit or Pole Top (Non-Payment)	De-energisation by a physical disconnection of the service mains at the connection to the network for non-payment				DN$1MB	0.00	0.00	DN$2MB	0.00	0.00
De-energisation	Remove Fuse	De-energisation at the fuse or meter				DNF1MB	0.00	0.00	DNF2MB	0.00	0.00
De-energisation	Remove Fuse (Non-Payment)	De-energisation at the fuse or meter as part of a non-payment process				DNF$1MB	0.00	0.00	DNF$2MB	0.00	0.00
De-energisation	De-energisation required planned notification (less than 10 customers)	ENERGEX is requested by a retailer to reconnect or disconnect a customer within a multiple premises compound. Works can only be completed at switchboard and may require notice to all occupants of planned outage	DNPNU10	0.00	0.00						
De-energisation	De-energisation required planned notification (more than 10 customers)	ENERGEX is requested by a retailer to reconnect or disconnect a customer within a multiple premises compound. Works can only be completed at switchboard and may require notice to all occupants of planned outage	DNPN+10	0.00	0.00						
De-energisation	De-energisation by sticker	De-energisation where ENERGEX stickers the meter	DNS	0.00	0.00						
Meter Investigation	Meter Test	Check that the metering installation is accurately measuring the energy consumed				MIMT1MB	14.12	15.53	MIMT2MB	14.12	15.53
Meter Reconfiguration	Change Tariff	Changes to tariff, that requires meter reprogramming (except for controlled load timing changes)				MRCT1M	52.54	57.79	MRCT2M	105.18	115.70
Meter Reconfiguration	Change Time switch	Changing time switch settings				MRCTS1M	52.54	57.79	MRCTS2M	52.54	57.79

Service Information			Business Hours								
			General			*No CT*			*CT*		
Class	*Service*	*Service Description*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*
Miscellaneous	Wasted Truck Visit	*Wasted truck visit of single crew due to*: installation not ready for connection on or after the date nominated by the Electrical Contractor on the Form 2; customer fails to keep appointment or access not provided as agreed	MSWTV	52.32	57.55						
Miscellaneous	Additional crew	Where additional single crew for a period of up to one hour is required at a service call for health, safety or security reasons	MSAC	104.74	115.21						
Miscellaneous	Locating ENERGEX underground cables	Customer requests assistance from a single crew for a period of up to one hour, in locating ENERGEX's underground cables	MSAPLC	130.95	144.05						
Miscellaneous	Additional Charge - Communications	Additional time required by single crew for a period up to one hour for any service provided to a connection point where communications have been installed	MSCOMS	52.32	57.55						
New Connection	Temporary Connection	Standard temporary connection consisting of a single LV service in which supply location is expected to be removed at a later date				NCT1MB	318.18	350.00	NCT2MB	318.18	350.00
Re-energisation	Re-energisation after Disconnection for Non-Payment	Re-energisation after disconnection as part of a non-payment process				RN$1MB	35.35	38.89	RN$2MB	35.35	38.89
Re-energisation	Re-energisation after Disconnection for Non-Payment (Visual)	Re-energisation after disconnection as part of a non-payment process				RN$V1MB	35.35	38.89	RN$V2MB	35.35	38.89
Re-energisation	Re-energisation (Visual) - No CT (business hours)	Re-energisation				RNV1MB	0.00	0.00	RNV2MB	0.00	0.00
Re-energisation	New Reading Required for Move-In	Meter read on an already energised site prior to occupation of the premises by the customer	RNRM	26.15	28.77						
Re-energisation	Retrospective Move-In	Meter read on an already energised site, following initial occupation of the premises by the customer	RNNR	26.15	28.77						

Service Information			Business Hours								
			General			*No CT*			*CT*		
Class	*Service*	*Service Description*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*
Re-energisation	Retrospective Move-In	Meter read provided on an already energised site, based on a read conducted within the previous six weeks, following initial occupation of the premises by the customer	RNRM	26.15	28.77						
Special Read	Meter Check Read	Reported error in the meter reading. This is used to check the accuracy of the meter reading only. If Retailer requires anything more than a reading (e.g. cerification of meter number, number of dials etc) a Meter Investigation Request should be issued	SRCR	26.15	28.77						
Street Lighting Works	Standard Luminaries Glare Screening - Internal	Supply and installation of internal streetlight baffle. Internal baffle for the B2223, B2224 and Nostalgia/Avenue (decorative) fittings.	SLLGSdl	280.22	308.24						
Street Lighting Works	Adhesive Luminaries Glare Screening	Supply and installation of Internal Adhesive Shield (Kits: Minor - SC 18050, Major - SC 18051)	SLLGAd	123.86	136.25						
Street Lighting Works	Unique Luminaries Glare Screening - External	Supply and installation of external streetlight shield	SLLGUni	953.55	1048.91						
Street Lighting Works	Replacement of standard Luminaries with Aeroscreen units (per streetlight)	Replacement of existing streetlight luminaries with Aeroscreen low glare luminaries	SLAU	292.95	322.24						

Service Information			Business Hours								
			General			*No CT*			*CT*		
Class	*Service*	*Service Description*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*
Supply Abolishment	Supply Abolishment - Simple	Retailer requests the Service Provider to abolish supply at a given Connection Point.	SA1	104.96	115.46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unmetered Supply	Unmetered Supply Connection - connection point not available	Connection of unmetered approved equipment to the network where no connection point exists (i.e. underground mains) (category 2)	NCUMSCN	366.78	403.46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unmetered Supply	Unmetered Supply Disconnection	Recovery of connection to unmetered approved equipment	DNUMS	261.99	288.19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unmetered Supply	Temporary Unmetered Supply	Temporary connection of unmetered approved equipment to an existing low voltage supply at a pole or an underground pillar, e.g. caravans, Defence Forces Recruiting, Blood Bank, etc.	TUMS	261.99	288.19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Service Information			After Hours/Anytime								
			General			**No CT**			**CT**		
Class	*Service*	*Service Description*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*	*Product*	*Price GST Exclusive*	*Price GST Inclusive*
Adds & Alts	Install Meter	Installation of a single new meter (except for a hot water meter)				AAIM1MA / AAIM1MT	41.68	45.85	AAIM2MA / AAIM2MT	116.70	128.37
Callout Charge	Attending Loss of Supply LV - Customer's Installation at Fault	ENERGEX attended LVcustomer's trouble call during business hours and found fault in LV customer's installation (includes tripped safety switch, internal fault, customer overload, etc)	LOSA / LOST	208.15	228.96						
Miscellaneous	Additional crew	Where additional single crew for a period of up to one hour is required at a service call for health, safety or security reasons	MSACA / MSACT	138.76	152.64						
New Connection	U/G Permanent Supply	Supply location is expected to be the final location				NCUP1MA / NCUP1MT	50.02	55.02	NCUP2MA / NCUP2MT	133.38	146.71
New Connection	O/H Permanent Supply	Supply location is expected to be the final location				NCOP1MA / NCOP1MT	50.02	55.02	NCOP2MA / NCOP2MT	133.38	146.71
New Connection	Temporary Connection	Standard temporary connection consisting of a single LV service in which supply location is expected to be removed at a later date				NCT1MA / NCT1MT	828.82	911.70	NCT2MA / NCT2MT	828.82	911.70
New Connection	Temporary in Permanent	Temporary connections at the permanent supply location				NCTP1MA / NCTP1MA	50.02	55.02	NCTP2MA / NCTP2MT	100.03	110.04
Re-energisation	Re-energisation after Disconnection for Non-Payment	Re-energisation after disconnection as part of a non-payment process				RN$1MA / RN$1MT	84.87	93.36	RN$2MA / RN$2MT	84.87	93.36
Re-energisation	Re-energisation after Disconnection for Non-Payment (Visual)	Re-energisation after disconnection as part of a non-payment process				RN$V1MA / RN$V1MT	84.87	93.36	RN$V2MA / RN$V2MT	84.87	93.36
Re-energisation	Re-energisation (Visual) - (business hours)	Re-energisation				RNV1MA / RNV1MT	84.87	93.36	RNV2MA / RNV2MT	84.87	93.36

4. NON-STANDARD EXCLUDED DISTRIBUTION SERVICES

ENERGEX provides a variety of non-standard, variable priced services, including:

- Relocation of ENERGEX assets at customer request;
- Temporary LV service disconnection[14];
- Temporary HV service disconnection;
- Upgrade from Overhead service to Underground service;
- Provision of metering data above minimum regulatory requirements;
- Provision of load profile data where available;
- Coverage of low voltage mains;
- Provision of detailed design for customer requested extension;
- Specification Fees;
- Ratification of illegal connections;
- Emergency recoverable work;
- Conversion to aerial bundled cables;
- Provision of reactive power;
- Provision of higher standard MDP services; and
- Complex supply abolishment.

The above listed services are not considered standard due to the variance in the precise nature of the services being sought. A price will be provided to the customer and/or retailer on application. A description of the service provided is detailed in the table below.

The conditions, including time frames, upon which the requested service will be undertaken by ENERGEX will depend upon the type of work requested and will be subject to commercial negotiation between the parties.

[14] This service is provided during business hours and on an after hours basis

NON-STANDARD EXCLUDED DISTRIBUTION SERVICES DESCRIPTION				
			Business Hours	**After Hours**
	Service Information		***General***	***General***
Class	*Service*	*Service Description*	*Product*	*Product*
Adds & Alts	Relocation of ENERGEX assets at customer request	Where ENERGEX assets are moved at a customer's request	MSREL	MSDNNDA
Miscellaneous	Temporary LV Service Disconnection - no dismantling	Temporary disconnection & reconnection of supply at the service fuse to allow customer or contractor to work close - no dismantling of service required	MSDNNDB	MSDNPDA
Miscellaneous	Temporary LV Service Disconnection - physical dismantling	Temporary disconnection & reconnection of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (e.g. Overhead Service Dropped)	MSDNPDB	MSDNHVA
Miscellaneous	Temporary HV Service Disconnection	Temporary disconnection & reconnection of supply to allow customer or contractor to work close - High Voltage Switching & access is required	MSDNHVB	[redacted]
Miscellaneous	Provision of metering data above minimum regulatory requirements	Provision of metering data by ENERGEX beyond its regulatory requirements as a Meter Data Provider	MSOBD	[redacted]
Miscellaneous	Upgrade from overhead to underground service	Customer requested conversion of existing overhead service to underground service	MSOHtoUG	[redacted]
Miscellaneous	Provision of load profile data where available	Provision of load profile data where available on request by retailer	MSLPD	[redacted]
Miscellaneous	Specification Fees	Fee for service when ENERGEX prepares & issues specifications for customer extension works	MSSF	[redacted]
Miscellaneous	Rectification of illegal connections	Charges for work required as a consequence of illegal connections resulting to damage to the network	MSAPIC	[redacted]
Miscellaneous	Emergency recoverable works	Charges for work carried out by ENERGEX as a result of emergency or third party action.	MSERW	[redacted]
Miscellaneous	Conversion to aerial bundled cables	Bundling of cables which is carried out at the request of another party	MSAPABC	[redacted]
Miscellaneous	Provision of reactive power	Charges for the provision or receipt of reactive power & energy to & from a connection point	MSREAC	[redacted]
Miscellaneous	Provision of detailed design estimate for LV customer requested extension / connection	Applies to customers who have received a preliminary estimate for extension or connection works & seek a detailed estimate / quotation	MSDD	[redacted]
Miscellaneous	MDP services - higher standard	Collection, processing & transfer of higher standard energy data for customers than would otherwise be provided - retailer requested	MEMDP	[redacted]
Supply Abolishment	Supply Abolishment - Complex	Retailer requests the Service Provider to abolish supply at a given Connection Point.	SA2	[redacted]

APPENDIX 1: GLOSSARY

The following is a table of relevant references used throughout this Price Schedule.

Reference	Definition
After Hours	Refers to any time outside business hours
Anytime Hours	Refers to services requested where the Retailer prefers the work to be undertaken within business hours but is willing to pay the after hours fee where necessary in order to speed up completion of the requested service
Business Day	Refers to a day, other than a Saturday, a Sunday or a public holiday in the local authority area where the premises are located
Business Hours	8:00am to 5:00pm on business days
Form 2	A form lodged by the customer's electrical contractor with ENERGEX in relation to all New Connections and Ads and Alts service order types
NMI	National Metering Identifier
NMI Classification	A code that identifies the nature of the flow of electricity at a connection point, classified under the MSATS Procedures: CATS Procedures in terms of the volume of energy consumed
NMI – 'Large'	Refers to a NMI that has a total load of 100 or greater MWh per annum
NMI – 'Small'	Refers to a NMI that has a total load of less than 100MWh per annum
Time (am/pm)	Refers to Queensland time

APPENDIX 2: EXCLUDED LOCATIONS

Suburb	Postcode
Amity	4183
Dunwich	4183
Herring Lagoon	4183
North Stradbroke Island	4183
Point Lookout	4183
Coochiemudlo Island	4184
Karragarra Island	4184
Lamb Island	4184
Macleay Island	4184
Russell Island	4184
Beechmont	4211
Natural Bridge	4211
Numinbah	4211
Numinbah Valley	4211
Austinville	4213
Springbrook	4213
South Stradbroke Island	4216
Pine Creek	4275
Witheren	4275
Allenview	4285
Woodhill	4285
Barney View	4287
Mt Lindesay	4287
Palen Creek	4287
Rathdowney	4287

Suburb	Postcode
Running Creek	4287
Avoca	4306
Linville	4306
Moore	4306
Mt Stanley	4306
Cambroon	4552
Boreen Point	4565
Cooroibah	4565
Cooroibah Heights	4565
Cootharaba	4565
North Shore	4565
Ringtail Creek	4565
Teewah	4565
Anderleigh	4570
Curra	4570
Goomboorian	4570
Kia Ora	4570
Neerdie	4570
Rossmount	4570
Toolara Forest	4570
Wallu	4570
Cooloola Cove	4580
Tin Can Bay	4580
Rainbow Beach	4581
Inskip	4581

ENERGEX Limited

ABN 40 078 849 055

TARIFF SCHEDULE 2009-10

VERSION 2A: JULY 2009

Revised 21 July 2009

CONTENTS

1 INTRODUCTION

The 2009/10 Tariff Schedule outlines *Network Use of System* (NUoS) tariffs, incorporating both *Distribution Use of System* (DUoS) and *Transmission Use of System* (TUoS) tariffs applied by ENERGEX for all customer sites. It also sets out prices for *Excluded Distribution Services* (EDS).

This Tariff Schedule applies from 1 July 2009, or as subsequently revised.

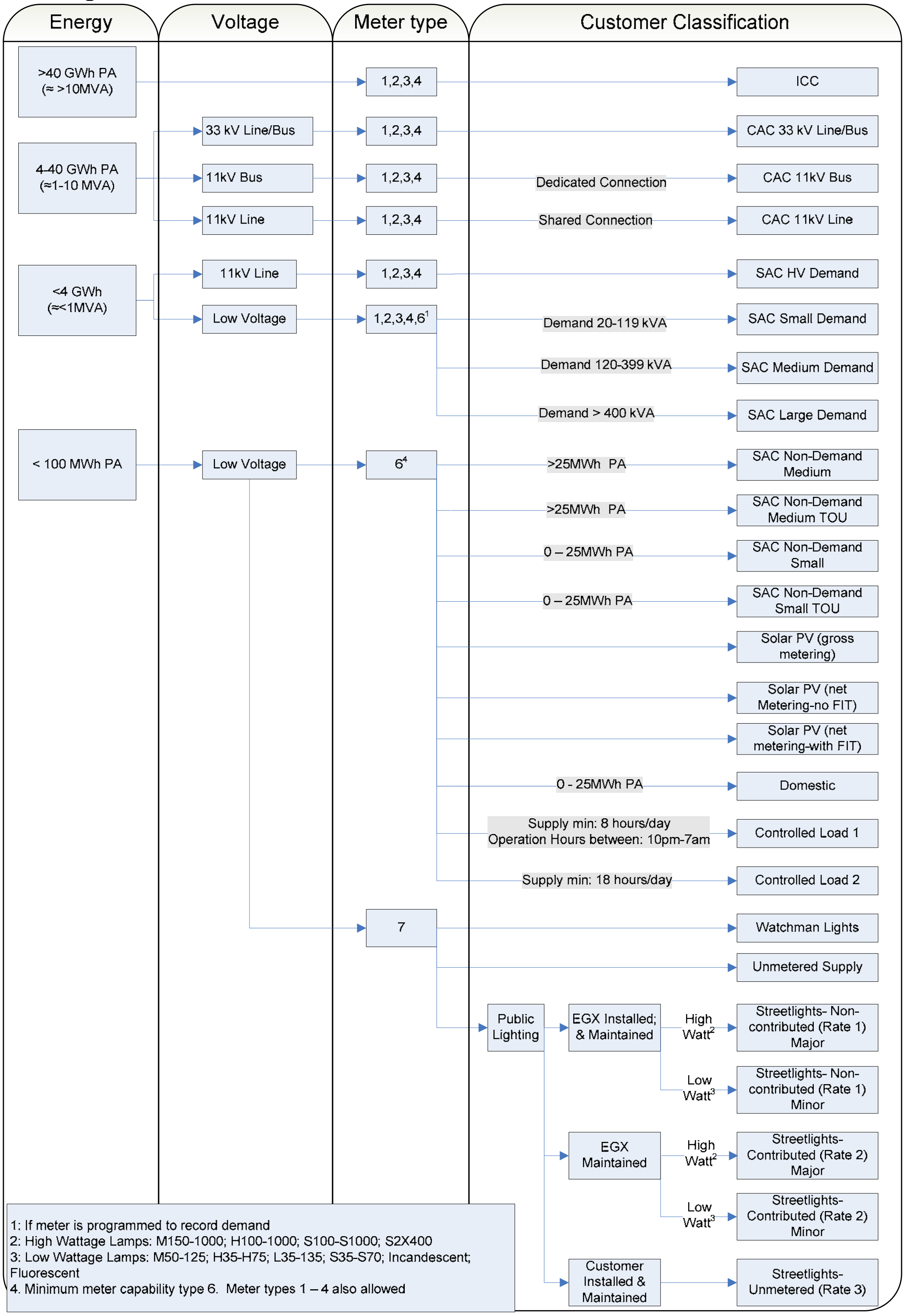
2 PROCEDURE FOR ASSIGNING AND REASSIGNING CUSTOMERS TO TARIFF CLASSSES

Customer allocation to tariff classes is determined based on the following (in order):

1. Energy consumption;
2. Voltage level;
3. Meter type;
4. Demand; and
5. For Unmetered supply, whether the supply is for public lighting or other unmetered supplies.

The application of the above five criteria is summarised in Figure 1.

Figure 1: Assignment of customers to tariff classes



Notes:
There may be exceptions to the application of the first criteria, energy consumption, depending on the nature of a connection.

a. ENERGEX may elect not to apply *ICC* pricing to customers with consumption greater than 40GWh/year where the designation of shared network assets is impractical to achieve accurate pricing.

b. A customer with energy consumption below 40GWh may be classed as an *ICC* where the customer's circumstances mean that the average shared network charge becomes meaningless or distorted.

c. A customer with energy consumption below 4GWh may be classed as *CAC*, where they have a dedicated supply system with significant connection assets or where inequitable treatment of otherwise comparable customers arises from the 4GWh cut-off.

Allocation of an *Embedded Generator* (EG) customer to a network tariff will be made on the same basis as other connections, as explained above. The network tariff will include fixed and variable components. If the customer's demand were to be met entirely by the generator then the levied charge will be only the fixed components.

Allocation of a customer with micro-generation facilities to a network tariff will be made on the same basis as other connections, as explained above. The tariff will include fixed and variable components. Where the customer's load is met entirely by the micro-generation, the charge levied will reflect the fixed tariff components only. Where the customer is able to supply their own load and export excess generation to the grid, a feed-in tariff may be payable to the customer for the amount of energy exported. In any case, no charges will be applied to the energy exported.

ENERGEX calculates site specific tariffs for customers with annual consumption greater than 4GWh. An *Individually Calculated Customer* (ICC) is a customer with energy usage above 40GWh or where the customer's circumstances mean that the average shared network price becomes meaningless or distorted. A *Connection Asset Customer* (CAC) is a customer with energy usage above 4GWh (but less than 40GWh), or if they have a dedicated supply system with significant connection assets or where inequitable treatment of otherwise comparable customers arises from the 4GWh cut-off.

It is the retailer's responsibility to select a suitable tariff that complies with the process for assigning customers to tariff classes as depicted in Figure 1 *Assignment of customers to network tariffs.*

If a request is made by a retailer to change a customer's tariff, these requests are limited to one every 12 months unless agreed to by ENERGEX. Backdating of changes to network tariffs is not ordinarily permitted unless specifically approved by ENERGEX. Applications to change a network tariff should be made in writing by the retailer by completing ENERGEX Form 1634.

From time to time ENERGEX reviews the operation of its tariffs. If it is found that a customer is assigned to an incorrect tariff, the retailer will be notified of any tariff change that ENERGEX makes. If a customer objects to the reassignment, the objection should be notified to ENERGEX in writing by the retailer, identifying the reason for the objection. ENERGEX will undertake a subsequent review of the application applying *Figure 1* above and the approved Pricing Principles Statement (PPS). The retailer will be notified of the outcome as soon as practicable following the review. ENERGEX has the final decision on the correct application of its network tariffs.

ENERGEX applies a tolerance of up to 20 percent around tariff thresholds. This is to mitigate against customers oscillating across tariffs and potentially being repeatedly assigned back and forth between tariffs.

ENERGEX may introduce a new network tariff or make changes to the tariff structure of existing tariffs, in consultation with relevant stakeholders. Retailers will be advised of any such changes.

Where ENERGEX offers voluntary tariffs (eg. tariff trials), the assignment to those tariffs is considered to be at the request of the customer rather than ENERGEX.

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3 NETWORK TARIFFS

3.1 Network Tariffs for Individually Calculated Customers

Network tariffs for *ICCs* are calculated on a site-specific basis and are not published. ENEGEX will provide these site-specific network tariffs directly to the customer and their retailer.

3.2 Network Tariffs for Connection Asset Customers

Network Tariffs for *CAC's* are comprised of a site-specific connection price and an average shared network price. The site-specific components of tariffs for *CAC's* are not published. ENEGEX will provide these site-specific network tariffs directly to the customer and their retailer.
The network tariffs for *CAC's* are outlined in Table 1 below.

Table 1: Network Tariffs for Connection Asset Customers

Network Tariff Code	Network Tariff Description	Tariff Component	Fixed Price ($/ day)	Capacity Price ($/kW/month)	Demand Price ($/kW/month)	Peak Energy Price (c/kWh)	Off-peak Energy Price (c/kWh)
3500	33kV Line/Bus	DUoS	Site Specific	$0.59049	$1.22039	0.221	0.021
		TUoS		$0.50025	-	0.959	0.093
		NUoS		$1.09074	$1.22039	1.180	0.114
		NUoS (GST)		**$1.19981**	**$1.34243**	**1.298**	**0.125**
4000	11kV Bus	DUoS	Site Specific	$0.97100	$2.16772	0.255	0.025
		TUoS		$0.50828	-	0.931	0.093
		NUoS		$1.47928	$2.16772	1.186	0.118
		NUoS (GST)		**$1.62721**	**$2.38449**	**1.305**	**0.130**
4500	11kV Line	DUoS	Site Specific	$1.71645	$3.53782	0.299	0.030
		TUoS		$0.52502	-	0.916	0.092
		NUoS		$2.24147	$3.53782	1.215	0.122
		NUoS (GST)		**$2.46562**	**$3.89160**	**1.337**	**0.134**

N.B. *NUoS* is the sum of *DUoS* and *TUoS*

3.3 Network Tariffs for Embedded Generators

The network tariffs for *EG's* are calculated on a site-specific basis and are not published. ENEGEX will provide these site-specific network tariffs directly to the customer and their retailer.

3.4 Network Tariffs for Standard Asset Customers

Standard Asset Customer (SAC) network tariffs are based on the averages of the shared network prices and the connection prices for the customer. Tariffs for *SAC Demand* and *SAC Non-demand* are outlined below.

3.4.1 Network Tariffs for Demand Metered Standard Asset Customers

The network tariffs for *SAC Demand* customers are included in Table 2 below.

Table 2: Network Tariffs for Demand Metered Standard Asset Customers

Network Tariff Code	Network Tariff Description	Default Distribution Loss Factor	Minimum Chargeable Demand (kW)	Tariff Component	Fixed Price ($/day)	Demand Price ($/kW/ month)	Energy Price (c/kWh)
8000	High Voltage Demand	FLCL	200	DUoS	$27.81458	$5.73413	0.200
				TUoS	$6.74498	$0.89849	1.031
				NUoS	$34.55956	$6.63262	1.231
				NUoS (GST)	**$38.01552**	**$7.29588**	**1.354**
8100	Large Demand	FLCL	400	DUoS	$26.59974	$6.43411	0.199
				TUoS	$10.91524	$1.10716	1.130
				NUoS	$37.51498	$7.54127	1.329
				NUoS (GST)	**$41.26648**	**$8.29540**	**1.462**
8200	Medium Demand	FLCL	120	DUoS	$10.02140	$7.65137	0.203
				TUoS	$3.83334	$1.12485	1.081
				NUoS	$13.85474	$8.77622	1.284
				NUoS (GST)	**$15.24021**	**$9.65384**	**1.412**
8300	Small Demand	FLCL	20	DUoS	$0.95928	$12.40596	0.211
				TUoS	$0.90674	$1.12532	1.081
				NUoS	$1.86602	$13.53128	1.292
				NUoS (GST)	**$2.05262**	**$14.88441**	**1.421**

N.B. *NUoS* is the sum of *DUoS* and *TUoS*

3.4.2 Network Tariffs for Non-Demand Metered Standard Asset Customers

The network tariffs for *SAC Non-demand* customers are included in Table 3 below.

Table 3: Network Tariffs for Non-Demand Metered Standard Asset Customers

Network Tariff Code	Network Tariff Description	Tariff Conditions	Tariff Component	Fixed Price ($/day)	Peak Energy Price (c/kWh)	Off-peak Energy Price (c/kWh)
8600	Business Medium	Over 25,0 00 kWh PA	DUoS	$0.62602	5.196	5.196
			TUoS	$0.48983	1.130	1.130
			NUoS	$1.11585	6.326	6.326
			NUoS (GST)	**$1.22744**	**6.959**	**6.959**
8800	Business Medium TOU	Over 25,000 kWh PA	DUoS	$0.62602	5.749	3.334
			TUoS	$0.48983	1.130	1.130
			NUoS	$1.11585	6.879	4.464
			NUoS (GST)	**$1.22744**	**7.567**	**4.910**
8500	Business Small	0 to 25,000 kWh PA	DUoS	$0.21098	5.834	5.834
			TUoS	$0.04486	1.130	1.130
			NUoS	$0.25584	6.964	6.964
			NUoS (GST)	**$0.28142**	**7.660**	**7.660**
8700	Business Small TOU	0 to 25,000 kWh PA	DUoS	$0.21098	6.055	3.754
			TUoS	$0.04486	1.130	1.130
			NUoS	$0.25584	7.185	4.884
			NUoS (GST)	**$0.28142**	**7.904**	**5.372**
8400	Domestic (Energy Only)	0 to 25,000 kWh PA	DUoS	$0.21098	5.834	5.834
			TUoS	$0.04486	1.130	1.130
			NUoS	$0.25584	6.964	6.964
			NUoS (GST)	**$0.28142**	**7.660**	**7.660**
9000	Controlled Load 1		DUoS	$0.11441	0.300	0.300
			TUoS	$0.02011	0.824	0.824
			NUoS	$0.13452	1.124	1.124
			NUoS (GST)	**$0.14797**	**1.236**	**1.236**
9100	Controlled Load 2		DUoS	$0.11149	1.084	1.084
			TUoS	$0.02110	1.050	1.050
			NUoS	$0.13259	2.134	2.134
			NUoS (GST)	**$0.14585**	**2.347**	**2.347**

N.B. *NUoS* is the sum of *DUoS* and *TUoS*

3.4.3 Network Tariffs for Unmetered Supply including Streetlights

The network tariffs for *Unmetered Supply* and streetlights are included in the Table 4 below.

Table 4: Network Tariffs for Unmetered Supply including Streetlights

Network Tariff Code	Network Tariff Description	Tariff Component	Fixed Price ($/day)	Energy Price (c/kWh)
9250	Streetlights Non contributed (Rate 1) Major	DUoS	$1.07246	3.769
		TUoS	-	1.412
		NUoS	$1.07246	5.181
		NUoS (GST)	**$1.17971**	**5.699**
9200	Streetlights Non contributed (Rate 1) Minor	DUoS	$0.27544	3.769
		TUoS	-	1.412
		NUoS	$0.27544	5.181
		NUoS (GST)	**$0.30298**	**5.699**
9350	Streetlights Contributed (Rate 2) Major	DUoS	$1.03861	3.769
		TUoS	-	1.412
		NUoS	$1.03861	5.181
		NUoS (GST)	**$1.14247**	**5.699**
9300	Streetlights Contributed (Rate 2) Minor	DUoS	$0.16240	3.769
		TUoS	-	1.412
		NUoS	$0.16240	5.181
		NUoS (GST)	**$0.17864**	**5.699**
9400	Streetlights Unmetered (Rate 3)	DUoS	-	3.769
		TUoS	-	1.412
		NUoS	-	5.181
		NUoS (GST)	**-**	**5.699**
9500	Watchman Lights	DUoS	$0.29594	3.769
		TUoS	-	1.412
		NUoS	$0.29594	5.181
		NUoS (GST)	**$0.32553**	**5.699**
9600	Unmetered Supply	DUoS	-	3.769
		TUoS	-	1.412
		NUoS	-	5.181
		NUoS (GST)	**-**	**5.699**

N.B. *NUoS* is the sum of *DUoS* and *TUoS*

3.5 Network Tariffs for Solar PV

The network tariffs for *Solar PV* are included in the Table 5 below.

Table 5: Network Tariffs for Solar PV (GST Inclusive)

Network Tariff Code	Network Charge Description	Tariff Component	Energy Price (c/kWh)
9700	Solar PV (gross metering)	DUoS	0.00
		TUoS	0.00
		NUoS	0.00
9800	Solar PV (net metering)	DUoS	0.00
		TUoS	0.00
		NUoS	0.00
9900	Solar PV (net metering- with FIT)	DUoS	-44.00
		TUoS	0.00
		NUoS	-44.00

4 PERMITTED TARIFF COMBINATIONS

The Permitted Tariff Combinations are included in the Table 6 below.

Table 6: Permitted Tariff Combinations

		HV Demand	Demand Large	Demand Medium	Demand Small	Domestic	Business Small	Business Medium	Business Small TOU	Business Medium TOU	Controlled Load 1	Controlled Load 2	Streetlight - Rate 1 Minor	Streetlight - Rate 1 Major	Streetlight - Rate 2 Minor	Streetlight - Rate 2 Major	Streetlight - Rate 3	Watchman lights	Unmetered Supply	Solar PV Gross	Solar PV Net without FIT	Solar PV Net with FIT
		8000	8100	8200	8300	8400	8500	8600	8700	8800	9000	9100	9200	9250	9300	9350	9400	9500	9600	9700	9800	9900
HV Demand	8000																					
Demand Large	8100																					
Demand Medium	8200																					
Demand Small	8300																					
Domestic	8400																					
Business Small	8500																					
Business Medium	8600																					
Business Small TOU	8700																					
Business Medium TOU	8800																					
Controlled Load 1	9000																					
Controlled Load 2	9100																					
Streetlight - Rate 1 Minor	9200																					
Streetlight - Rate 1 Major	9250																					
Streetlight - Rate 2 Minor	9300																					
Streetlight - Rate 2 Major	9350																					
Streetlight - Rate 3	9400																					
Watchman lights	9500																					
Unmetered Supply	9600																					
Solar PV Gross	9700																					
Solar PV Net without FIT	9800																					
Solar PV Net with FIT	9900																					

5 PRICES FOR EXCLUDED DISTRIBUTION SERVICES

5.1 Prices for Standard Excluded Distribution Services

The prices for Standard Excluded Distribution Services are included in the Table 7 below.

Table 7: Prices for Standard Excluded Distribution Services

SERVICE INFORMATION			Price ($)	
Category	***Service***	***Service Description***	***GST Exclusive***	***GST Inclusive***
Additions & Alterations	Alterations & Additions to Whole Current Metering Equipment	Addition &/or alteration to current metering arrangement including exchange &/or move meter	135.79	149.36
	Overhead Service Replacement, Single phase	To replace an existing overhead service at customer's request. No material change to load	217.79	239.56
	Overhead Service Replacement, multiple phase	To replace an existing overhead service at customer's request. No material change to load	271.59	298.74
Callout charge	Attending Loss of Supply - *LV* Customer's Installation at Fault - BH	ENERGEX attended *LV* customer's trouble call during business hours and found fault in *LV* customer's installation (includes tripped safety switch, internal fault, customer overload, etc)	162.97	179.26
	Attending Loss of Supply - *LV* Customer's Installation at Fault - AH	ENERGEX attended *LV* customer's trouble call after hours and found fault in *LV* customer's installation (includes tripped safety switch, internal fault, customer overload, etc)	215.84	237.42
De-energisation	De-energisation	De-energisation commenced during business hours all instances	Nil*	Nil*
Meter Investigation	Meter Test	Check that the metering installation is accurately measuring the energy consumed	14.12*	15.53*
Meter Reconfigurations	Reconfigure Meter	Adjustment to meter settings due to change in tariff and/or of time settings	54.48	59.92
Meter Read	Special Meter Read	Meter read taken off-cycle all instances	26.15*	28.77*
Miscellaneous	Additional Crew - BH	Where additional single crew for a period up to one hour is required at a service call for health, safety or security reasons during business hours.	108.61	119.47
	Additional Crew - AH	Where additional single crew for a period of up to one hour is required at a service call for health, safety or security reasons after hours.	143.89	158.27
	Site Visit	Where crew attends site & service is unable to be performed, or to provide notification	54.25	59.67

	Locating ENERGEX Underground Cables	Customer requests assistance, from a single crew for a period of up to one hour, in locating ENERGEX's underground cables	135.79	149.36
New Connection	Provision of Temporary Connection – BH	Provision of temporary single LV service in which supply location is expected to be removed at a later date	318.18*	350.00*
	Provision of Temporary Connection - AH	Provision of temporary single LV service in which supply location is expected to be removed at a later date	859.48	945.42
Re-energisation	Re-energisation - BH	Re-energisation commenced during business hours, visual inspection not required	35.35*	38.89*
	Re-energisation - AH	Re-energisation commenced after hours, visual inspection not required	84.87*	93.36*
	Re-energisation (Visual) - BH	Re-energisation commenced during business hours, visual inspection required	Nil*	Nil*
	Re-energisation (Visual) - AH	Re-energisation commenced after hours, visual inspection required	84.87*	93.36*
Street Lighting Work	Streetlight Glare Screening	The supply and installation of glare shields	128.44	141.28
	Replacement of Standard Luminaries with Aero Screen Units (per streetlight)	Replacement of existing streetlight luminaries with aero screen low glare luminaries	303.78	334.15
Supply Abolishment	Supply Abolishment - simple	Retailer requests the service provider to abolish supply at a given connection point	108.84	119.72
Unmetered Supply	Unmetered Supply	Provision of connection services for approved unmetered equipment	271.68	298.84

*Indicates services that are capped by the Department of Mines and energy as per *Electricity Regulation 2006- Schedule 8*

5.2 Prices for Non-Standard Excluded Distribution Services

The Non-Standard Excluded Distribution Services are included in the Table 8 below. These services are offered on a Price on Application (POA) basis.

Table 8: Non-Standard Excluded Distribution Services

SERVICE INFORMATION		
Category	*Service*	*Service Description*
Additions & Alterations	Relocation of ENERGEX Assets at Customer Request	Where ENERGEX assets are moved at customer's request
Design Fee/Deposit	Provision of Detailed Design Estimate for LV Customer Requested Extension/Connection	Applies to LV customers who have received a preliminary estimate for extension or connection works at a single site, and seek a detailed estimate/quotation.
Meter Investigation	Meter Inspection	Inspection is required to check a required or suspected fault
Metering	MDP Services - higher standard	Collection, processing and transfer of higher standard energy data for customers than would otherwise be provided - retailer requested
Miscellaneous	Temporary LV Service Disconnection - no dismantling – BH	Temporary disconnection and reconnection of supply at the service fuse to allow customer or contractor to work close - no dismantling of service required
	Temporary LV Service Disconnection - no dismantling – AH	Temporary disconnection and reconnection of supply at the service fuse to allow customer or contractor to work close - no dismantling of service required
	Temporary LV Service Disconnection - physical dismantling – BH	Temporary disconnection and reconnection of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (eg overhead service dropped)
	Temporary LV Service Disconnection - physical dismantling – AH	Temporary disconnection and reconnection of supply to allow customer or contractor to work close - the service will be physically dismantled or disconnected (eg overhead service dropped)
	Temporary HV Service Disconnection – BH	Temporary disconnection and reconnection of supply to allow customer or contractor to work close - high voltage switching and access is required
	Temporary HV Service Disconnection – AH	Temporary disconnection and reconnection of supply to allow customer or contractor to work close - high voltage switching and access is required
	Provision of Metering Data above Minimum Regulatory Requirements	Provision of metering data by ENERGEX beyond its regulatory requirements as a Meter Data Provider
	Upgrade from Overhead to Underground Service	Customer requested conversion of existing overhead service to underground service
	Specification Fees	Fee for service when ENERGEX prepares and issues specifications for customer extension works
	Rectification of Illegal Connections	Charges for work required as a consequence of illegal connections resulting to damage to the network
	Provision of Load Profile Data where Available	Provision of load profile data where available on request by retailer

	Provision of Reactive Power	Charges for the provision or receipt of reactive power and energy to and from a connection point
	Conversion to Aerial Bundled Cables	Bundling of cables which is carried out at the request of another party
	Emergency Recoverable Works	Charges for work carried out by ENERGEX as a result of emergency or third party action
	Coverage of Low Voltage Mains (eg tiger tails)	Charge where customer requests the line close to a construction site be physically covered to prevent risk of electrocution
	Other Recoverable Works	Customer requested services that would not otherwise have been required for the efficient management of the network, or covered by another service
Street lighting Work	Unique Luminaries Glare Screening - External	Supply and installation of external streetlight shield
Supply Abolishment	Supply Abolishment - complex	Retailer requests the service provider to abolish supply at a given connection point

6 GLOSSARY

Demand Price	This part of the tariff accounts for the actual demand that a customer places on the electricity network. The actual demand levied for billing purposes is the metered monthly maximum demand. The price is applied as a fixed dollars per kW per month.
Capacity-Network	The maximum demand (kW) that the distribution network can provide for at any one time.
Capacity price	This part of the tariff seeks to reflect the costs associated with providing network capacity required by a customer on a long-term basis. It is levied on the basis of either contracted demand or the maximum demand in the previous calendar year. The price is applied as a fixed dollar amount per kW per month.
Connection Asset Customer (CAC)	Typically those customers with electricity consumption greater than 4GWh (but less than 40GWh) per year at a single connection point; or where a customer has a dedicated supply system with significant connection assets.
Connection Point	The point of electrical coupling between the electricity distribution network and a customer's electrical installation. The meter is installed as close a possible to this location.
Controlled Load 1	Specified permanently connected appliances are controlled by network equipment so that supply will be permanently available for a minimum period of 8 hours at the absolute discretion of ENERGEX but usually between the hours of 10:00pm and 7:00am.
Controlled Load 2	Specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18hours per day during time periods set at the absolute discretion of ENERGEX.
Demand	The amount of power required by a consumer at any one time measured in terms of watts (W), kilowatts (kW) or megawatts (MW).
Demand Metered SAC	The customers connection point has a meter installed that is capable of measuring energy consumption (kWh) and demand (kW). This meter records total energy consumption (kWh) and demand over 30 minute periods. A customers demand is the average demand (kW) over the 30 minute period.
Demand Metered Tariff	The tariff has been built to include a demand component so that the customers' actual demand is reflected in the price that they pay for their electricity. The highest demand reading for that month is used to calculate the customers electricity bill.
Distribution Loss Factor	Distribution Loss Factors (DLFs) represent the average electrical energy losses incurred when electricity is transmitted over a distribution network.
Distribution Use of System (DUoS)	The tariff for use of the distribution system.
Embedded Generator	*Embedded Generators* are generally those generators who have a name plate rating greater than 10kW single phase or 30kW three phase.
Energy	The amount of electricity consumed by a consumer over a period of time. Energy is measured in terms of watt hours (Wh), kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Energy Price	This part of the tariff seeks to reflect costs not directly allocated to network drivers and costs that are proportional to the size of the customer. The energy consumption (kWh) for the period, as recorded by the customers meter, is utilised to calculate this part of the tariff charge. This price is applied as a fixed amount (cents) per Kilowatt hour (kWh).
Energy Price-Peak	This price is applicable to those customers who are on a Time of Use tariff. The energy consumption (kWh) during Peak periods (refer to Peak period for Peak period times), as recorded by the customer's meter, is utilised to

	calculate this part of the tariff. This price is applied as a fixed amount (cents) per Kilowatt hour (kWh).
Energy Price- Off-peak	This price is applicable to those customers who are on a Time of Use tariff. The energy consumption (kWh) during Off-peak periods (refer to Off-peak Period for Off-peak Period times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This price is applied as a fixed amount (cents) per Kilowatt hour (kWh).
Excluded Distribution Services (EDS)	Services that are ancillary to the main network services and are regulated under more "light handed" regulatory arrangements by the *QCA*. These services are provided on a fee for service basis.
Excluded Distribution Services (EDS) - Standard	The cost of standard excluded distribution services are recovered based on a fixed fee price.
Excluded Distribution Services (EDS) - Non-standard	These services are considered to be non-standard excluded distribution services due to the variation in scope, timing and complexity of the work requested. The cost of these services are recovered based on the cost of the individual service (i.e. Price on Application).
Fixed Price	The fixed price seeks to reflect the costs associated with customer's dedicated connection assets. The price is applied as a fixed dollar amount per day.
High Voltage	Where a customer takes supply at 11kv or higher.
Individually Calculated Customer (ICC)	Typically those customers with electricity consumption greater than 40GWh per year at a single connection point; or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted.
Major streetlights	Larger, higher wattage streetlights typically used on major roads and are categorised according to lamp size, as per attachment in Appendix 1.
Maximum Demand	The *maximum demand* recorded at a customers individual meter within that month.
Minimum Chargeable Demand	The *minimum chargeable demand* will be applied to customers, for billing purposes, in each month where the metered monthly maximum demand fails to exceed the *minimum chargeable demand* for their tariff code.
Minor streetlights	Smaller, lower wattage streetlights typically used on minor roads and are categorised according to lamp size, as per attachment in Appendix 1.
National Metering Identifier (NMI)	A unique identifier for *connection points* and associated metering points.
Network Use of System (NUoS)	The tariff for use of the distribution and transmission networks. It is the sum of both *Distribution Use of Service* and *Transmission use of Service*.
Non-Demand Metered SAC	The customers connection point has a meter installed that is capable of measuring the total energy consumption (kWh).
Non-Demand Metered Tariff	The tariff is based around a fixed daily component the actual energy (kWh) used by the customer.
Off-peak Period	All hours which are outside of peak period hours.
Peak Period	Meter type 1-4 (*ICC's*, *CAC's* & *SAC demand*): The hours between 7am and 11pm, Monday to Friday. Meter type 6 (SAC Non-demand): The hours between 7am and 9pm, Monday to Friday.
Pricing Principles Statement (PPS)	This document communicates the methodology that is applied to develop and set prices. This is submitted to the QCA on an annual basis. These prices have been developed in accordance with the ENERGEX Pricing Principles

	Statement which is available on the ENERGEX website.
Queensland Competition Authority (QCA)	An independent Statutory Authority that regulates the prices for electricity distribution.
Queensland Government Solar Bonus Scheme for Standard Asset Customers	A program that pays domestic and other small energy customers for the surplus electricity generated from roof-top solar photovoltaic (PV) systems that is exported to the Queensland grid.
Site Specific Price	This charge is calculated specifically for a site and is specific to the individual connection point.
Solar Photovoltaic (Solar PV)	A *Solar Photovoltaic* system uses sunlight to generate electricity for domestic use. The system provides power for the premises with any excess production feeding into the electricity grid.
Standard Asset Customer (SAC)	Generally those customers with an annual electricity consumption below 4GWh per year, whose supply arrangements are consistent across the customer group.
Streetlights – Non-contributed (Rate 1)	This tariff is applicable where the capital costs and maintenance costs of the installation are borne by ENERGEX. The tariff seeks to recover the costs associated with the capital and maintenance of the installation and a contribution towards the shared network. This is an unmetered connection.
Streetlights – Contributed (Rate 2)	This tariff is applicable where the maintenance costs but not the capital costs of the installation are borne by ENERGEX. The tariff seeks to recover the costs associated with the capital and maintenance of the installation and a contribution towards the shared network. This is an unmetered connection.
Streetlights – Unmetered (Rate 3)	This tariff is applicable where the capital and maintenance costs of the installation are not borne by ENERGEX. The tariff therefore only seeks to recover a contribution towards the shared network. This is an unmetered connection.
Time of Use (ToU)	*Time-of-Use* prices take into account when, as well as how much, electricity is used by each consumer. With Time-of-Use, electricity is priced at two levels, depending on the time of day. Prices are lower during off-peak hours and higher during on-peak hours.
Transmission Use of System (TUoS)	The tariff for the use of the transmission network.
Unmetered Supply	A customer who takes supply where no meter is installed at the connection point.
Unmetered Supply Tariff	*Other Unmetered supply* tariff is applicable to unmetered supplies where the customer owns and maintains all assets after the customer connection point. This includes facilities such as public telephones, traffic signals, and public barbecues. ENERGEX only provides connection to the network for these services. The unmetered supply tariff therefore seeks to only recover a contribution towards the shared network.
Watchman lights	Watchman lights are owned, operated and maintained by ENERGEX. The tariff seeks to recover the capital and maintenance costs of the installation, as well as a contribution towards the shared network.

Appendix 1: Streetlight Wattage Classification

Table 1: Minor Streetlight Wattage Classification

Streetlights- Minor Classification	
Streetlight Type	*Wattage Reference Classification*
Mercury Vapour	Less than 150W
Mercury Halide	Less than 100W
Sodium Vapour	Less than 100W
Incandescent	All
Fluorescent	All
Also includes any other non standard or obsolete public lights that would be replaced with any of the above ENERGEX standard minor public lights in accordance with ENERGEX policy.	

Table 2: Major Streetlight Wattage Classification

Streetlights- Major Classification	
Streetlight Type	*Wattage Reference Classification*
Mercury Vapour	Greater than or equal to 150W
Mercury Halide	Greater than or equal to 100W
Sodium Vapour	Greater than or equal to 100W
Also includes any other non standard or obsolete public lights that would be replaced with any of the above ENERGEX standard major public lights in accordance with ENERGEX policy.	

Energex

Tariff Schedule

for the period 1 July 2012 to 30 June 2013

Version 9 11 February 2013

energex

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Version Control

Version	Date	Description
1	07/06/2012	Initial version published on ENERGEX website (excludes 2012-13 Schedule 8 prices)
2	15/06/2012	Table 5 for Schedule 8 capped prices, to show 2011-12 prices instead of 2012-13 AER approved prices (as per previous years). Still excludes 2012-13 Schedule 8 prices, will be updated again once released.
3	29/06/2012	Figure 1 updated for NTC7500; Table 1 and 2 updated for new tariff NTC7500 Solar PV 2 – this will take effect from 10/7/12 and NTC8400 (Residential Flat) updated in line with QLD Government Policy (28/06/12); Terms & Conditions updated for NTC7500.
4	29/06/2012	Table 5 updated to include 2012-13 Schedule 8 Prices
5	09/07/2012	New section added: 3.2 – variations between regulatory years and Section 3.3, Terms and Conditions updated for SAC Demand.
6	02/08/2012	Table 5 updated – re-energisations categories
7	16/08/2012	Table 5 updated – numbering for notes updated
8	17/10/2012	Service Descriptions for Quoted Services Product Codes updated in Appendix 3.
9	11/02/2013	Updated to reflect AER approved prices for NTC8400 (in line with QLD Government Direction 31/1/13)

Energex Limited trading as Energex
ABN 40 078 849 055
26 Reddacliff Street
NEWSTEAD QLD 4006

http://www.energex.com.au

Requests and inquiries concerning this document should be addressed to:

Pricing Manager
Energex
GPO Box 1461
BRISBANE QLD 4001

Table of Contents

1 Introduction

The Tariff Schedule for 2012-13 outlines Energex's tariffs for both Standard Control Services (SCS) and Alternative Control Services (ACS).

For SCS, the Network Use of System (NUOS) tariffs are provided, which incorporates both the Distribution Use of System (DUOS) charges and Designated Pricing Proposal Charges (DPPC)[1].

For ACS, charges for the provision of street lights, fee-based services and quoted services are provided. Quoted services are performed on a price on application basis.

This Tariff Schedule also provides information on how Energex assigns customers to tariff classes and the internal review process which is undertaken if an objection is raised.

This Tariff Schedule applies from 1 July 2012, or as subsequently revised.

For more information on network pricing please refer to Energex's 2012-13 Pricing Proposal[2].

[1] Designated Pricing Proposal Charges (DPPC) previously referred to as Transmission Use of System (TUOS)

[2] The ENERGEX Pricing Proposal can be downloaded at http://www.energex.com.au/about-us/network-regulation-and-pricing/network-prices

2 Assigning and Reassigning customers to tariff classes

2.1 Standard Control Services (SCS)

For SCS, the following Energex tariff classes apply:

- Individually Calculated Customer (ICC)
- Connection Asset Customer (CAC) – 33kV
- CAC – 11kV Bus
- CAC – 11kV Line
- Embedded Generators (EG)
- Standard Asset Customer (SAC) Demand
- SAC Non-demand

Each customer for SCS is a member of at least one tariff class. Energex's customer assignment to tariff classes is based on assessment of one or more of the following criteria:

a) energy consumption and/or demand; and

b) voltage level.

In addition to the above, the following guidelines apply:

- a change in connection voltage means that the connection is treated as if it was a new connection;
- customers are generally only allowed one requested tariff change per 12 month period;
- for customers with demand/energy levels which fluctuate, Energex may apply a tolerance limit of up to 20 per cent around tariff thresholds to mitigate frequent tariff reassignment;
- allocation of a customer with micro-generation facilities to a tariff will be made on the same basis as other connections;
- where a new tariff is applied to a customer, it is standard practice to apply the tariff from the next billing period; and
- for new connections with no previous load history, the default tariff is based on their expected energy usage, supply voltage and meter type.

A pictorial representation of the process for assignment to tariff class for SCS is outlined in Figure 1. Further information on tariff assignment and reassignment is provided in Energex's 2012-13 Pricing Proposal.

If a customer objects to a proposed classification or reclassification, Energex will follow the internal procedure for reviewing objections (as outlined in Appendix 5).

Figure 1 Assignment of customers to tariff classes – SCS (Load customers)

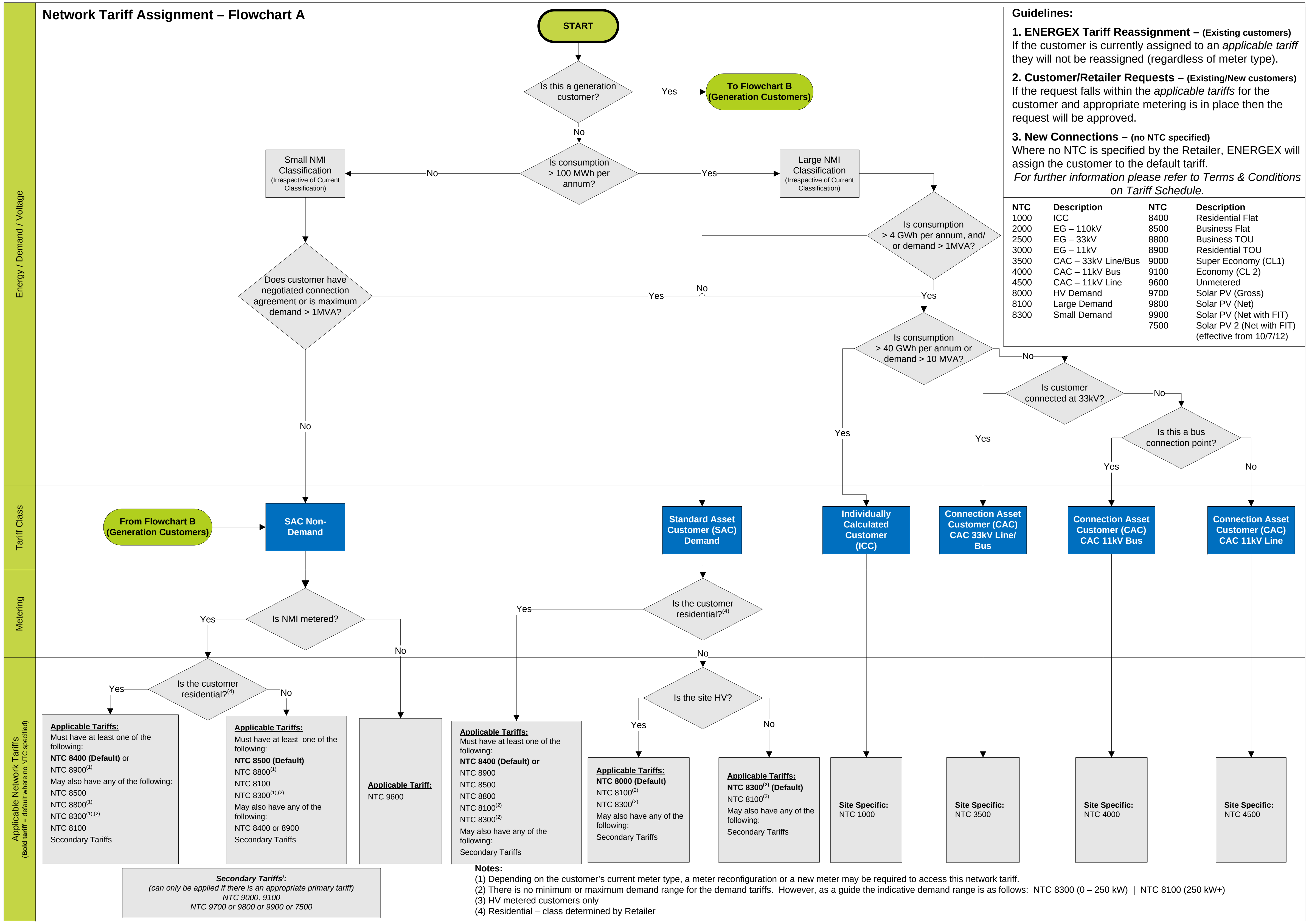
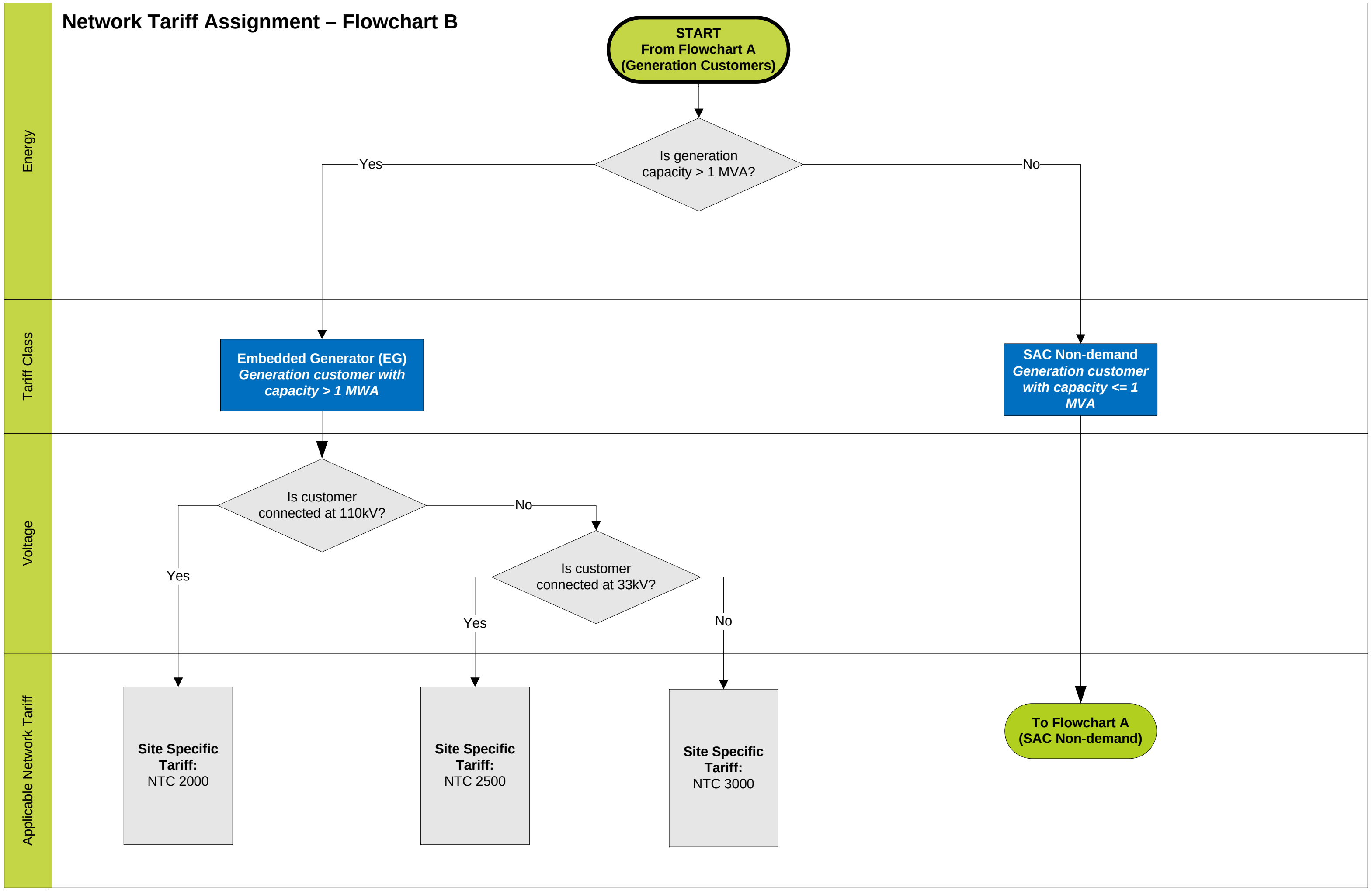


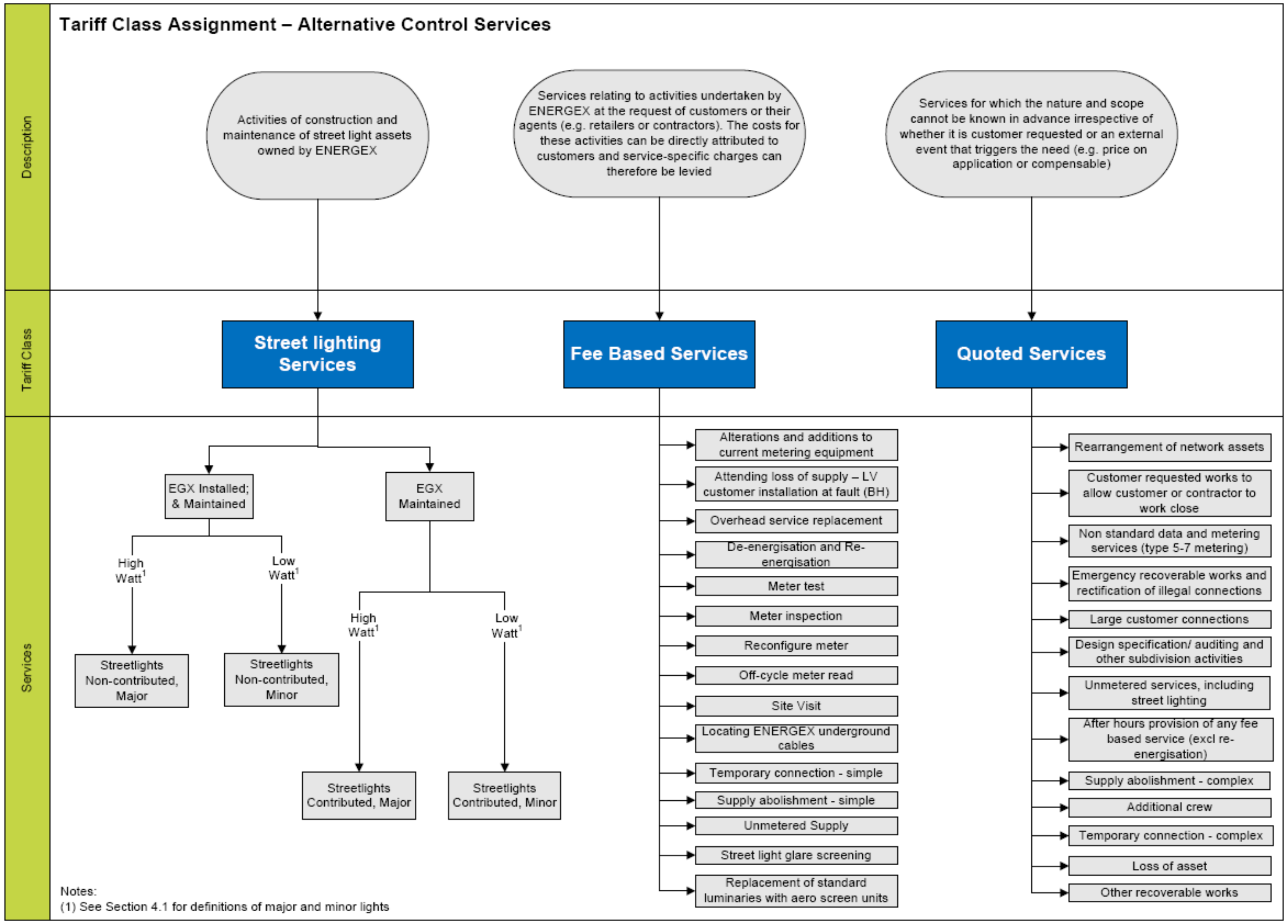
Figure 2 Assignment of customers to tariff classes – SCS (Generation)



2.2 Alternative Control Services (ACS)

The assignment of customers to an ACS tariff is based on the type of service required. Figure 3 outlines the ACS tariff classes and service types.

Figure 3 Assignment of customers to tariff classes – ACS



3 Network Tariffs – Standard Control Services

3.1 2012-13 Tariffs

Network tariffs are comprised of both:

- DUOS tariffs – which relate to the network charges incurred for use of the Energex distribution network; and
- DPPC – which relate to the network charges incurred for use of the Powerlink transmission network.

The 2012-13 DUOS and DPPC tariffs for SCS are provided in Table 1.

The NUOS tariff represents the sum of DUOS and DPPC. This is the total network tariff that may be represented on a customer's bill. The NUOS tariffs for SCS are provided in Table 2.

On the 28 June 2012 and 31 January 2013, Energex received directions under section 115 of the Government Owned Corporations Act 1993 in relation to the charging of Network Tariff 8400.

Table 1 2012-13 DUOS and DPPC tariffs for SCS

Tariff Class	Tariff Description	Network Tariff Code	DUOS Charges[a]							DPPC Charges[a]					
			Fixed ($/day)	Capacity ($/kW/ month)	Demand ($/kW/ month)	Volume Flat (c/kW.h)	Volume Off Peak (c/kW.h)	Volume Shoulder (c/kW.h)	Volume Peak (c/kW.h)	Fixed ($/day)	Demand ($/kW/ month)	Volume Flat (c/kW.h)	Volume Off Peak (c/kW.h)	Volume Shoulder (c/kW.h)	Volume Peak (c/kW.h)
ICC	ICC	1000	Tariffs for ICC customers are confidential. These will be provided directly to the customer and their Retailer.												
CAC 33kV Line/Bus	CAC 33kV Line/Bus	3500	Site Specific	1.063	2.596		0.058		0.073	Site Specific	1.112		0.133		0.133
CAC 11kV Bus	CAC 11kV Bus	4000		2.062	4.202		0.052		0.075		1.112		0.133		0.133
CAC 11kV Line	CAC 11kV Line	4500		2.727	5.921		0.053		0.074		1.112		0.133		0.133
EG's	EG – 33kV	2500	Site Specific	1.063	2.596		0.058		0.073	Site Specific	1.112		0.133		0.133
	EG – 11kV	3000		2.727	5.921		0.053		0.074		1.112		0.133		0.133
SAC Demand	HV Demand	8000	39.08		9.948	0.071				10.12	2.251	0.947			
	Large Demand	8100	18.86		13.718	0.071				10.12	2.251	0.947			
	Small Demand	8300	4.76		15.429	0.071				10.12	2.251	0.947			
SAC Non-demand	Business Flat	8500/8600[b]	0.37			8.469				0.24		1.619			
	Business ToU	8800/8700[c]	0.37				6.922		8.471	0.24			1.461		1.788
	Solar PV (gross)	9700													
	Solar PV (net)	9800													
	Solar PV (net with FIT)	9900				-44.000									
	Solar PV 2 (net with FIT)[d]	7500				-8.000									
	Residential Flat[e]	8400	0.18802 0.09198[f]			8.728				0.07		1.472			
	Residential ToU	8900	0.28				6.309	9.566	19.771	0.07			1.187	1.803	3.754
	Super Economy (controlled load 1)	9000				3.475						0.637			
	Economy (controlled load 2)	9100				6.302						1.154			
	Unmetered	9600				6.836						1.252			

a. All tariffs are GST exclusive.
b. Customers on Network Tariff Code 8600 will be transitioned to NTC 8500 by 31/12/12.
c. Customers on Network Tariff Code 8700 will be transitioned to NTC 8800 by 31/12/12.
d. Effective from 10/7/12.
e. This tariff is subject to Shareholding Minister's Directions dated 28 June 2012 and 31 January 2013.
f. Only chargeable according to the terms of the Shareholding Minister's Directions dated 31 January 2013.

Table 2 2012-13 NUOS tariffs for SCS

Tariff Class	Tariff Description	Network Tariff Code	NUOS Charges[a]						
			Fixed ($/day)	Capacity ($/kW/ month)	Demand ($/kW/ month)	Volume Flat (c/kW.h)	Volume Off Peak (c/kW.h)	Volume Shoulder (c/kW.h)	Volume Peak (c/kW.h)
ICC	ICC	1000	Tariffs for ICC customers are confidential. These will be provided directly to the customer and their Retailer.						
CAC 33kV	CAC 33kV Line/Bus	3500	Site specific	1.063	3.708		0.191		0.206
CAC 11kV Bus	CAC 11kV Bus	4000		2.062	5.314		0.185		0.208
CAC 11kV Line	CAC 11kV Line	4500		2.727	7.033		0.186		0.207
EG's	EG – 33kV	2500	Site specific	1.063	3.708		0.191		0.206
	EG – 11kV	3000		2.727	7.033		0.186		0.207
SAC Demand	HV Demand	8000	49.20		12.199	1.018			
	Large Demand	8100	28.98		15.969	1.018			
	Small Demand	8300	14.88		17.680	1.018			
SAC Non-demand	Business Flat	8500/ 8600[b]	0.61			10.088			
	Business ToU	8800/ 8700[c]	0.61				8.383		10.259
	Solar PV (gross)	9700							
	Solar PV (net)	9800							
	Solar PV (net with FIT)	9900				-44.000			
	Solar PV 2 (net with FIT)[d]	7500				-8.000			
	Residential Flat[e]	8400	0.25802 0.09198[f]			10.200			
	Residential ToU	8900	0.35				7.496	11.369	23.525
	Super Economy (controlled load 1)	9000				4.112			
	Economy (controlled load 2)	9100				7.456			
	Unmetered	9600				8.088			

a. All tariffs are GST exclusive. NUOS = DUOS + DPPC
b. Customers on Network Tariff Code 8600 will be transitioned to NTC 8500 by 31/12/12.
c. Customers on Network Tariff Code 8700 will be transitioned to NTC 8800 by 31/12/12.
d. Effective from 10/7/12.
e. This tariff is subject to Shareholding Minister's Directions dated 28 June 2012 and 31 January 2013.
f. Only chargeable according to the terms of the Shareholding Minister's Directions dated 31 January 2013.

3.2 Variations between regulatory years 2011-12 and 2012-13

Energex has recently conducted a review of the existing network tariffs for standard asset customers (SAC). The various changes proposed for 2012-13, as outlined below, are designed to:

- support more specific pricing signals for residential customers through the introduction of a voluntary TOU tariff structure which more adequately reflects the cost of network augmentation thereby assisting in the management of peak demand;
- provide a more robust suite of network tariffs to aid customer understanding and simplify tariff application
- removal of fixed charges for super economy and economy tariffs; and
- enable market efficiency under the new Network plus Retail (N+R) methodology by supporting a 1:1 mapping of network tariffs to notified tariffs.

Table 3 Tariff Changes for 2012-13

Old Tariff	Revised Tariff
New	8900 – Residential TOU
8500 – Business Small – Flat 8600 – Business Medium - Flat[1]	Combined into one tariff: 8500 – Business Flat
8700 – Business Small – TOU 8800 – Business Medium - TOU[2]	Combined into one tariff: 8800 – Business TOU
8200 – Demand Medium	Network tariff removed – all existing customers transferred to Demand Small or Demand Large.

[1] Customers on Network Tariff Code 8600 will be transitioned to NTC 8500 by 31/12/12.
[2] Customers on Network Tariff Code 8700 will be transitioned to NTC 8800 by 31/12/12.

3.3 Terms and Conditions

The Terms and Conditions relating to the SCS tariffs are outlined below.

Energex will apply the rules outlined in Table 3 below, when assigning network tariffs. Whilst Energex may undertake periodic reviews, Energex does not constantly monitor tariffs to ensure they are the most appropriate tariff.

In the event that a customer/Retailer believes a more appropriate tariff is available for the customer, the Retailer should request Energex to change the tariff. This change is dependant upon the necessary metering being installed. Except with Energex's agreement, tariff changes will become effective from the most recent actual read or at completion of field work required to install appropriate meter. Only one free change per year is allowed, thereafter, a charge may apply.

For additional explanation regarding the tariffs please refer to Energex's 2012-13 Pricing Proposal.

Table 4 Terms and conditions for standard control service tariffs

Tariff Class	Tariff	NTC	Description/Tariff Conditions
ICC	ICC	1000	ICC tariffs apply to customers with electricity consumption **greater than 40 GW.h per year** at a single connection point; or where the customers demand is greater than or equal to 10 MVA; or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted. ICC tariffs are site specific and will be provided directly to the customer and/or the Retailer. ▪ The DPPC applies to the volume of energy delivered to the nominated Transmission Connection Point. For ICCs, the metered quantity at the customer's site will be adjusted by the given Distribution Loss Factor (DLF) to calculate the total DPPC. ▪ The nominated capacity is either the contracted demand or the maximum demand in the previous calendar year. ▪ The DUOS demand price applies to the actual maximum demand value recorded per month.
CAC 33kV	CAC 33kV	3500	CAC tariffs applies to customers with electricity consumption **greater than 4 GW.h (but less than 40 GW.h) per year** at a single connection point; or where demand is greater than or equal to 1 MVA at a single connection point; or where the customer has a dedicated supply system with significant connection assets; or where the customer has contributed to their dedicated connection assets. The fixed charges for CACs are site specific and will be provided directly to the customer and/or the Retailer. ▪ The nominated capacity is either the contracted demand or the maximum demand in the previous calendar year. ▪ The DUOS demand price applies to the actual maximum demand value recorded each month.
CAC 11kV Bus	CAC 11kV Bus	4000	
CAC 11kV Line	CAC 11kV Line	4500	
EG	EG 33kV	2500	In line with the Energy Networks Association (ENA) classification, Embedded Generators (EGs) are generally those generators with an installed capacity as follows:

<table>
<tr><th>Tariff Class</th><th>Tariff</th><th>NTC</th><th>Description/Tariff Conditions</th></tr>
<tr><td></td><td>EG 11kV</td><td>3000</td><td>▪ Medium: 1 - 5 MVA (LV or HV) or < 1 MVA (HV); and
▪ Large: > 5 MVA.
Tariffs for connection and access services for Medium and Large EGs will be developed on a similar basis to site-specific customers. This is due to the nature of connections, which are typically non-standard and may require additional embedded generator protection system upgrades.</td></tr>
<tr><td rowspan="3">SAC Demand</td><td>HV Demand</td><td>8000</td><td>This tariff is available for customers connected at HV with consumption below 4GW.h per annum, and demand up to 1000 kW.
This network tariff is not available to customers who have non-standard or significant connection assets provided by Energex.</td></tr>
<tr><td>Large Demand</td><td>8100</td><td rowspan="2">These tariffs apply to customers connected at LV with consumption below 4GW.h per annum, and demand up to 1000 kW.
Customers with consumption less than 100 MW.h can choose to access this tariff on a voluntary basis.
The Energex demand tariffs are <u>self selecting</u> - it is the responsibility of the customer/Retailer to select the most appropriate tariff. As a guide the following demand ranges are provided:
▪ Small Demand: 0 – 275 kW
▪ Large Demand: 250 - 1000 kW.
Where the customer/Retailer does not select a tariff and in the absence of historical demand information (eg. for new customers) the customer will be assigned to Small Demand. Refer to section 2.1.
Business customers with consumption > 100 MW.h must be on a demand tariff. However, if existing metering is not programmed to provide a demand read, ENEGEX will apply another appropriate business tariff until such time as the metering is upgraded.</td></tr>
<tr><td>Small Demand</td><td>8300</td></tr>
</table>

Tariff Class	Tariff	NTC	Description/Tariff Conditions
SAC Non-Demand[1]	Business Flat	8500	This tariff applies to business customers with consumption **less than 100 MW.h per annum**.
	Business ToU	8800	This tariff applies to business customers with consumption **less than 100 MW.h per annum** with a ToU capable meter.
	Solar PV	9700 9800 9900 7500	The solar bonus scheme applies to SACs who consume **less than 100 MW.h per annum**. The Queensland Government sets the feed-in tariff rate (per kW.h) for NTC9900 and NTC7500, to be paid for the excess energy generated. For further information refer to The Office of Clean Energy. Solar PV tariffs can only be applied if there is an appropriate primary tariff at the NMI.
	Residential Flat	8400	**Default** tariff for residential customers, and can not be used in conjunction with residential ToU (8900). Customers with the same tariff assigned to multiple meters will have the consumption across each meter aggregated for billing purposes.
	Residential ToU	8900	This is a voluntary tariff for residential customers, regardless of their size. Customers must have a ToU capable meter to access this tariff and can not use this tariff in conjunction with residential flat (8400). Customers with the same tariff assigned to multiple meters will have the consumption across each meter aggregated for billing purposes.
	Super Economy (controlled load 1)	9000	Specified permanently connected appliances are controlled by network equipment so that supply will be permanently available for a minimum period of 8 hours at the absolute discretion of Energex but usually between the hours of 10:00pm and 7:00am.
	Economy (controlled load 2)	9100	Specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Energex.
	Unmetered	9600	Use of system charge (conveyance of electricity) for all unmetered supplies (eg. street lighting, watchman lighting, public barbeques, telephones, traffic signals)

[1] Small Business customers may also have a residential tariff at their NMI (noting customers cannot have both residential flat and residential ToU on the same NMI), provided there is also a Business tariff.

3.4 kV.A Adjustment for large customers

Energex introduced kV.A tariffs for ICC and CAC customers from 1 July 2010. Network charges for ICC and CAC customers are initially calculated using the existing kW based approach. The demand and capacity charges are then adjusted up or down by a relative amount based on the difference between the customers's measured power factor and the power factor neutral point. This methodology is described further in Appendix 1.

The power factor adjustment methodology is a transitional method to help customers understand the concept of kV.A and the impact of kV.A on the network and network charges.

From 1 July 2012, the power factor adjustment will be increased to provide a stronger kV.A price signal. This will provide an additional incentive for customers with a poor power factor to improve and is more cost reflective. Energex intends to move to a straight kV.A tariff, reflective of current practices in other Australian jurisdictions, from July 2013.

4 Network Tariffs – Alternative Control Services

4.1 Street light services

Street light services covered in ACS relate to the provision, construction and maintenance of street light assets owned by Energex. The ACS prices for street light services are included in Table 4.

Table 5 Prices for street light services

Streetlight Service[2]	Network Tariff Code	2012–13 Price[1] ($ per light per day)
Major non-contributed	9250	1.01
Major contributed	9350	0.27
Minor non-contributed	9200	0.41
Minor contributed	9300	0.11

Notes:

1. All prices are exclusive of GST.
2. Definitions of minor and major lamps is provided in the glossary under *Street Lights*
3. The use of system charge (conveyance of electricity) is a standard control service (included in Tables 1 and 2).

The applicable terms and conditions for each street light service are based on the following principles:

- the contributed street light tariff only applies where the capital cost of the street light has been paid upfront by the customer or their agent;
- at the conclusion of the street light's standard asset life, the non-contributed tariff will apply due to Energex being responsible for the replacement;
- where Energex has supplied the street light and the capital cost has been paid upfront by the customer, the contributed street light tariff will apply for the minimum period specified in the tariff's terms and conditions; and
- where the capital cost of the street light has been funded by Energex and no upfront payment made, whether the initial asset construction or replacement of an asset, the non-contributed street light tariff applies.

4.2 Fee-based services

Fee-based services relate to activities undertaken by Energex at the request of customers or their agents (e.g. Retailers or contractors). The costs for these activities can be directly attributed to customers and service-specific charges can therefore be levied. The prices for fee-based services are included in Table 5 below.

For a full list of fee based services and product codes refer to Appendix 2.

Table 6 Summary of Prices for commonly used Fee-based services

Fee-based service[1]	**2012-13 Price[2] ($ per service)**
Alterations and additions to current metering equipment	101.61
Attending loss of supply – low voltage customer installation at fault – business hours	113.50
Overhead service replacement – single phase	310.73
Overhead service replacement – multiple phase	366.04
De–energisation[3]	Nil
Meter test[3]	15.36
Meter inspection	90.82
Reconfigure meter	75.30
Off–cycle meter read	8.48
Site visit	65.22
Locating Energex underground cables	n/a
Temporary connection – simple[3]	347.64
Re–energisation – business hours[3]	Nil
Re–energisation non–payment – business hours[3]	38.55
Re–energisation – after hours[3]	92.64
Supply abolishment - simple	351.93
Unmetered supply	155.32
Street light glare screening	150.11
Replacement of standard luminares with aero screen units (per street light)	347.02

Notes:
1. A full list of fee based services and product codes can be found in Appendix 2.
2. All prices are exclusive of GST.
3. Services are subject to Schedule 8 of the Queensland Electricity Regulation 2006, which either caps the price or sets the price to nil.

4.3 Quoted Services

Quoted services are services for which the nature and scope cannot be known in advance irrespective of whether the service is customer requested or an external event triggers the need. A description of each service and the product codes which apply are included in Appendix 3. These services are offered on a Price on Application (POA) basis.

Table 7 Quoted service list

Quoted Service	2012-13 Price ($ per service)
Rearrangement of network assets	POA
Customer requested works to allow customer or contractor to work close	POA
Non standard data and metering services (type 5-7 metering)	POA
Emergency recoverable works and rectification of illegal connections	POA
Large customer connections	POA
Design specification/auditing and other subdivision activities	POA
Unmetered services, including street lighting	POA
After hours provision of any fee-based service (excl re-energisation)	POA
Supply abolishment - complex	POA
Additional crew	POA
Temporary connection - complex	POA
Loss of asset	POA
Other recoverable work	POA

5 Watchman Lights

The provision of watchman lights consists of two fees:

1. SCS - a volume charge for the conveyance of electricity to watchman lights (refer to section 3.1 above, unmetered), charged at a c/kW.h.

2. Unregulated service - a fee for the capital outlay, operations and maintenance associated with watchman lights. It is charged at $ per light per day and is shown in the Table 7, below.

Table 8 Prices for watchman lights

Service	Network Tariff Code	2012–13 Price[1] ($ per light per day)
Provision of watchman lights	9500	0.48

Notes:

1. All prices are exclusive of GST.
2. This is an unregulated service

6 Glossary

6.1 Abbreviations

Term	Definition
ACS	Alternative Control Service
AER	Australian Energy Regulator
ATMD	Anytime Maximum Demand
c/kW.h	cents per Kilowatt hour
CAC	Connection Asset Customers
CPI	Consumer Price Index
DPPC	Designated Pricing Proposal Charges (previously known as TUOS)
DUOS	Distribution Use of System
ICC	Individually Calculated Customers
kV.A	Kilovolt Amperes
NUOS	Network Use of System
POA	Price on Application
SAC	Standard Asset Customer
SCS	Standard Control Services
TUOS	Transmission Use of System

6.2 Definitions

Term	Definition
After Hours (A/H)	Anytime outside of business hours
Alternative Control Service	This service class includes the provision, construction and maintenance of street lighting assets, and fee-based and quoted services.
Anytime (Any)	At the Retailer's request, the work is performed within business hours to speed up the completion, and, where necessary after hour fees are charged.
Anytime Maximum Demand (ATMD)	This is the maximum demand recorded at anytime. It can be used to indicate the maximum demand that occurs anytime within a specified time period such as a 12 calendar month period or a specific month.
Business Hours (B/H)	Monday to Friday, 8am to 5pm.

Term	Definition
Capacity charge	This part of the tariff seeks to reflect the costs associated with providing network capacity required by a customer on a long-term basis. It is levied on the basis of either contracted demand or the maximum demand in the previous calendar year. The charge is applied as a fixed dollar amount per kW per month.
Capacity - Network	The maximum demand (kW) that the distribution network can provide for at any one time.
Charging Parameter	The constituent elements of a tariff (as per the *Rules* definition).
Common Service	A service that ensures the integrity of a distribution system and benefits all Distribution Customers and cannot reasonably be allocated on a locational basis.
Connection Asset Customer (CAC)	Typically, those customers with electricity consumption greater than 4GW.h (but less than 40GW.h) per year at a single connection point; or where demand is greater than or equal to 1 MVA; or where a customer has a dedicated supply system with significant connection assets or the customer has contributed to their dedicated connection assets.
Connection Asset (Contributed or Non-contributed)	Related to building connection assets at a customer's premises as well as the connection of these assets to the distribution network. Connection assets can be contributed (customer funded, then gifted to Energex) or non-contributed (Energex funded).
Connection Point	The point of electrical coupling between the electricity distribution network and a customer's electrical installation. The meter is installed as close a possible to this location.
Controlled Load 1	Refer to Super Economy
Controlled Load 2	Refer to Economy
Demand	The amount of electricity energy being consumed at a given time measured in either watts (W) or volt amperes (VA). The difference between the two is the power factor.
Demand Metered SAC	The customer's connection point has a meter installed that is capable of measuring energy consumption (kW.h) and demand (kW). This meter records total energy consumption (kW.h) and demand over 30 minute periods. A customer's demand is the average demand (kW) over the 30 minute period.
Demand Metered Tariff	The tariff has been structured to include a demand component so the customer's actual demand is reflected in the price they pay for their electricity. The highest demand reading for that month is used to calculate the customer's electricity bill.
Demand Charge	This part of the tariff accounts for the actual demand a customer places on the electricity network. The actual demand levied for billing purposes is the metered monthly maximum demand. The charge is applied as a fixed dollar per kW per month.
Distribution Cost of Supply (DCOS) Model	The Energex model used to allocate costs approved by the AER to the various tariff classes.

Term	Definition
Distribution Loss Factor (DLFs)	These represent the average electrical energy losses incurred when electricity is transmitted over a distribution network.
Distribution Use of System (DUOS)	This refers to the network charges for the use of the distribution network.
Designated Pricing Proposal Charge (DPPC)	Refers to the charges incurred for use of the transmission network; previously referred to as Transmission Use of System (TUOS).
Economy (controlled load 2)	Specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Energex. Refer to Appendix 6.
Embedded Generator (EG)	In line with the Energy Networks Association (ENA) classification, Embedded Generators (EGs) are generally those generators with an installed capacity as follows: Medium: 1-5 MW (LV or HV) or <1MW (HV) Large: > 5MW
Energy	The amount of electricity consumed by a consumer (or all customers) over a period of time. Energy is measured in terms of watt hours (W.h), kilowatt hours (kW.h), megawatt hours (MW.h) or gigawatt hours (GW.h).
Fixed Charge	The fixed charge seeks to reflect the costs associated with customer's dedicated connection assets. The charge is applied as a fixed dollar amount per day.
High Voltage (HV)	Refers to the 11kV or above network.
Individually Calculated Customer (ICC)	Typically those customers with electricity consumption greater than 40GW.h per year at a single connection point; or where the customers demand is greater than or equal to 10 MVA; or where a customer's circumstances mean that the average shared network charge becomes meaningless or distorted.
kV.A	Kilovolt Amperes, which is a measure of the apparent power being consumed and is used to measure demand. One kV.A equals 1,000 Volt Amperes.
Low Voltage (LV)	Refers to the sub-11 kV network
Maximum Allowable Revenue (MAR)	The maximum revenue which can be recovered through tariffs for the regulatory year.
Maximum Demand	The maximum demand recorded at a customer's individual meter or the maximum demand placed on the electrical distribution network system at any time or at a specific time or within a specific time period, such as a month. Maximum demand is an indication of the capacity required for a customer's connection or the electrical distribution network.
Micro Generator	AS4777 compliant generators with an installation size of less than 10kW (single phase) or 30kW (three phase) connected to the LV network.

Term	Definition
Market Settlement and Transfer Solution (MSATS)	The central repository for Standing Data for all NMIs in contestable markets.
National Electricity Market (NEM)	The interconnected electricity grid covering Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory.
National Metering Identifier (NMI)	A unique number assigned to each metering installation.
Network Use of System (NUOS)	The tariff for use of the distribution and transmission networks. It is the sum of both Distribution Use of System (DUOS) and Designated Pricing Proposal Charge (DPPC).
Non-demand Metered SAC	The customer's connection point has a meter installed that is capable of measuring the total energy consumption (kW.h).
Non-demand Metered Tariff	The tariff is based around a fixed daily component and the actual energy (kW.h) used by the customer.
Off-peak Period	All hours which are outside of Peak Period and Shoulder hours.
Peak Period	Meter type 1-4 (ICC, CAC & SAC demand): The hours between 7am and 11pm, Monday to Friday. Meter type 6 (SAC Non-demand - Business): The hours between 7am and 9pm, Monday to Friday. Meter type 6 (SAC Non-demand - Residential): The hours between 4pm and 8pm, Monday to Friday.
Power Factor	Power factor, is the ratio of kW to kV.A, and is a useful measure of the efficiency in the use of the network infrastructure. The closer to one the power factor, the more efficient the network assets are utilised. Power Factor = kW/kV.A
Price Path	Outlines the escalation factors to be applied to the initial price over the regulatory control period.
Primary Tariff	A tariff that is capable of existing by itself against a NMI.
Queensland Government Solar Bonus Scheme for Standard Asset Customers	A program that pays residential and other small energy customers for the surplus electricity generated from roof-top solar photovoltaic (PV) systems that is exported to the Queensland grid.
Regulatory Depreciation	Also referred to as the return of capital—the sum of the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).
Return on Capital	The return necessary to achieve a fair and reasonable rate of return on the assets necessarily invested in the business.
Shoulder Period	Meter type 6 (SAC Non-demand - Residential): The hours between 7am to 4pm and 8pm to 10pm, Monday to Friday and 7am to 10pm weekends.
Site Specific Charge	This charge is calculated specifically for a site and is specific to the individual connection point.

Term	Definition
Small generator	AS4777 compliant generators with an installation size of less than 1MW, connected to the LV network.
Solar Photovoltaic (Solar PV)	A system that uses sunlight to generate electricity for residential use. The system provides power for the premises with any excess production feeding into the electricity grid.
Standard Asset Customer (SAC)	Generally those customers with an annual electricity consumption below 4GW.h per year, whose supply arrangements are consistent across the customer group; and where there is no contribution for their dedicated connection assets.
Standard Control Service	This service class includes network, connection and metering services.
Street lights (Major)	Lamps in common use for Major Road lighting including: a) High Pressure Sodium 100 watt (S100) and above; b) Metal Halide 150 watt (H150) and above; and c) Mercury Vapour 250 watt (M250) and above.
Street lights (Minor)	All lamps in common use for Minor Road lighting, including Mercury Vapour, High Pressure Sodium and Fluorescent.
Super Economy (controlled load 1)	Specified permanently connected appliances are controlled by network equipment so that supply will be permanently available for a minimum period of 8 hours at the absolute discretion of Energex but usually between the hours of 10:00pm and 7:00am. Refer to Appendix 6.
Tariff class	A class of customers for one or more direct control services *who* are subject to a particular tariff or particular tariffs (as per the *Rules* definition).
Time of Use (ToU)	Refers to tariffs that vary according to the time of day at which the electricity is consumed.
Transmission Use of System (TUOS)	Refers to the charges incurred for use of the transmission network.
Unmetered Supply	A customer who takes supply where no meter is installed at the connection point.
Volume (Energy) Charge	This part of the tariff seeks to reflect costs not directly allocated to network drivers and costs that are proportional to the size of the customer. The energy consumption (kW.h) for the period, as recorded by the customer's meter, is utilised to calculate this part of the tariff charge. This charge is applied as a fixed amount (cents) per Kilowatt hour (kW.h).
Volume (Energy) Charge (Off-peak)	This charge is applicable to those customers who are on a Residential and Business, Time of Use tariff. The energy consumption (kW.h) during Off-peak periods (refer to Off-peak Period for Off-peak period times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per Kilowatt hour (kW.h).

Term	Definition
Volume (Energy) Charge (Peak)	This charge is applicable to those customers who are on a Residential and Business, Time of Use tariff. The energy consumption (kW.h) during Peak periods (refer to Peak Period for Peak period times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per Kilowatt hour (kW.h).
Volume (Energy) Charge (Shoulder)	This charge is applicable to those customers who are on a Residential Time of Use tariff. The energy consumption (kW.h) during shoulder periods (refer to Shoulder Period for Shoulder period times), as recorded by the customer's meter, is utilised to calculate this part of the tariff. This charge is applied as a fixed amount (cents) per Kilowatt hour (kW.h).

7 Appendices

No.	Title
1	kV.A adjustment methodology
2	Fee-based services product codes
3	Quoted services product codes
4	Additional Business-2-Business codes
5	Internal procedure for reviewing objections

Appendices

No.	Title
1	kV.A Adjustment Methodology
2	Fee-based services product codes
3	Quoted services product codes
4	Additional Business-2-Business codes
5	Internal procedure for reviewing objections
6	Terms and Conditions for Super Economy & Economy (controlled load) Tariffs

Appendix 1

kV.A Adjustment Methodology

Commencing 1 July 2010, charges for ICC's and CAC's have been adjusted up or down by a relative amount based on the difference between the customers' measured power factor and the power factor neutral point. The adjustment will be applied to the demand and capacity charge elements for 2012-13 as outlined below.

1. kV.A Tariff Adjustment Calculation Methodology

a. $$\text{Actual Power Factor (APF)} = \frac{\text{Maximum monthly kW}}{\text{Maximum monthly kV.A}}$$

where monthly kW and monthly kV.A data is collected from the customer's meter

b. $$\text{Power Factor Adjustment (PFA)} = \text{Multiplier} \times (\text{TPF} - \text{APF}) \times (1 + \text{TPF} - \text{APF})^{\text{index}}$$

where TPF = Target Power Factor (Power factor neutral point of 0.9 for ICCs, 0.85 for CACs)
Multiplier and index are variables set by Energex (as per table below)
The PFA will be limited to the maximum and minimum bounds defined by Energex as required

c. $$\text{Demand Adjustment (kW)} = \text{PFA} \times \text{Maximum monthly demand}$$

$$\text{Capacity Adjustment (kW)} = \text{PFA} \times \text{Nominated monthly demand}$$

The adjustments (measured in kW) will be positive or negative depending on the difference between the customer's actual power factor (APF) and target power factor (TPF). This will result in an increase or decrease to the monthly charge as shown in the formula below.

d. $$\underset{\text{for DUOS(\$)}}{\text{Monthly charge}} = \underbrace{\text{Fixed} + \text{Demand} + \text{Capacity} + \text{Volume Peak} + \text{Volume Off Peak}}_{\textit{Existing parameters}} + \underbrace{\text{Demand Adjustment} + \text{Capacity Adjustment}}_{\textit{kV.A adjustments for 2012-13}}$$

where Demand Adjustment ($) = PFA x Maximum monthly demand (kW) x Demand Charge ($/kW/month)
Capacity Adjustment ($) = PFA x Nominated monthly demand (kW) x Capacity Charge ($/kW/month)

2. kV.A Tariff Adjustment Parameters for 2012-13

Customer Type	Target Power Factor	Index	Multiplier	Maximum Adjustment	Minimum Adjustment
ICC - 110B[1]	0.9000	1.0000	1.0000	0%	0%
ICC - 33B	0.8939	1.5138	1.0900	30%	-30%
ICC - 11B	0.8939	1.5138	1.0900	30%	-30%
CAC - 33L	0.8691	1.4306	1.1500	40%	-40%
CAC - 11B	0.8691	1.4306	1.1500	40%	-40%
CAC - 11L	0.8691	1.4306	1.1500	40%	-40%

1 The power factor adjustment will not be applied to ICC 110 customers due to metering limitations

Appendix 2

Fee-based services – Product Codes

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
Alterations and additions to current metering equipment	Addition and/or alteration to current metering arrangement including exchange and/or move meter.	$101.61	$111.77	AAEM1M	500	Customer requests exchange of their current meter for alternative metering configuration e.g. consolidation of multiple meters for one meter.
				AAEM2M	502	Customer requests exchange of their current meter for alternative metering configuration – Current Transformer (CT) Metering. This product code will always have an Additional Crew product code applied.
				AAMM1M	512	Meter is being relocated and requires Energex to visit site to verify the integrity of the metering equipment.
				AAMM2M	514	Meter is being relocated and requires Energex to visit site to verify the integrity of the metering equipment - Current Transformer (CT) Metering. This product code will always have an Additional Crew product code applied.
Attending loss of supply – low voltage customer installation at fault – business Hours	Energex attends trouble call during business hours and found fault in LV customer's installation.	$113.50	$124.85	LOS	1500	Energex attends loss of supply at the customers request and fault is found to be at the customers installation (switchboard) including tripped safety switch, internal fault, customer overload etc.
Overhead service replacement – single phase	To replace an existing overhead service at customer's request. No material change to load.	$310.73	$341.80	MSOR1P2	920	Customer requests their existing overhead service to be replaced or relocated e.g. as a result of a point of attachment (POA) relocation. No material change to load. Two Phase.
Overhead service replacement – multiple phase	To replace an existing overhead service at customer's request. No material change to load.	$366.04	$402.65	MSOR3P2	924	Customer requests their existing overhead service to be replaced or relocated e.g. as a result of a point of attachment (POA) relocation. No material change to load. Multiple Phases.

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
De–energisation[1]	De-energisation, commenced during business hours.	Nil	Nil	DNSD1MB	300	Retailer requests de-energisation of the customer's premises where the de-energisation can be performed by Pole, Pillar, Post or Fuse.
				DNSD2MB	302	Retailer requests de-energisation of the customer's premises where the de-energisation can be performed by Pole, Pillar, Post or Fuse – Current Transformer (CT) Metering.
				DN$1MB	304	Retailer requests de-energisation of the customer's premises where the customer has ***not paid*** their electricity account and the de-energisation can be performed by Pole, Pillar, Post or Fuse.
				DN$2MB	306	Retailer requests de-energisation of the customer's premises where the customer has ***not paid*** their electricity account and the de-energisation can be performed by Pole, Pillar, Post or Fuse – Current Transformer (CT) Metering.
				DNS	320	Retailer requests de-energisation of the customers' premises - **Main Switch Sealed.**
				DNPN+10	318	Retailer requests de-energisation of the customers premises, and the **planned notification > 10 customers.**
				DNPNU10	322	Retailer requests de-energisation of the customers premises, and the **planned notification < 10** customers.
Meter test[1]	Check that metering installation is accurately measuring energy consumed.	$15.36	$16.90	MIMT1MB	704	A request to conduct a comprehensive review of the customer's metering installation to determine that a customer's energy consumption is being accurately metered by physically testing the meter with a controlled load and calibrating the metering equipment. Business Hours (B/H) Only.

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
				MIMT2MB	706	A request to conduct a comprehensive review of the customer's metering installation to determine that a customer's energy consumption is being accurately metered by physically testing the meter with a controlled load and calibrating the metering equipment. Current Transformer (CT) Metering. Business Hours (B/H) Only.
Meter inspection	Inspection required to check reported or suspected fault and no fault in meter is found.	$90.82	$99.91	MSINSS	957	A request to conduct a site review of the state of the customer's metering installation without physically testing the metering equipment i.e. single premise.
Reconfigure meter	Adjustment to meter setting due to change in tariff and/or time of use settings.	$75.30	$82.83	MRCT1M	1204	A request to make a change from one non-economy (non controlled load) tariff to another non-controlled tariff.
				MRCT2M	1206	A request to make a change from one non-economy (non controlled load) tariff to another non-controlled tariff - Current Transformer (CT) Metering. This product code will always have an Additional Crew product code applied.
				MRCTS1M	1208	A request to make changes to the hours of operation of different meter registers.
				MRCTS2M	1210	A request to make changes to the hours of operation of different meter registers – Current Transformer (CT) Metering. This product code will always have an Additional Crew product code applied.
				MRCL1M	1200	A request to change from one economy (controlled load) tariff to another economy tariff.
				MRCL2M	1202	A request to change from one economy (controlled load) tariff to another economy tariff - Current Transformer (CT) Metering. This product code will always have an Additional Crew product code applied.

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
		Nil	Nil	MRRT1M	1201	A request to make change from Residential Flat to Residential TOU.
				MRRT2M	1203	A request to make change from Residential Flat to Residential TOU - Current Transformer (CT) Metering. This product code will always have an Additional Crew product code applied.
				MRRV1M	1205	A request to revert back from Residential TOU to Residential Flat tariff - (both Current Transformer (CT) Metering and no Current Transformer (CT) Metering.
Off–cycle meter read	Meter read taken off-cycle.	$8.48	$9.33	SRCR	400	Customer requests a check read on the meter due to reported error in the meter reading. This is only used to check the accuracy of the meter reading.
				SRTR	404	Customer requests a transfer read, as a result of transferring to a different Retailer during a billing period.
Site visit	Where crew attends site and either a) service is unable to be performed due to customer's fault (i.e. unfulfilled site visit due to customer missed appointment etc.), or b) crew attends site at customer request where the service is not covered by another fee based service (eg. to provide notification).	$65.22	$71.74	MSWTV	1044	Energex attends a site at the customers request and is unable to perform job due to customers fault - Business Hours (B/H).
		$10.72	$11.79	MSWTV2	1046	Energex (non technical) attends a site at the customers request and is unable to perform job due to customers fault - Business Hours (B/H).
Locating ENERGEX underground cables	Customer requested assistance, from a single crew for a period of up to one hour, in locating ENERGEX underground cables.	n/a	n/a	MSAPLC	938	Customer requests assistance, from a single crew for a period of up to one hour, in locating Energex underground cables. Site visit required.
Temporary connection[1] - Simple	Temporary Connection – Simple. Applies to temporary connections (<12 months) for SACs (incl; temporary builders supplies), typically up to 10 kV.A where minimum technical	$347.64	$382.40	NCT1MB	120	Customer requests a temporary connection and recovery of the temporary builders supply. Small residential and small business (< 25000 kWh).

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
	standards are required. It excludes complex requirements such as those that require greater capacity, longer distance, and/or difficult terrain or temporary large customer connections.			NCT2MB	122	Customer requests a temporary connection and recovery of the temporary builders supply. Small residential and small business (< 25000 kWh) - Current Transformer (CT) Metering.
Re–energisation – business hours	Re-energisation commenced during business hours, visual inspection not required [1.]	$38.55	$42.40	RN$1MB	200	Retailer requests a re-energisation of the customer's premises where the customer has **not paid** their electricity account - Business hours (BH).
				RN$2MB	202	Retailer requests a re-energisation of the customer's premises where the customer has **not paid** their electricity account - Current Transformer (CT) Metering. Business hours (BH).
		Nil	Nil	RNMSS	406	Retailer requests a re-energisation of the customer's premises following a **main switch seal**. Business hours (BH).
	Reading provided for an active site.	$8.48	$9.33	RNNR	238	Retailer requests that fieldwork be undertaken to obtain a new reading rather than using a deemed meter reading. May also be used for Retrospective move-in requests.
		Nil	Nil	RNRR	236	Retailer requests that a meter read be provided, with Energex to determine whether fieldwork is necessary to obtain reading.
Re–energisation (visual) – business hours[1]	Re-energisation commenced during business hours, visual inspection required.	Nil	Nil	RNV1MB	224	Retailer requests a **visual examination** upon re-energisation of the customer's premises. Business hours (BH).
				RNV2MB	226	Retailer requests a **visual examination** upon re-energisation of the customer's premises – Current Transformer (CT) Metering. Business hours (BH).
Re–energisation non–payment (visual) – business hours[1]	Re-energisation, following de-energisation for non payment, commenced during business hours, visual inspection required.	$38.55	$42.40	RN$V1MB	212	Retailer requests a **visual** examination upon re-energisation of the customer's premises where the customer has **not paid** their electricity account. NMI de-energised >30 day. Business hours (BH).

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
				RN$V2MB	214	Retailer requests a **visual** examination upon re-energisation of the customer's premises where the customer has **not paid** their electricity account - Current Transformer (CT) Metering. NMI de-energised >30 day. Business hours (BH).
Re–energisation – after hours	Re-energisation commenced after hours, visual inspection not required.	$92.64[1]	$101.90	RN$1MA	204	Retailer requests a re-energisation of the customer's premises where the customer has **not paid** their electricity account. After hours (AH).
				RN$2MA	206	Retailer requests a re-energisation for the customer's premises where the customer has **not paid** their electricity account - Current Transformer (CT) Metering. After hours (AH).
				RN$1MT	208	Retailer requests a re-energisation for the customer's premises where the customer has **not paid** their electricity account. Retailer has requested a service time of Anytime.
				RN$2MT	210	Retailer requests a re-energisation of the customer's premises where the customer has **not paid** their electricity account - Current Transformer (CT) Metering where the Retailer has requested a service time of Anytime.
		$42.63	$46.89	RNMSSA	408	Retailer requests a re-energisation of the customer's premises following a main **switch seal**. After hours (AH).
				RNMSST	410	Retailer requests a re-energisation of the customer's premises following a **main switch seal**. Anytime.
Re–energisation (visual) – after hours[1]	Re-energisation commenced after hours, visual inspection required.	$92.64	$101.90	RNV1MA	228	Retailer requests a **visual examination** upon re-energisation of customer's premises. After hours (AH).
				RNV2MA	230	Retailer requests a **visual examination** upon re-energisation of the customer's premises - Current Transformer (CT) Metering. After hours (AH).
				RNV1MT	232	Retailer requests a **visual examination** upon re-energisation of the customer's premises where the Retailer has requested a service time of Anytime.

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
				RNV2MT	234	Retailer requests a **visual examination** upon re-energisation of the customer's premises - Current Transformer (CT) Metering where the Retailer has requested a service time of Anytime.
Re–energisation non–payment (visual) – after hours[1]	Re-energisation, following de-energisation for non payment, commenced after hours, visual inspection required.	$92.64	$101.90	RN$V1MA	216	Retailer requests **visual examination** upon re-energisation of a customer's premises where the customer has **not paid** their electricity account. NMI de-energised >30 days and where Retailer has requested service time of After Hours (A/H).
				RN$V2MA	218	Retailer requests a **visual examination** upon re-energisation of the customer's premises where the customer has **not paid** their electricity account - Current Transformer (CT) Metering. NMI de-energised >30 days and where Retailer has requested service time of After Hours (A/H).
				RN$V1MT	220	Retailer requests a **visual** examination upon re-energisation of the customer's premises where the customer has **not paid** their electricity account, and where the Retailer has requested a service time of Anytime. NMI de-energised >30 days.
				RN$V2MT	222	Retailer requests a **visual** examination upon re-energisation of the customer's premises where the customer has **not paid** their electricity account and where the Retailer has requested a service time of Anytime. NMI de-energised >30 days. Current Transformer (CT) Metering.
Supply abolishment - Simple	Retailer requests the service provider to abolish supply at a given connection point. Applies to LV overhead services from an Energex distribution pole to a house, building or property pole; or underground supply arrangements fed from a distribution pillar with fuses not exceeding 100a/ph.	$351.93	$387.12	SA1	800	Retailer requests the Service Provider to abolish supply at a given Connection Point. To be used for Single Dwellings and the Community or Unit one of Multi-Unit Residential complexes.
		$56.33	$61.96	SA3	803	Retailer requests the Service Provider to abolish supply at a given Connection Point. To be used for Multi-Unit Residential complexes, for all units after the Community or Unit One.

Category	Service	Price (GST Exclusive)	Price (GST Inclusive)	Product Code	Peace Charge Code	Service Description
Unmetered supply	Provision of temporary connection and recovery of permanent connection for approved unmetered equipment where an existing LV supply exists.	$155.32	$170.85	DNUMS	328	Customer requests an unmetered supply point to be de-energised.
				TUMS	1400	Customer requests a temporary connection of unmetered equipment to an existing LV supply.
Street light glare screening	The supply and installation of glare shields.	$150.11	$165.12	SLLGAD	602	Customer requests the supply and install of adhesive luminares glare screen(s).
				SLLGSDI	604	Customer requests the supply and install of standard luminares glare screen(s) – Internal.
Replacement of standard luminaries with aero screen units (per street light)	Replacement of existing luminaries with aero screen low glare luminaries.	$347.02	$381.72	SLAU	600	Customer requests the replacement of existing streetlight luminaries with aero screen low glare luminares.

Notes:

1. Services are subject to Schedule 8 of the *Queensland Electricity Regulation 2006*, which either caps the price or sets the price to nil.

Appendix 3

Quoted services – Product Codes

Category	Service	Product Code	Peace Charge Code	Ellipse Product Code	Service Description
Rearrangement of network assets	Where Energex assets are rearranged at customer's request.	MSREL	1026	P051	Where Energex assets are moved at customer's request and estimated expenditure is less than $150k.
		MSOHtoUG	1004		Upgrade from Overhead to Underground Service - Customer requested conversion of existing overhead service to underground service and estimated expenditure is less than $150k.
Customer requested works to allow customer or contractor to work close	Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customer/contractor to work close.	MSTT	1038	P011	Coverage of Low Voltage Mains (eg tiger tails) - Charge where customer requests the line close to a construction site be physically covered to prevent risk of electrocution.
		MSDNNDB	902		Temporary Low Voltage (LV) Service Disconnection - no dismantling – Business Hours (BH).
		MSDNNDA	908		Temporary Low Voltage (LV) Service Disconnection - no dismantling – After Hours (AH).
		MSDNPDB	904		Temporary Low Voltage (LV) Service Disconnection - physical dismantling – Business Hours.
		MSDNPDA	910		Temporary Low Voltage (LV) Service Disconnection - physical dismantling – After Hours (AH).
		MSDNHVB	906		Temporary HV Service Disconnection – Business Hours (BH).
		MSDNHVA	912		Temporary HV Service Disconnection – After Hours (AH).
Non standard data and metering services (type 5-7 metering)	Includes provision of meter data above the minimum requirements and meter inspection to check a reported or suspected fault. Does not include provision of any hardware.	MSOBD	1002	P053	Provision of metering data above Minimum Regulatory Requirements.
		MSLPD	990		Provision of load profile data where available on request by Retailer.

Category	Service	Product Code	Peace Charge Code	Ellipse Product Code	Service Description
		MEMDP	1300		Collection, processing and transfer of higher standard energy data for customers than would otherwise be provided - Retailer requested.
		MSINS	955		A request to conduct a site review of the state of the customer's metering installation(s) without physically testing the metering equipment i.e. multiple premises.
Emergency recoverable works and rectification of illegal connections	Work carried out by Energex as a result of an emergency or third party action.	MSERW	978	P002	Emergency Recoverable Works - Charges for work carried out by Energex as a result of emergency or third party action.
		MSAPIC	930		Rectification of Illegal Connections - Charges for work required as a consequence of illegal connections resulting in damage to the network
Large customer connections	Design & construct of connection assets for large customers.			P060	Design & construct of connection assets for large customers. Generally, large customers have annual consumption > 4 GW.h or Estimated maximum demand > 1 MVA or Estimated generation capacity > 1 MVA.
Design specification/auditing and other subdivision activities	Provision of a detailed estimate/design and/or checking of designs for subdivisions and streetlight services. Also includes other subdivision activities such as pole inspections.	MSDD	958	P006	Provision of Detailed Design Estimate for Low Voltage (LV) Customer Requested Extension/Connection.
		MSSF	1032		Specification Fees - Fee for service when Energex prepares and issues specifications for customer extension works.
					Provision of checking of materials, or a group of similar materials, that are a like for like replacement of current Energex stores materials.
Unmetered services, including street lighting	Provision of services, other than standard connection, for approved unmetered equipment, including street lights.	SLLGUNI	606	P005	Planning, design and installation of unique luminaries glare screening – External.
				P054	Provision of services, other than standard connection for approved unmetered equipment. This includes facilities such as public telephones, traffic signals and public barbecues.

Category	Service	Product Code	Peace Charge Code	Ellipse Product Code	Service Description
After hours provision of any fee based service (excl re-energisation)	The provision of any fee-based service, excluding re-energisation, After Hours.	LOST	1602	P062	Energex attends loss of supply at the customers request, After Hours (AH) and fault is found to be at the customers installation (switchboard) including tripped safety switch, internal fault, customer overload etc.
		MSWTVA	1045		Unfulfilled site visit - After Hours (AH).
		NCT1MA	124		Customer requests a temporary connection and recovery of the temporary builders supply, and where the Retailer has requested a service time of After Hours (AH). Small residential and small business (<25 000 kW.h).
		NCT2MA	126		Customer requests a temporary connection and recovery of the temporary builders supply – Current Transformer (CT) Metering, and where the Retailer has requested a service time of After Hours (AH). Small residential and small business (<25 000 kW.h).
		NCT1MT	128		Customer requests a temporary connection and recovery of the temporary builders supply, and where the Retailer has requested a service time of Anytime. Small residential and small business (<25 000 kW.h).
		NCT2MT	130		Customer requests a temporary connection and recovery of the temporary builders supply – Current Transformer (CT) Metering, and where the Retailer has requested a service time of Anytime. Small residential and small business (<25 000 kW.h).
		AAEM1MAH	501		Adds & Alts - Exchange meter No Current Transformer (CT) Metering - After Hours (AH) / Anytime.
		AAEM2MAH	503		Adds & Alts - Exchange meter Current Transformer (CT) Metering - After Hours (AH) / Anytime.
		AAMM1MAH	513		Adds & Alts - Move meter No Current Transformer (CT) Metering - After Hours (AH) / Anytime.
		AAMM2MAH	515		Adds & Alts - Move meter Current Transformer (CT) Metering - After Hours (AH) / Anytime.
		SA1AH	801		Retailer requests the Service Provider to abolish supply at a given Connection Point. To be used for Single Dwellings; the Community or Unit one of Multi-Unit Residential complexes – After Hours (AH).

Category	Service	Product Code	Peace Charge Code	Ellipse Product Code	Service Description
		SA3AH	804		Retailer requests the Service Provider to abolish supply at a given Connection Point. To be used for Multi-Unit Residential complexes, for all units after the Community or Unit One – After Hours (AH) / Anytime.
Supply abolishment - complex	Retailer requests the service provider to abolish supply at a given connection point. Applies where there are complex arrangements requiring extra resources above that supplied under a simple supply abolishment. Including, underground LV service cables direct jointed to the LV mains cable in the footpath or connected to the LV transformer bushings and terminated on a building wall or other structure inside property; or underground supply arrangements fed from a distribution pillar with fuses exceeding 100a/ph; or HV metered sites.	SA2	802	P056	Retailer requests the service provider to abolish supply at a given connection point. Applies where there are complex arrangements requiring extra resources above that supplied under a simple supply abolishment. Including, underground LV service cables direct jointed to the LV mains cable in the footpath or connected to the LV transformer bushings and terminated on a building wall or other structure inside property; or underground supply arrangements fed from a distribution pillar with fuses exceeding 100a/ph; or HV metered sites.
Additional crew	Where additional crew are required at a service call for health, safety or security reasons.	MSAC	926	P055	Where additional single crew for a period **up to one hour** is required at a service call for health, safety or security reasons during Business Hours (BH).
		MSACA	1700		Where additional single crew for a period of **up to one hour** is required at a service call for health, safety or security reasons After Hours (AH).
		MSACT	1702		Where additional single crew for a period of **up to one hour** is required at a service call for health, safety or security reasons and the Retailer has nominated a service time of AnyTime.
		MSAC2	939		Where additional single crew for a period **greater than one hour but less 2 hours** is required at a service call for health, safety or security reasons during Business Hours (BH).
		MSACA2	1701		Where additional single crew for a period of **greater than one hour** is required at a service call for health, safety or security reasons After Hours (AH).
		MSACT2	1703		Where additional single crew for a period of **greater than one hour** is required at a service call for health, safety or security reasons and the Retailer has nominated a service time of AnyTime.

Category	Service	Product Code	Peace Charge Code	Ellipse Product Code	Service Description
		MSACB	1704		Where additional single crew for a period of **greater than two hours** is required at a service call for health, safety or security reasons during Business Hours (BH).
Temporary connection - complex	Applies to temporary connections, typically above 10 kV.A, where there are complex arrangements requiring extra resources above that supplied under simple temporary supply. Applies to all HV connections and construction supplies. Complex arrangements may be due to long distances, a transformer installation and/or difficult terrain.			P057	Applies to temporary connections, typically above 10 kV.A, where there are complex arrangements requiring extra resources above that supplied under simple temporary supply. Applies to all HV connections and construction supplies. Complex arrangements may be due to long distances, a transformer installation and/or difficult terrain. Also includes temporary supply to construction sites for periods greater than 12 months.
Loss of asset	The residual asset value of non-contributed (Rate 1) & contributed (Rate 2) street lights when removed from service before the end of their useful life at the request of the customer.			P052	Customer requests the removal of non-contributed (Rate 1) and contributed (Rate 2) street lights from service before the end of their useful life.
Other recoverable work (opex)	Customer requested opex services that would not otherwise have been requested for the efficient management of the network, or covered by another service.	MSORW	945	P061	Customer requests OPEX services that would not otherwise have been requested for the efficient management of the network, or covered by another service.
				P044	Customer requests the provision of electricity network data including pole asset information.
				P046	Customer requests application for negotiated connections.
Other recoverable work (capex)	Customer requested services that would not otherwise have been requested for the efficient management of the network, or covered by another service which results in a contributed asset.	MSREAC	1024	P064	Customer requests the provision or receipt of reactive power and energy to and from a connection point.
		MSAPABC	928	P065	Bundling of cables which are carried out at the request of another party.

Appendix 4

Other Business-2-Business services (no charge)

In addition to the Alternative Control Services provided by Energex on a fee for service basis, Energex provides a number of services free of charge (DUOS services). These services are requested through the usual Business-2-Business communication channels. A list of services with full description and product code are provided in the additional product code listing below.

Product Codes	Description	Full Description	Peace Charge Code	Price
New Connections				
NCUP2MB	U/G Perm Supply - CT B/H	New Connection underground with CT during Business Hours	100	$ -
NCUP1MB	U/G Perm Supply - No CT B/H	New Connection underground with no CT during Business Hours	158	$ -
NCUP2MA	U/G Perm Supply - CT A/H	New Connection underground with CT After Hours	106	$ -
NCUP1MA	U/G Perm Supply - No CT A/H	New Connection underground with no CT After Hours	156	$ -
NCUP2MT	U/G Perm Supply - CT Anytime	New Connection underground with CT anytime	118	$ -
NCUP1MT	U/G Perm Supply - No CT Anytime	New Connection underground with no CT anytime	116	$ -
NCOP2MB	O/H Perm Supply - CT B/H	New Connection overhead with CT during Business Hours	104	$ -
NCOP1MB	O/H Perm Supply - No CT B/H	New Connection overhead with no CT during Business Hours	102	$ -
NCOP2MA	O/H Perm Supply - CT A/H	New Connection overhead with CT After Hours	110	$ -
NCOP1MA	O/H Perm Supply - No CT A/H	New Connection overhead with no CT After Hours	108	$ -
NCOP2MT	O/H Perm Supply - CT Anytime	New Connection overhead with CT anytime	114	$ -
NCOP1MT	O/H Perm Supply - No CT Anytime	New Connection overhead with no CT anytime	112	$ -
NCTP2MB	Temp/Perm - CT B/H	New Connection temporary in permanent CT during Business Hours	150	$ -
NCTP1MB	Temp/Perm - No CT B/H	New Connection temporary in permanent no CT during Business Hours	148	$ -
NCTP2MA	Temp/Perm - CT A/H	New Connection temporary in permanent CT After Hours	134	$ -
NCTP1MA	Temp/Perm - No CT A/H	New Connection temporary in permanent no CT After Hours	132	$ -
NCTP2MT	Temp/Perm - CT Anytime	New Connection temporary in permanent CT anytime	138	$ -
NCTP1MT	Temp/Perm - No CT Anytime	New Connection temporary in permanent no CT anytime	136	$ -

Product Codes	Description	Full Description	Peace Charge Code	Price
Unmetered Supply				
NCUMSC	UMS Connection Point Available	New connection unmetered where connection point is available	152	$ -
NCUMSCN	UMS Connection Point Not Available	New connection unmetered where connection point is not available	153	$ -
Special Read				
SRFR	Meter Final Read	Special Read - final read	402	$ -
Additions & Alterations				
AAICL	Install Ctrl Load	Adds & Alts - installed controlled load	516	$ -
AAIHW	Install Hot Water	Adds & Alts - installed hot water	518	$ -
AAIM2MB	Install Meter - CT B/H	Adds & Alts - install meter CT during Business Hours	522	$ -
AAIM1MB	Install Meter - No CT B/H	Adds & Alts - install meter no CT during Business Hours	520	$ -
AAIM2MA	Install Meter - CT A/H	Adds & Alts - install meter CT After Hours	506	$ -
AAIM1MA	Install Meter - No CT A/H	Adds & Alts - install meter no CT After Hours	504	$ -
AAIM2MT	Install Meter - CT Anytime	Adds & Alts - install meter CT anytime	510	$ -
AAIM1MT	Install Meter - No CT Anytime	Adds & Alts - install meter no CT anytime	508	$ -
AARM2M	Remove Meter - CT	Adds & Alts - remove meter CT during Business Hours	526	$ -
AARM1M	Remove Meter - No CT	Adds & Alts - remove meter no CT during Business Hours	524	$ -
Meter Investigation				
MIT2MB	Tamper - CT B/H Only	Meter investigation for tamper CT during Business Hours	710	$ -
MIT1MB	Tamper - No CT B/H Only	Meter investigation for tamper no CT during Business Hours	708	$ -
Customer Initiated Service Upgrades				
MSOU1P2	OH Single Phase - 2 visit	Overhead Service Upgrade	1008	$ -
MSOU2P1	OH 2 Phase - 1 visit	Overhead Service Upgrade	1010	$ -
MSOU2P2	OH 2 Phase - 2 visit	Overhead Service Upgrade	1012	$ -
MSOU3P1	OH 3 Phase - 1 visit	Overhead Service Upgrade	1014	$ -
MSOU3P2	OH 3 Phase - 2 visit	Overhead Service Upgrade	1016	$ -
MSUU2P	U/G Upgrade to 2ph Connection	Underground service upgrade to 2 phase	1040	$ -
MSUU3P	U/G Upgrade to 3ph Connection	Underground service upgrade to 3 phase	1042	$ -
No Charge				
NoCharge	No Charge	No Charge	9999	$ -

Appendix 5

Internal procedure for reviewing objections

5.1 Internal procedure for reviewing objections to tariff class assignment

When Energex (Retail Escalation Manager or Pricing Manager) receives written notification that a customer has an objection to a proposed tariff classification, the procedures described below will be followed.

Where the objection does not involve a site specific price, the review process will be performed by the Retailer Escalation Department. This includes tariff reclassifications for SAC Demand to or from SAC Non-demand.

Where the objection involves a customer moving to or from site specific prices, the review process will be performed by the Pricing Department. This includes tariff reclassifications to or from CAC and ICC.

The internal objection process is as follows:

a) The customer's written objection will be reviewed and Energex will consider any additional information that the customer has provided.

b) Energex will determine the energy usage for the customer based on:

   i. Any information which the customer has provided, or

   ii. Historical consumption data for existing customers; or

   iii. Estimated energy for new customers.

c) Energex will assess the nature of the customer's connection to the network.

d) Energex will determine the correct tariff classification (using data collected and as outlined in Figure 1). There may be exceptions to the application of the first criteria, energy consumption, depending on the nature of a connection.

e) In all cases, the tariff class assignment will be reconsidered and will be escalated to the Retail Escalation Manager and Pricing Manager for review.

f) The customer (or Retailer) will be notified in writing of the tariff classification review within 7 days.

Appendix 6

Terms and Conditions for Super Economy & Economy (controlled load) Tariffs

6.1 Super Economy

Customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI at the discretion of the distribution entity. The tariff is applicable when electricity supply is:

- permanently connected to apparatus; or
- connected to apparatus by means of a socket-outlet as approved by the distribution entity; or
- permanently connected to specified parts of apparatus as approved by the distribution entity.

Supply will be available for a minimum of 8 hours per day; the times when supply is available is subject to variation at the absolute discretion of the distribution entity. Typically, supply will be available between the hours of 10pm to 7am.

Refer to Figure 1 in Tariff Schedule for assignment of customers to tariff classes for further information.

6.2 Economy

Customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI at the discretion of the distribution entity.

This tariff is applicable when electricity supply is:

- connected to apparatus by means of a socket-outlet as approved by the distribution entity; or
- permanently connected to apparatus as approved by the distribution entity except if provision has been made to supply such apparatus under a different tariff in the periods during which supply is not available under this tariff.

Supply will be available for a minimum of 18 hours per day; the times when supply is available is subject to variation at the absolute discretion of the distribution entity.

Refer to Figure 1 in Tariff Schedule for assignment of customers to tariff classes for further information.

Energex

Category Analysis RIN
Basis of Preparation
5. Network Information

May 2014

energex

positive energy

Version control

Version	Date	Description
1.0	20/05/2014	Version provided to KPMG
2.0	30/05/2014	Final version submitted to AER

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.

Group Manager
Regulation and Pricing
Energex
GPO Box 1461
BRISBANE QLD 4001

Table of Contents

1 BoP 5.2-1 – Asset Age Profile – Quantities

The AER requires Energex to provide the quantity currently commissioned by year for the following categories specified in table 5.2.1

- Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)
- Pole top structures, disaggregated by highest operating voltage
- 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 variables:

- Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)
- Pole top structures, disaggregated by highest operating voltage
- 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 ; > 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 information reported is actual information.

1.1 Consistency with CA RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 1.1: 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."	The categories have been reported in line with the values in worksheet 2.2 - Repex
"In instances where Energex considers that both the prescribed asset group categories and the sub-categorisation do not account for an asset on Energex's distribution system, Energex must insert additional rows below the relevant asset group to account for this. Energex must provide the required data, applying a high level descriptor of the asset as the category name. The line item titled "OTHER - PLEASE ADD A ROW IF NECESSARY AND NOMINATE THE CATEGORY' illustrates this requirement. Energex must provide corresponding age profile data in regulatory template 2.2 as per its respective instructions."	Energex has added the category of pole top structures.

Estimated information was provided for the following variables:

- Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)
- Pole top structures, disaggregated by highest operating voltage

- 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) – *Only Specific Values (please refer to outline above)*
- Switchgear By: Highest Operating Voltage ; Switch Function – *Only Specific Values (please refer to outline above)*
- Public Lighting By: Asset Type ; Lighting Obligation – *Only Specific Values (please refer to outline above)*

All other information reported is actual information.

1.2 Sources

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)	NFM FLOSS Sheets (Manually Captured)
Pole top structures, disaggregated by highest operating voltage	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

1.3 Methodology

All data with the exclusion of “Poles - Tower” (which has been manually extracted from FLOSS sheets) has been extracted from NFM. These data extracts were then manipulated in excel to account for various items in the figures.

1.3.1 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 has been categorised by the highest voltage at the site. For example if a site carries 33kV and 11kV conductors, then all poles at the site have been 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 have been excluded.
- Aluminium poles have been 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 has been included in the public lighting asset group.
- All poles with no voltage such as cross street and bollard poles have been allocated to the <=1kV category
- Poles have been allocated based on financial year, i.e. an asset captured in NFM on 5th July 2012 will have a commissioning period of 2012/13.
- The total quantity and year of commissioning is a snapshot of all relevant assets as of 30 June 2013.

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 includes 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 has been 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 has been defined as all other switches found within Energex network, This includes the asset types Airbrake, 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.

1.3.2 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:

    - The pole material
    - The pole foundation
    - The original installation year
    - 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.

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:

- 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)

2) 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 have been pro-rated into the pre spatial NFM period 1970 to 1999.

Poles	*Null Date*	*1900-1920*
< = 1 kV; WOOD	9	2477
> 1 kV & < = 11 kV; WOOD	2	1018[1]
> 11 kV & < = 22 kV; WOOD	0	0
> 22 kV & < = 66 kV; WOOD	0	136
> 66 kV & < = 132 kV; WOOD	0	2
> 132 kV; WOOD	0	0
< = 1 kV; CONCRETE	0	78
> 1 kV & < = 11 kV; CONCRETE	0	78
> 11 kV & < = 22 kV; CONCRETE	0	0
> 22 kV & < = 66 kV; CONCRETE	0	8

Poles	*Null Date*	*1900-1920*
> 66 kV & < = 132 kV; CONCRETE	0	0
> 132 kV; CONCRETE	0	0
> 1 kV & < = 11 kV; STEEL	0	1
> 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.

3) Some poles had material descriptions other than what was specified in the template. These have been treated as follows.

- Poles that have a material type of plastic have been excluded.

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

- Aluminium poles have been combined with steel poles.

Aluminium Poles	*Quantity*
< = 1 kV	319
> 1 kV & < = 11 kV	0

Aluminium Poles	*Quantity*
> 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 have been pro-rated a material based on the ratio of existing known material types; See the following table for numbers of unknown poles as at 30 June 2013.

Asset group		*Pro Rata*		
Pole Max Voltage	Unknown Quantity	Concrete	Steel	Wood
< = 1 kV	1003	1%	45%	54%
> 1 kV & < = 11 kV	275	3%	0%	97%
> 22 kV & < = 66 kV	42	3%	2%	95%
> 66 kV & < = 132 kV	14	*35%*	*11%*	*54%*

4) Staked and nailed poles with an age of older than 1996 is 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.

Asset Category	*Quantity in Error*
< = 1 kV; STAKED	3,979
> 1 kV & < = 11 kV; STAKED	2,707
> 11 kV & < = 22 kV; STAKED	0
> 22 kV & < = 66 kV; STAKED	176

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%

5) Steel LV poles with a date record pre 1970 have been pro-rated 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.

LV Steel Poles	*Quantity*
1900 – 1970	207
Null Date	194

6) All poles with no voltage such as cross street and bollard poles have been allocated to the <=1kV category

7) 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 pro-ration. 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.

8) Due to the static nature of towers within Energex and a low quantity, the age profiles were manually created by Energex maintenance department from source documentation. The figures were manually extracted from FLOSS reports used in the preparation of the Energex annual RIN submissions. The figures for towers were then added into the figures for 132kV Steel Poles.

Pole top structures, disaggregated by highest operating voltage

1) Pole top structures are defined to be cross arms fitted to poles. The following multipliers were applied against the figures calculated for pole assets to determine the quantity of cross arms and their initial ages. Multipliers have been determined from Energex

maintenance department based upon field sampling conducted and knowledge of construction types and their application.

Asset Type	Multiplier
< = 1 kV; STAKED	1.2438
> 1 kV & < = 11 kV; STAKED	1.35
> 11 kV & < = 22 kV; STAKED	0
> 22 kV & < = 66 kV; STAKED	1.35
> 66 kV & < = 132 kV; STAKED	1
> 132 kV; STAKED	1
< = 1 kV; WOOD	1.2438
> 1 kV & < = 11 kV; WOOD	1.35
> 11 kV & < = 22 kV; WOOD	0
> 22 kV & < = 66 kV; WOOD	1.35
> 66 kV & < = 132 kV; WOOD	1
> 132 kV; WOOD	1
< = 1 kV; CONCRETE	1.35
> 1 kV & < = 11 kV; CONCRETE	1.35
> 11 kV & < = 22 kV; CONCRETE	1
> 22 kV & < = 66 kV; CONCRETE	1.35
> 66 kV & < = 132 kV; CONCRETE	0.5

> 132 kV; CONCRETE	0.5
< = 1 kV; STEEL	0
> 1 kV & < = 11 kV; STEEL	0
> 11 kV & < = 22 kV; STEEL	0
> 22 kV & < = 66 kV; STEEL	0
> 66 kV & < = 132 kV; STEEL	0
> 132 kV; STEEL	0

2) It was then assumed that all cross arms prior to 1978/79 has been replaced with a consecutive 35 year life span. For example a 1977/78 start date is updated to 2012/13 to indicate that the asset has been replaced. A 1934 cross arm will inherit a new asset age of 2003/4 to represent two changes with a 35 year life for each cross arm.

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:

- Conductor sizing category (Imperial, Metric or Other)
- The circuit for each conductor
- The minimum pole ages 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 have been sold to customers and Energex believes that there is a benefit to continue to store this data, the data has not be removed from NFM.

4) 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.

Customer Conductor	*Quantity*
Overhead	8.07

5) The following methodology was then used to estimate the age profile:

- 1929-30 was deemed to be the minimum possible age of any conductor by Energex's technical standards.

- All conductors were placed into 3 categories by delineating them based on imperial and metric sizing:
  - 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
  - Metric – This conductor category was used from 1970 till present, these use metric sizing such as MARS 7/.375
  - Other – This conductor category consists of imperial sizing that we currently still use such as 7/12 Steel, therefore these conductors are deemed to be used from 1930 - present.

- All conductors were then logically grouped together based on circuit (continuous conductor spans between two operational points in the network) and conductor category.

- All conductors then inherited the minimum 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:

- Cable sizing category (Imperial, Metric or Other)
- The circuit for each cable
- The minimum connected asset ages 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 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 cables, it has been assumed that where a cable is connected to only customer assets then that cable is also customer owned.

Customer Conductor	*Quantity (km)*
Underground Cable	14.01

4) The following methodology was used to estimate the age profile:

- 1929-30 was deemed to be the minimum possible age of any conductor by Energex's technical standards.
- All cable were placed into 3 categories by delineating them based on imperial and metric sizing:
  - 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
  - Metric – This cable category was used from 1970 till present, these use metric sizing such as 240mm sq.
  - Other – This cable category consists of imperial sizing that we currently still use. There are no underground cable that fall into this category, if cable did exist they would have an acceptable age profile from 1930 - present.
- 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.

5) 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.

Title	*LV*	*11kV*
Base Year	2002	2000
Original Length	5,870km	1,537km
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	1,440km
Allocation Range	1985-2002	1985-2000
Number of years	18yrs	15yrs[1]
Allocation per year	321km	96km

Note 1: Year 1999 was not allocated an additional amount as total shown was within tolerances.

6) 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.

7) Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)A report was run from NFM which counted the number of transformers broken down by:

- Mounting type
- Capacity
- Phasing

Transformers recorded in NFM as being connected to the network have been counted in the total number of assets and year of commissioning information. This method gives (a) the most accurate number currently in use and (b) the date that connectivity information is captured correlates closely with the actual commissioning date.

8) In this extract the year indicated for each asset type is the year the asset was manufactured. If this date is unknown or incorrect (less than 1910 or greater than 2014) then the first event associated with the asset (usually purchase date) has been used. If this date is unknown then the date the slot was installed into NFM is used.

9) This report was imported into excel and transformers with the following unknown values were required to be adjusted for:

   - Transformers with unknown ratings
   - Transformers with unknown dates
   - Transformers with unknown phasing

All values were allocated by pro-rating across known asset quantities in each category.

10) Transformers with an unknown rating were allocated a rating based on existing percentage breakdown of assets. Please see below table for details.

11) Transformers that have an unknown date have been allocated an age based on existing percentage breakdown. Please see the below table for the quantity of transformers without a date that have been pro-rated in the age profile with the assets that had no rating.

Transformer Type	*Percentage Unknown Rating*	*Unknown Rating Quantity*	*Unknown Age Quantity*	*Count of Assets to Age*
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	17.45%	68	1238	1306
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	19.61%	76	924	1000

Transformer Type	*Percentage Unknown Rating*	*Unknown Rating Quantity*	*Unknown Age Quantity*	*Count of Assets to Age*
POLE MOUNTED ; < = 22kV ; > 60 kVA and < = 600 kVA ; MULTIPLE PHASE	62.92%	245	5436	5681
POLE MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	0.00%	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	100.00%	5	1	6
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	79.03%	63	785	848
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	20.97%	17	219	236
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
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
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; < = 60 kVA ; MULTIPLE PHASE	0.08%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 60 kVa and < = 600 kVa ; MULTIPLE PHASE	18.55%	22	32	54
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVa ; MULTIPLE PHASE	81.37%	99	451	550
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; < = 15 MVA	6.98%	3	12	15
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA	1.58%	1	0	1
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 40 MVA	91.44%	35	14	49
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%	0	0	0
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	95.49%	14	1	15
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; > 100 MVA	4.51%	1	0	1
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

12) Transformers with unknown phasing were pro-rated into the known totals for each phasing category and then pro-rated across the years.

13) 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 is needed to balance the rounding error then the next maximum number of assets is modified by a maximum of one and so on and so forth until the value is 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 is recorded in NFM as being connected to the network has been 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 and (b) the date that connectivity information is captured correlates closely with the actual commissioning date.

2) The following definitions were used in the extraction of the data:

   - The switchgear data did not include assets that are in store or held for spares.
   - Operational Switch asset group was defined as all other switches found within Energex network, This includes the asset types Airbrake, Disk Link, Link Pillar, Isolator, Switch Fuse, Dropout, Earth Switch, Fuse Switch, Sectionaliser, Load Transfer Switch, Ring Main Unit, Link Pillar and Disconnect Box.
   - 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 is the year the asset was manufactured, if this date is unknown or incorrect (less than 1910 or greater than 2014) then the first event associated with the asset (usually purchase date) has been used. If this date is unknown then the date the slot was installed into NFM is used. No other date information was available for some assets with dates less than 1910. These assets constituted approximately 0.12% and were allocated to 1911.

4) There is 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 have been allocated based on the mean life of this asset type.

Customer Conductor	*Quantity (km)*
Total to Allocate 1999-2002	76,085
Base Allocation 2002	1,000
Base Allocation 2001	1,000
Base Allocation 2000	1,000
Base Allocation 1999	1,000
Available Allocation	72,085
Mean Age	48
Current Year	2,014
Base Year	2,003
Number of Year No Allocation Required	11
Years to Allocate	37
Allocate Till	1,966
Quantity Allocated Each Year	1,948

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 is needed to balance the rounding error then the next maximum number of assets is modified by a maximum of one and so on and so forth until the value is 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:

- Streetlight age
- Streetlight rate
- Billing type
- Lamp category

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 is updated to 1999 to indicate that the asset has been replaced. A 1934 streetlight will inherit a new asset age of 1994 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	2,722	66,293
Minor Quantity	118,075	35,904
Major Allocation per Year	544.4	16,573.25
Minor Allocation per Year	23,615	8,976

Brackets

1) It has been assumed that a bracket has been 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 have been deemed to be a streetlight pole when the specification is public lighting specific and it contains a rate 1 or 2 streetlight. The age of the poles has been 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 exist on the pole the major streetlight takes precedence.

1.4 Estimates

Estimated information was provided for the following variables:

- 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 ; > 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

1.4.1 Justification for estimates

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 pro-rating methodologies and assumptions used in these adjustments, all data for poles is 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 variables that have been estimated are stated above. These variables were estimated due to a number of transformers lacking data that would allow them to be classified. The unknown data is 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 within the category “< = 11 kV; Operational Switch” 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 estimated to be within the 1910/11 year.

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.

Brackets dated prior to 1910/11 were deemed to be in error, however no other information was available to assign a year. These values were therefore estimated as being in the 1910/11 year.

1.4.2 Basis for estimates

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 is 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 is 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 variables that were estimated incorporate some transformers with unknown data. These transformers were pro-rated 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 within the category "< = 11 kV; Operational Switch" and with a date prior to 1910/11 with a lack of date information were assigned to the 1910/11 year. This is considered to be the best estimate with the lack of available information.

Public Lighting By: Asset Type; Lighting Obligation

Luminaires have been estimated by using a 20 year life span and assuming that each one has been 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 has been replaced on this schedule. For full details please refer to the approach section above.

Bracket lives for 1910/11 have been estimated as those brackets with lives prior to 1910/11 and no other descriptive information to assign a year have been assigned to that year.

2 BoP 5.2-2 – Asset Age Profile – Service Lines – Installed Assets

The AER requires Energex to provide the quantity currently commissioned by year for the following categories specified in table 5.2.1

- **Service Lines By: Connection Voltage; Customer Type; Connection Complexity**

All data is estimated.

2.1 Consistency with CA RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 2.1: 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 below in the methodology and 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 below in the methodology and assumptions.

All data is estimated.

2.2 Sources

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

Table 2.2: Information sources

Variable	Source
Service Lines By: Connection Voltage; Customer Type; Connection Complexity	MARS

2.3 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 which has been used to estimate the age of the assets.

Based on the definitions in the RIN, Energex has only LV service line assets. Where customers require more complex connections and the assets are owned by Energex they are included in the other dedicated asset category (e.g. 11 kV overhead conductor) and are not classified as HV service lines.

2.3.1 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 we do not model/capture their assets
- All LV service lines are a single span making them simple connections.

2.3.2 Approach

1) The breakdown of service line conductor was extracted from MARS though the following logic:

- The total quantity of OH services are based on unique property addresses:
    - all NMIs with the same street number are flattened into one count to accommodate unit blocks;
    - counting instances of NMIs with no street number where we have a lot number only
    - counting instances of NMIs with no street number and no lot number

- Record must have a National Metering Identifier (NMI) associated with the property with one of the following statuses for the NMI
  - Active ('A')
  - De-Energised ('D')
  - Can be metered or unmetered
- Overhead services are identified as:
  - NMI must be a supply type which does not start with a 'U%' identifier (unless the Pole Value indicates overhead) or a "null" identifier
  - Pole value cannot start with SC, SG, SS or 'U%' identifier. (SC, SG and SS denotes substation sites, and U% are underground pillar sites)

2) The expected age range of the different generations of cable where then included to determine the age profile.

CABLE_TYPE	Total	Age range (yrs)
B (Bare Open)	789	Any
N (Concentric Neutral)	13,396	27-38
O (Open wire Neutral)	9,541	38+
P (Parallel web)	145,322	17-38
T (Twisted multiphase)	31,104	17-38
X (XLPE)	219,468	0-17
XMT (XLPE Mitti)	119,787	7-9
Y (4x95 XLPE)	2,719	0-17
UNKNOWN	42,594	Any
Grand Total	**584,720**	

3) The next step was to generate an age profile for each cable type based on:

- the expected age range of assets in-service;
- maximum life of service lines; and
- known replacement and installation volumes over the last 5 years;

The replacement volume was sourced from the overhead service replacement program (CA12) reports.

The installation volume was extracted from MARS. This was based on the creation date of NMIs (National Meter Identifier) that are clearly overhead services.

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.

4) 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.

2.4 Estimates

All data provided for service lines is estimated.

2.4.1 Justification for estimates

Energex has not historically maintained the installation dates of overhead service lines, therefore an estimate is required.

2.4.2 Basis for estimates

The conductor type held within MARS is a reliable source of data that is continually validated and corrected by field inspection. As different conductor types have been installed historically it gives a reasonable estimate of the age profile.

2.5 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 is a low number of cables remaining in service. This is due to the replacement program for a specific type of XLPE cable.

3 BoP 5.2-3 – Asset Age Profile – Mean Economic Life & Standard Deviation

In relation to table 5.2.1, the AER requires Energex to provide mean economic life and standard deviation 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**

Notes:

- **This basis of preparation covers the mean economic life and standard deviation for all asset classes.**
- **Installed assets data will also be provided in a separate basis of preparation.**

3.1 Consistency with CA RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 3.1: 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,	This requirement has been addressed in the preparing template 5.2

Requirements (instructions and definitions)	Consistency with requirements
depreciation and cost of finance.	
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 5.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category. Energex must provide corresponding replacement expenditure data in regulatory template 2.2 as per its instructions	This requirement has been addressed in preparing template 5.2 (specifically for SCADA, network control and protection systems)
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.	
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.	The requirement has been addressed in preparing template 5.2 (specifically for wood poles)
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	This requirement has been addressed in the preparing template 5.2

Requirements (instructions and definitions)	Consistency with requirements
replacement for each asset, multiplied by the number of those assets in service and reported in the asset age profile.	

Estimated information was provided for all asset groups.

3.2 Sources

A number of different systems were used to source the required data, as listed in the table below.

Table 3.2: Information sources

Asset Group	Variable	Source
Poles	ALL Poles - Wood	NFM
	ALL Refurbished poles wood	NFM
	ALL Poles – Steel and Concrete	Engineering Assessment
Pole Top Structures	ALL	Energex CBRM - Cross arms v2.0
Overhead Conductor	< ≈ 1 KV	Engineering Assessment
	> 1 KV & < ≈ 11 KV	Energex CBRM - 11kV conductors v3.0
	> 11 KV & < ≈ 22 KV ; SWER	
	> 22 KV & < ≈ 66 KV	Energex CBRM - 33kV feeders v2.0
	> 66 KV & < ≈ 132 KV	Energex CBRM - 110 132kV feeders v2.0
Underground Cables	< ≈ 1 KV	Energex CBRM - LV conductors v2.0
	> 1 KV & < ≈ 11 KV	Energex CBRM - 11kV cables v3.0
	> 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	Regulatory life
Transformers	POLE MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; SINGLE PHASE	Energex CBRM - Pole Mounted TX v3.0
	POLE MOUNTED ; < ≈ 22KV ; > 60	

Asset Group	Variable	Source
	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 ; < ≈ 22KV ; > 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 ; 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 ; 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 & <	

Asset Group	Variable	Source
	≈ 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	
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	Energex CBRM - sectionalisers v3.0 Energex CBRM - load transfers switches v3.0 Energex RMU CBRM v3.0 Energex CBRM - Air break switches v3.0
	> 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	Energex CBRM - 33kV isolators v2.0 Energex CBRM - Air break switches v3.0
	> 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	Energex CBRM - 132.110kV isolators v2.0
Public Lights	Luminaires	Manufacturer’s specification
	Brackets and Poles	Network Asset Management documentation
	Lamps	Public lighting maintenance contract and customer billing data
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS	ALL	Engineering Assessments and Regulatory lives

3.3 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.

For the majority of asset classes, economic life data was extracted CBRM models. For assets 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 is approximated by the square root of the mean.

3.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Standard deviation of economic life is approximated by the square root of the mean in accordance with the RIN Guideline
- The economic life of < = 22kV wood poles is assumed to be the same as11kV wood poles
- The economic life of low voltage steel poles is assumed to be the same as11kV steel poles
- The economic life of SWER conductor is assumed to be the same as11kV conductor
- The economic life of low voltage cables (i.e., <=1kV) is 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 is assumed to be the same as multi-phase pole mounted transformers
- The economic life of ground mounted/indoor chamber mounted transformers >33kV and < 66kV is assumed to be the same as33kV ground mounted/indoor chamber mounted transformers
- The economic life of >11kV and <22kV circuit breakers and switches is assumed to be the same as11kV circuit breakers and switches respectively
- The economic life of >33kV and <66kV circuit breakers and switches is assumed to be the same as33kV circuit breakers and switches respectively
- Steel poles include steel mono poles and steel lattice towers

3.3.2 Approach

Economic life information for the majority of asset classes was extracted from CBRM modelling. Where CBRM modelling had not been undertaken on assets, 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.

Modified expected life

Where CBRM has been used to provide data for economic life, it has been calculated as the “modified expected life” field within each of the CBRM models.

The modified expected life field is calculated based on the following:

- Each asset is assigned an average asset life based on asset type or manufacturer
- Duty and locations 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, aluminium conductor in a corrosive environment (i.e., close to the coast), will have a significantly shorter life than aluminium conductors located in a more benign, dry environment.

Using multiple CBRM models for a single asset category

Where multiple CBRM models were used for a single asset category, the economic life was determined by calculating the average of the economic life of each model.

As an example, 11 kV operation switches combine models for isolators, air brake switches and ring main units. The average modified expected life for each of these components is 42.1, 58.1 and 54.7 respectively. The economic life applied in this case is 48.3, which is the average of those three individual models.

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 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 age of nailed poles at time of replacement excludes poles nailed prior to 1995, as this is 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. This data has been included in the template as Refurbished wood poles in accordance with the RIN.

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 replacement life for service lines was based on Energex's regulatory asset lives for low voltage overhead service line.

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 is based on Energex's Asset Management Division expectations. Note that the population of Base Plate Mounted poles is relatively young compared to the anticipated economic life, hence there is limited failure trend data available).

- Buried in Ground poles, which have an economic life of 30 years (this is 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):

- The volume of lamp replacements for each year between 2008-09 and 2012-13 was collated from the maintenance contract history spreadsheet. These values were then averaged to produce an annual lamp replacement rate for the five year period.
- The total population of lamps was also collated (based on current billed Rate 1 and Rate 2 street lighting sites at the end of each financial year). Similar to the above, these values were averaged to produce a value representing the annual population of lamps over the five year period.
- The lamp economic life was then calculated by dividing the average annual lamp replacement rate over the average annual lamp population for both major and minor road luminaires.

SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS

This asset group includes a number of categories:

- Field devices
- Local network wiring assets
- Communications network assets
- Master station assets
- Pilot cables

Energex also used a number of subcategories to calculate the economic life, as set out in the table below.

Table 3.3: Asset Classes

Asset Group	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 Group	Category
	Multiplex (including MPLS nodes)
MASTER STATION ASSETS	MASTER STATION ASSETS
PILOT CABLES (Other Assets)	Copper pilots (meters of cable installed)
	Fibre Pilots (meters of cable installed)

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 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 Pilot cables, Asset anticipated lives for underground copper cables (60 years), overhead copper cables (30 years) we averaged to give 45 years for copper pilot cables. For overhead / underground fibre cables, 30 years was utilised. Note bracketed figures came from the finance system.

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.

The economic life for each asset category was determined by calculating the volume weighted average of the subcategory asset lives.

3.4 Estimates

All values provided for mean economic life have been estimated in accordance with the definitions contained in the RIN.

All values provided for the standard deviation are estimates as they are a derivate of the mean economic life.

3.4.1 Justification for estimates

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.

3.4.2 Basis for estimates

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

3.5 Explanatory notes

Where Energex does not own assets that meet the category an economic life of zero has been entered.

3.6 Accounting policies

Not applicable.

3.7 Nature of the change

Not applicable.

3.8 Impact of the change

Not applicable.

4 BoP 5.2.4 – Asset Age Profile – SCADA, Network Control and Protection Systems

This BoP covers the quantity of assets currently in commission (by year) 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**
- **Other assets (Pilot Cables)**

These variables are a part of worksheet 5.2 – Asset Age Profile.

Estimated information was provided for the following asset categories:

- **Local Network Wiring Assets**
- **Multiplex age profile**
- **Master Station Assets**

All other information reported is actual information.

4.1 Consistency with CA RIN Requirements

Table 4.1: 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.	This requirement has been addressed in preparing the data for table 5.2.1.
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	This requirement has been addressed in preparing the data for table 5.2.1.

Requirements (instructions and definitions)	Consistency with requirements
in regulatory template 2.2 as per its respective instructions.	
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.	This requirement has been addressed in preparing the data for table 5.2.1.

4.2 Sources

Table 4.2 below sets out the sources from which Energex obtained the required information associated with the BOP.

Table 4.2: 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	CBMD ROSS
Master Station Assets	Internal Excel spreadsheet based on manufacturer's warranty

Variable	Source
	information
Pilot Cables	CBMD

4.3 Methodology

4.3.1 Assumptions

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.

4.3.2 Approach

Energex has broken down each asset category into separate asset subcategories.

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
PILOT CABLES (Other Assets)	Copper pilots (meters of cable installed)
	Fibre Pilots (meters of cable installed)

A number of different methods were used to obtain the required data for each of the asset subcategories, as outlined below.

Field Services

- 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.

- RTUs – a review of SCADA control scheme design documentation was undertake to identify the date when the hardware for each control scheme was changed or installed. By analysing the date when a control scheme was replaced with new hardware, 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 services 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 focussed 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 has been estimated.

- The total volume of multicore cables currently installed in substation assets was extracted from the Multicore Cable Schedule (MCCS) database (at April 2014). This volume was then reduced to account for new cables installation between 1 July 2013 and April 2014, based on an engineering assessment.

- To determine the age profile of multicore cables, Energex analysed the installation date associated with key assets (i.e., circuit breakers) interconnected with the multicore cabling, and used these dates as a basis for apportioning the volume of multicore assets installed for each year.

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 has been 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 – The total population of multiplex assets as at end of 2012-13 was estimated based on an extract from a report prepared on a now decommissioned asset management system (historical installation date information was not recorded for these assets). To estimate the age profile for multiplex assets, Energex analysed the installation dates associated fibre optic cables and used 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 inputted 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 the date of the manufacturer's expiration for each asset. A commissioning date was estimated for each asset by back-casting three years prior to the expiration date. The total volume commissioned Master Station assets was then summed for each financial year.

Other

- Pilot Cables – the CBMD application database was queried to determine commissioning dates for each point to point 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 number of pilot cables installed in each year was determined by summing the number individual pilot cables installed during the year.

4.4 Estimates

4.4.1 Justification for estimates

Energex does not have historical data for local network wiring assets, multiplex assets, and master station assets. As such estimates were required to provide the volume of installed assets by year.

4.4.2 Basis for estimates

The volume of local network wiring assets at 30 June 2013 was estimated based on the current volume of installed assets (at April 2014) less an amount to account for new installations between 1 July 2013 and April 2014. This amount was based on an engineering assessment.

The volume of installed multiplex assets for each year was estimated by apportioning the total amount of multiplex assets in 2012-13 against the asset age profile of fibre optic cables.

The volume of installed master station assets for each year was based on an assumption that each asset was commissioned three years prior to the manufacturer's warranty expiry date.

The detailed methodology for these asset categories can be found in section 1.1.3.1 above.

4.5 Explanatory notes

N/A

5 BoP 5.3-1 – Maximum Demand at Network Level

Worksheet 5.3 requires Energex to provide the following information relating to Maximum Demand at the Network level for each year between the period 2008-09 and 2012-13:

- **Raw Network Coincident MD in MW**
- **Date MD Occurred**
- **Half Hour Time Period MD occurred**
- **Whether maximum demand occurred in winter or summer**
- **Embedded Generation MW**
- **10POE Weather adjusted maximum demand, in MW**
- **50POE Weather adjusted maximum demand, in MW**

5.1 Consistency with CA RIN Requirements

Table 5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In table 5.3.1, Energex must input maximum demand information at the Network level	Information on maximum demand has been 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 1.1.3.2 (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 1.1.3.1 (Assumptions)
Energex must provide inputs for 'Embedded generation' if it has kept and maintained historical data for embedded generation downstream of	Demonstrated in section

Requirements (instructions and definitions)	Consistency with requirements
connection points and if it accounts for such embedded generation in its 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.	1.1.3.2 (Approach)
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 1.1.3.2 (Approach)

Each of the variables required in table 5.3.1 were based on actual demand values. As such, no estimations were required.

5.2 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 5.2 below sets out the sources from which Energex obtained the required information.

Table 5.2: 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

5.3 Methodology

5.3.1 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 the 01/06 – 31/08
- The duration of the summer period is from the 01/12 – end of February
- 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

5.3.2 Approach

Energex applied the following approach to obtain the required information:

- Energex 2013 forecast year covers summer 2012/13 and winter 2013

- 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 of 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 weather correction factors are based on adjusted daily peak demand values at the network level.

- 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 demand incorporating maximum temp, minimum temp, and variables for Fridays, Weekdays and the Christmas shut down period, economic drivers and demographic parameters.

    - 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.

5.4 Estimates

No estimates were made in completing table 5.3.1 (all demand values were based on actual amounts).

5.4.1 Justification for estimates

Not applicable.

5.4.2 Basis for estimates

Not applicable.

5.5 Explanatory notes

Not applicable.

6 BoP 5.4-1 – Maximum Demand and Utilisation – Spatial

Worksheet 5.4 requires Energex to provide information relating to Maximum Demand and Utilisation – Spatial. For each substransmission and zone substation in the network, Energex is required to provide the following information:

- **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**

6.1 Consistency with CA RIN Requirements

Table 6.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 6.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In table 5.4.1, Energex must input maximum demand information for the indicated network segments. Energex must insert rows into the tables for each component of its *network* belonging to that segment. Energex must note instances where it decommissions components of its *network* belonging to that segment in the *basis of preparation*.	Information on maximum demand has been provided in accordance with the template
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 1.1.3.2 (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	Demonstrated in section 1.1.3.1 (Assumptions)

Requirements (instructions and definitions)	Consistency with requirements
demand on a calendar year basis and describe, for example, the months that it includes for any given 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 1.1.3.2 (Approach)
If Energex cannot use raw unadjusted maximum demand as the basis for the information it provides in table 5.4.1, it must describe the methods it employs to populate those tables.	Demonstrated in section 1.1.3.2 (Approach)
Energex must input the normal cyclic rating for each element in each network segment. Energex must provide the seasonal rating that corresponds to the time of the raw adjusted maximum demand. For example, Energex must provide the summer normal cyclic rating of the network segment if the raw adjusted maximum demand occurred in summer. Where Energex does not keep and maintain 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 1.1.3.2 (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. 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). Energex must describe the type of embedded generation data it has provided. For example, Energex may state that it has included scheduled, semi-scheduled and non-scheduled embedded generation in the tables for connection points. In this example, we would be able to calculate native demand by adding these figures to the raw adjusted maximum demand figures. If Energex has not kept and maintained historical data for embedded generation downstream of the specified network segment, it may	Demonstrated in section 1.1.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
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 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 Regulatory Information Notice under Division 4 of Part 3 of the National Electricity Law 32 corrected maximum demand in accordance with best regulatory practice weather correction methodologies.	Demonstrated in section 1.1.3.2 (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. 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). In table 5.4.1, Energex must provide information about the maximum demand at each zone substation in each year, which may not correspond to demand at the time of system peak. If Energex does not record and/or maintain spatial maximum demand coincident to the system maximum demand, Energex must provide spatial maximum demand coincident to a higher network segment. Energex must specify the higher network segment to which the lower network segment is coincident to in the basis of preparation. For example, if Energex does not maintain maximum demand data for zone substations coincident to the system maximum demand, Energex may provide maximum demand data coincident to the connection point. In this example, Energex would specify the relevant connection point in the basis of preparation.	

Each of the variables required under table 5.3.1 were based on actual demand values. As such, no estimations were required.

6.2 Sources

The Substation Investment Forecasting Tool (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 is extracted from SIFT and the Equipment Rating (ERAT) database) and is based on the limiting factor i.e. Transformers, cables or circuit breakers.

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

Table 6.2: 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
Weather Corrected maximum demand 10% POE (MW)	SIFT / SCADA /

Variable	Source
	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

6.3 Methodology

6.3.1 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 from the 01/06 – 31/08
- The duration of the summer period is from the 01/12 – end of February
- 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 on five weather stations, including Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley
- Energex system peak half hour for winter and summer is used to determine the time and date for Coincident demand at the zone and bulk supply substations

6.3.2 Approach

Energex applied the following approach to obtain the required information:

- Energex 2013 forecast year covers summer 2012/13 and winter 2013
- Substation rating data was extracted from the SIFT database and the Equipment Rating (ERAT) database. The rating is the normal cyclic rating which corresponds to the time of the raw adjusted maximum demand.
- 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 is 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.
- 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.
- Non-coincident and coincident MVA values are stored based on the recorded MW and MVAr compensation operating at the half hour of peak demand. The time and date of each peak is recorded in SIFT for each substation and season (i.e., Summer or Winter).
- 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:

- 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. 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.

Decommissioned Sub-transmission Substations

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 Bipass Tunnel	2009

6.4 Estimates

No estimates were made in completing table 5.4.1 (all demand values were based on actual amounts).

6.4.1 Justification for estimates

Not applicable

6.4.2 Basis for estimates

Not applicable.

6.5 Explanatory notes

Not applicable.

Appendix 1 – Peak MVA Differing from Peak MW

Please refer to spreadsheet “5. Network Information – Appendix 1 – Peak MVA Differing from Peak MW”

Energex

Category Analysis RIN
Basis of Preparation
6. Service and Quality

May 2014

energex

positive energy

Version control

Version	Date	Description
1.0	20/05/2014	Version provided to KPMG
2.0	30/05/2014	Final version submitted to AER

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.

Group Manager
Regulation and Pricing
Energex
GPO Box 1461
BRISBANE QLD 4001

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1 BoP 6.3-1 – Sustained Interruptions to Supply

The AER requires Energex to provide the following information relating to Table 6.3.1:

- **Sustained Interruptions to Supply (from 01 July 2008 to 30 June 2013)**

These variables are a part of worksheet 6.3 – Sustained Interruptions.

Actual recorded information was provided for all components of submitted data.

1.1 Consistency with CA RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 1.1: 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 Category Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less).”	Asset category 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 Category Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).	Asset category 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	The category customer base is calculated in accordance with the AER

Requirements (instructions and definitions)	Consistency with requirements
SAIDI and SAIFI.	mandated method.
The MED status of each sustained event must be identified in table 6.3.1	The MED status for each year is included against all events. The AER mandated 2.5 Beta method has been used in the determination MED's for each year.

Actual information was provided for all variables. Whilst the single loss of supply outages are based on actual data, Energex is not able to identify the Feeder/Asset attributable to each outage or the reason for the outage. These fields are populated with a "Unknown" and "Other" values so the single loss data can only be grouped by category.

1.2 Sources

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
Sourced from NFM NO (Network Facilities Management – Network Outage system) and EPM for single loss sustained outages.	NFM/EPM

Sustained outage data was sourced from two systems:

1) NFM – For non-single loss events the Customer Minutes Lost (CML) and Customers Interrupted (CI) by asset category required for the basis of the SAIDI and SAIFI calculations was sourced from Energex's Network Outage recording system NFM NO using an MS Access database.

2) EPM – The single loss outage Customer Minutes Lost (CML) and Customers Interrupted (CI) required for the basis of the SAIDI and SAIFI calculations was sourced from Energex's Corporate reporting system EPM.

3) NFM Customer Base – The category customer base was obtained from NFM in accordance with the AER mandated method of customers at the start and end of the reporting period averaged.

1.3 Methodology

1.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- In classifying each asset failure Energex did interpret the cause table “Reason for interruption” and “Detailed reason for interruption” and cross referenced these criteria to the Energex outage cause codes in use.

- In mapping cause codes used by Energex to the AER cause table there were a number second tier AER “Detailed reason for interruption” causes that had no equivalent to reporting systems used by Energex. These detailed causes were:
  - Animal – Animal nesting/burrowing, etc. and other.
  - Animal – Other
  - Vegetation – Grow-in-Other responsible party

- In recording Single Loss Events Energex does not attribute a cause as used by NFM NO. All single loss events therefore have a null cause code. Energex has made the assumption that these single loss events are “Other” reasons for interruption and have further identified these as “Single Loss of Supply” in the details reason field.

- The asset ID for single loss events is “Unknown” due to EPM corporate reporting being unable to link asset data to the corresponding outage report. This functionality will evolve in future reporting systems as will the ability to attribute a cause to single loss events.

- For column “J” of table 6.3.1 (Average duration of sustained customer interruption) Energex has calculated this duration as the Customer Minutes Lost (CML)amount over the Customers Impacted (CI) figure. This is also consistent with the measure CAIDI which is SAIDI/SAIFI.

- Previous year RIN results submitted by Energex do differ from this CA RIN submission and can wholly be attributable to the different customer base methods applied each year. Energex has continued to evolve its reporting to become fully compliant as is the situation with the Economic Benchmarking and this latest Category RIN.
  - 2011 - For the 2011 RIN Energex used a monthly averaged customer base and for single loss events a manual data extraction and processing activity accounted for a single line entry in RIN Templates.
  - 2012 – For the 2012 RIN Energex used an averaged monthly customer base for all outages including single loss events.
  - 2013 – For the 2013 RIN Energex used a running monthly category customer base to determine SAIDI and SAIFI.

- 2013 EB RIN/CA RIN – AER mandated customer base method of customers on the first and last days of the reporting period was used.

- For MED days before the STPIS scheme introduction (2009, 2010 Financial Years) Energex has calculated the MED threshold using the 2.5 Beta method and applied it to Template 6.3.

- The column J and K of table 6.3.1 states that SAIDI and SAIFI should be entered for unplanned outages only. Energex has assumed that the AER would want to know what SAIDI and SAIFI is attributable to planned interruptions even though entering values in these fields contravenes the column heading.

Effect on unplanned SAIDI (by feeder classification)	Effect on unplanned SAIFI (by feeder classification)

1.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Energex queried the network outage management system and the corporate reporting system EPM to obtain a listing of outages grouped by date, time, asset ID, category and cause as below.

Date of event (DD/MM/YYYY)	Time of interruption (HH:MM)	Asset ID (eg. feeder ID)	Feeder classification (CBD, Urban, Short rural, Long rural)	Reason for interruption (select from options in drop-down box)	Detailed reason for interruption (select from options in column 'O' that correspond with reason in column 'F')
1/07/2008	06:10	TRG3	URBAN	Animal	Animal impact

The “Reason for interruption” and “Detailed reason for interruption” fields were mapped to the Energex cause codes used in the network outage system NFM which facilitated a complete representation of all NFM outages against AER reason and detail reason fields except for the three detailed reasons mentioned in paragraph 1.1.3.1.

2) The outage statistics associated with these asset details were calculated as below:

   a. Number of customers affected – This was a distinct count of customers impacted by each asset outage.

   b. Average duration of interruption – This was the Customer minutes lost/Customers affected.

   c. SAIDI – The Customer Minutes Lost (CML) for each asset interruption was place over the asset category customer base.

      i. SAIDI = CML/Asset category customer

   d. SAIFI – The distinct count of customers for each asset interruption was placed over the asset category customer base.

i. SAIFI = Customers affected/Asset category customer base

Number of customers affected by the interruption	Average duration of sustained customer interruption (minutes)	Effect on unplanned SAIDI (by feeder classification)	Effect on unplanned SAIFI (by feeder classification)	MED
24	70	0.001904	0.00002720	NO

3) 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.

   a. Energex has for all years in the CA RIN performed the 2.5 Beta calculation method to determine the appropriate threshold for daily system SAIDI. This is then referenced in the NFM outage exception table for use in reporting.

MED
NO

1.4 Estimates

N/A

1.4.1 Justification for estimates

N/A

1.4.2 Basis for estimates

N/A

1.5 Explanatory notes

N/A