Energex

Economic Benchmarking RIN

Basis of Preparation

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energex

positive energy

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Version	Date	Description
Final 1.0	28/02/2014	Final version for First Response submission to the AER
Final 2.0	24/04/2014	Final version for Audited submission to the AER

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

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

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2 REVENUE

2.1 Revenue – SCS

The AER requires Energex to provide the following variables relating Standard Control Service (SCS) revenue:

Revenue grouping by chargeable quantity

- DREV0101 – Revenue from Fixed Customer Charges
- DREV0102 – Revenue from Energy Delivery charges where time of use is not a determinant
- DREV0103 – Revenue from On–Peak Energy Delivery charges
- DREV0104 – Revenue from Shoulder period Energy Delivery Charges
- DREV0105 – Revenue from Off–Peak Energy Delivery charges
- DREV0106 – Revenue from controlled load customer charges
- DREV0107 – Revenue from unmetered supplies
- DREV0108 – Revenue from Contracted Maximum Demand charges
- DREV0109 – Revenue from Measured Maximum Demand charges
- DREV0110 – Revenue from metering charges
- DREV0111 – Revenue from connection charges
- DREV0112 – Revenue from public lighting charges
- DREV0113 – Revenue from other Sources
- DREV01 – Total revenue by chargeable quantity

Revenue grouping by Customer type or class

- DREV0201 – Revenue from residential Customers
- DREV0202 – Revenue from non-residential customers not on demand tariffs
- DREV0203 – Revenue from non-residential low voltage demand tariff customers
- DREV0204 – Revenue from non-residential high voltage demand tariff customers
- DREV0205 – Revenue from unmetered supplies
- DREV0206 – Revenue from Other Customers
- DREV02 – Total revenue by customer class

Revenue (penalties) allowed (deducted) through incentive schemes

- DREV0301 – EBSS
- DREV0302 – STPIS
- DREV0303 – Other
- DREV03 – Total revenue of incentive schemes

These variables are a part of worksheet 2 – Revenue and are to be reported for regulatory years 2006 – 2013.

All data stated for total revenue in each table and data stated for 2013 is considered actual information.

All other variables are considered estimated information.

2.1.1 Consistency with EB RIN Requirements

The AER has specified the following requirements in relation to reporting revenue:

Requirements (instructions and definitions)	Consistency with requirements
Energex must report revenues by chargeable quantity (RIN Table 2.1) and by customer class (RIN Table 2.2).	SCS revenue figures have been reported in line with the AERs requirements. Demonstrated in section 2.1.3.
The total of revenues by chargeable quantity must equal the total of revenues by customer class because they are simply two different ways of disaggregating revenue information.	Demonstrated in section 2.1.3
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 2.3).	Not applicable as no revenues reported
3Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 2.3).	All figures for SCS revenue have been reconciled to the regulatory accounts.
Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by Energex to customers… …Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other Sources' (DREV0113).	All SCS revenue was reported in the categories defined by the AER. No SCS revenue was reported against "Revenue from other sources"

Requirements (instructions and definitions)	Consistency with requirements
Energex must allocate revenues to the customer type that most closely reflects the customers from which Energex received its revenue. Revenues that Energex cannot allocate to the customer types DREV0201–DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).	All SCS revenue was reported in the categories defined by the AER.
Energex must report the penalties or rewards of incentive schemes in this table. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the service target performance incentive scheme (STPIS) or efficiency benefit sharing scheme (EBSS) must be reported against the line items for those schemes."	Energex recognises revenues and penalties from incentive schemes however no recoveries have been collected from customers to date.

2.1.2 Sources

RIN Table 2.1 Revenue grouping by chargeable quantity			
Variable Code	Variable	Unit	Source
DREV0101	Revenue from Fixed Customer Charges	$'000	PEACE/Regulatory Accounts
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$'000	PEACE/Regulatory Accounts
DREV0103	Revenue from On–Peak Energy Delivery charges	$'000	PEACE/Regulatory Accounts
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$'000	PEACE/Regulatory Accounts
DREV0105	Revenue from Off–Peak Energy Delivery charges	$'000	PEACE/Regulatory Accounts
DREV0106	Revenue from controlled load customer charges	$'000	PEACE/Regulatory Accounts
DREV0107	Revenue from unmetered supplies	$'000	PEACE/Regulatory Accounts

RIN Table 2.1 Revenue grouping by chargeable quantity			
DREV0108	Revenue from Contracted Maximum Demand charges	$'000	PEACE/Regulatory Accounts
DREV0109	Revenue from Measured Maximum Demand charges	$'000	PEACE/Regulatory Accounts
DREV0110	Revenue from metering charges	$'000	PEACE/Regulatory Accounts
DREV0111	Revenue from connection charges	$'000	PEACE/Regulatory Accounts
DREV0112	Revenue from public lighting charges	$'000	PEACE/Regulatory Accounts
DREV0113	Revenue from other Sources	$'000	PEACE/Regulatory Accounts
DREV01	Total revenue by chargeable quantity	$'000	PEACE/Regulatory Accounts

RIN Table 2.2 Revenue grouping by customer type or class			
Variable Code	Variable	Unit	Source
DREV0201	Revenue from residential Customers	$'000	PEACE/Regulatory Accounts
DREV0202	Revenue from non-residential customers not on demand tariffs	$'000	PEACE/Regulatory Accounts
DREV0203	Revenue from non-residential low voltage demand tariff customers	$'000	PEACE/Regulatory Accounts
DREV0204	Revenue from non-residential high voltage demand tariff customers	$'000	PEACE/Regulatory Accounts
DREV0205	Revenue from unmetered supplies	$'000	PEACE/Regulatory Accounts

RIN Table 2.2 Revenue grouping by customer type or class			
DREV0206	Revenue from Other Customers	$'000	PEACE/Regulatory Accounts
DREV02	Total revenue by customer class	$'000	PEACE/Regulatory Accounts

RIN Table 2.3 Revenue (penalties) allowed (deducted) through incentive schemes			
Variable Code	**Variable**	**Unit**	**Source**
DREV0301	EBSS	$'000	PEACE/Regulatory Accounts
DREV0302	STPIS	$'000	PEACE/Regulatory Accounts
DREV0303	Other	$'000	PEACE/Regulatory Accounts
DREV03	Total revenue of incentive schemes	$'000	PEACE/Regulatory Accounts

2.1.3 Methodology

Historically revenue data was collated by Energex in a Microsoft Access database in categories similar to what is required for the EB RIN. This database is used to report on the under/over-collection of revenue from customers. This database was used along with groupings of revenue classifications to report revenue.

2.1.3.1 Assumptions

The following assumptions were applied:

- All network tariff codes (NTCs) are assumed to be 100% attributable to each applicable variable;
- It has been assumed that all controlled load NTCs can be grouped into “Residential Customers” (DREV0201). This has been assumed because 99.4% of all instances of the controlled load NTCs also are accompanied by the residential NTC; and
- All Feed in Tariff (FIT) payments for Solar NTCs has been excluded from the revenue worksheet and have been included in the Opex worksheet.

2.1.3.2 Approach

1) The revenue database has been built using multiple reports from the Energex billing system (PEACE) where available (2006 – 2008 data existed in a legacy system and disaggregated figures were unavailable). These reports are reconciled to both the Ellipse general ledger and the regulatory accounts. The following reports have been used for regulatory years 2009 – 2013:

- FRC003A
- FRC003B
- FRC111
- FRC123
- FRC247 Detailed
- FRC247 Summary
- MSR296

2) These reports were then collated by the database and revenue transactions were output into excel, classified by tariff "category" and network tariff code.

   The classifications of both tariff "category" and network tariff code are used to drive the classification of revenue into prescribed categories. The tariff category informs "RIN Table 2.1 – Revenue by chargeable quantity"; and the network tariff code informs "RIN Table 2.2 – Revenue by customer type".

3) For RIN Table 2.1 tariff "Categories" were contained in the source data from PEACE and these categories were used to classify most revenue transactions into chargeable quantities. Network tariff codes were used to calculate controlled load customer charges and customer types were used to classify unmetered revenue and public lighting. The mapping of these categories can be seen below:

Variable Code	Variable Description	PEACE Tariff Category
DREV0101	Revenue from Fixed Customer Charges	FIXED
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	VOLUME
DREV0103	Revenue from On–Peak Energy Delivery charges	VOLUME peak
DREV0104	Revenue from Shoulder period Energy Delivery Charges	VOLUME shoulder
DREV0105	Revenue from Off–Peak Energy Delivery charges	VOLUME off peak
DREV0106	Revenue from controlled load customer charges	NTC 9000 - Controlled Load 1 (super economy) NTC 9100 - Controlled Load 2 (economy)

Variable Code	Variable Description	PEACE Tariff Category
DREV0107	Revenue from unmetered supplies	UMS & WML (Customer Type)
DREV0108	Revenue from Contracted Maximum Demand charges	CAPACITY
DREV0109	Revenue from Measured Maximum Demand charges	DEMAND
DREV0110	Revenue from metering charges	-
DREV0111	Revenue from connection charges	-
DREV0112	Revenue from public lighting charges	Streetlights (Customer Type)
DREV0113	Revenue from other Sources	-
DREV01	Total revenue by chargeable quantity	Calculated as sum of variables above

Due to the application of three different database classifications for grouping revenue transactions the risk of double counting needed to be managed. To ensure accuracy, where customer type or NTC was used the values were excluded from the revenue being reported by tariff category. The total values were then cross checked against the regulatory accounts.

4) The customer classification was mapped to the revenue data via the network tariff code. The classification of network tariff codes to the customer types can be seen below:

Variable Code	Variable	Network Tariff Code
DREV0201	Revenue from residential Customers	7600 - Residential - PeakSmart 8400 - Residential Flat 8900 - Residential TOU 9000 - Controlled Load 1 (super economy) 9100 - Controlled Load 2 (economy)
DREV0202	Revenue from non-residential customers not on demand tariffs	8500 - Business Flat 8800 - Business - TOU
DREV0203	Revenue from non-residential low voltage demand tariff customers	8100 - Demand Large 8200 - Demand Medium (121-400)

Variable Code	Variable	Network Tariff Code
		8300 - Demand Small
DREV0204	Revenue from non-residential high voltage demand tariff customers	1000 - (> 40 GWh pa) SSC 2000 - (>4 GWh pa) SSC - 110kV EG 2500 - (>4 GWh pa) SSC - 33kV EG 3000 - (>4 GWh pa) SSC - 11kV EG 3500 - (>4 GWh pa) SSC - 33kV Bus 4000 - (>4 GWh pa) SSC - 11kV Bus 4500 - (>4 GWh pa) SSC - 11kV Line 8000 - HV Demand
DREV0205	Revenue from unmetered supplies	9200 - Streetlights - Rate 1 9300 - Streetlights - Rate 2 9400 - Streetlights - Rate 3 9500 - Watchman Lights 9600 - Unmetered Supply
DREV0206	Revenue from Other Customers	-
DREV02	Total revenue by customer class	Calculated as sum of variables above

5) Once all data was categorised, the figures were compared to the regulatory account totals. The key variances seen in the data were individually addressed:

- To ensure the 2012 and 2013 figures reconciled back to the regulatory accounts, the STPIS Reward was added to the underlying figures sourced from PEACE in accordance with advice from the AER on 1st of April 2014. These adjustments of $30.5 million and $9.6 million respectively have been apportioned over all categories except DREV0113 and DREV0206.
- For 2013, all unmetered supplies (being public lighting, watchman lights and other unmetered supplies) were billed in a similar manner, meaning that disaggregation of the individual charges is not readily available. Energex has therefore apportioned the total unmetered supplies revenue to Revenue from

Unmetered Supplies (DREV0107) and Revenue from Public Lighting (DREV0112) based on the 2011 and 2012 average proportions for these two variables. This does not affect Table 2.2 as both items from Table 2.1 are already aggregated into Revenue from Unmetered Supplies (DREV0205).

- Figures for years 2009 – 2012 showed variances to the regulatory accounts which are due to entries in the general ledger that are not in the PEACE reports, any manual adjustments that were made to the regulatory reports and any missing reports not included in the database. A pro-rata adjustment was made to all figures in these years to match what was stated in the regulatory reports.
- Data from 2006 – 2008 was not available at the level of granularity required as the legacy system data (FACOM) was inaccessible. To estimate this data an average proportion for each figure was obtained from the 2009 – 2013 data. This calculated proportion was then multiplied by the total figure in the regulatory accounts to calculate revenue for the specific variables.

Each required adjustment was recorded and input into the revenue database as a manual adjustment. An excerpt of the spreadsheet used for adjusting the figures to the regulatory accounts is provided below.

				0506		
				30/06/2006		
Group	NTC	Category	Category Code	Act Rev (RIN)	Average	Var
CAC	3500	CAPACITY	DC	$0.3	1%	$0.3
CAC	3500	CAPACITY	DK	($0.0)	0%	($0.0)
CAC	3500	DEMAND	DA	$0.0	0%	$0.0
CAC	3500	DEMAND	DD	$0.5	1%	$0.5
CAC	3500	FIXED	DU	$0.9	2%	$0.9
CAC	3500	FIXED	DUSC	$0.0	0%	$0.0
CAC	3500	VOLUME	DV	$0.0	0%	$0.0
CAC	3500	VOLUME off peak	DO	$0.0	0%	$0.0
CAC	3500	VOLUME peak	DP	$0.1	0%	$0.1
CAC	**3500 Total**			**$1.8**	**4%**	**$1.8**
CAC	4000	CAPACITY	DC	$1.7	3%	$1.7
CAC	4000	CAPACITY	DK	($0.0)	0%	($0.0)
CAC	4000	DEMAND	DA	($0.0)	0%	($0.0)
CAC	4000	DEMAND	DD	$3.2	6%	$3.2
CAC	4000	FIXED	DU	$2.6	5%	$2.6
CAC	4000	FIXED	DUSC	$0.0	0%	$0.0
CAC	4000	VOLUME off peak	DO	$0.0	0%	$0.0
CAC	4000	VOLUME peak	DP	$0.6	1%	$0.6
CAC	**4000 Total**			**$8.0**	**16%**	**$8.0**
CAC	4500	CAPACITY	DC	$11.2	22%	$11.2
CAC	4500	CAPACITY	DK	($0.0)	0%	($0.0)
CAC	4500	DEMAND	DA	($0.1)	0%	($0.1)
CAC	4500	DEMAND	DD	$19.4	39%	$19.4
CAC	4500	FIXED	DU	$6.6	13%	$6.6
CAC	4500	FIXED	DUSC	$0.0	0%	$0.0
CAC	4500	VOLUME off peak	DO	$0.2	0%	$0.2
CAC	4500	VOLUME peak	DP	$2.8	6%	$2.8
CAC	**4500 Total**			**$40.1**	**80%**	**$40.1**
CAC Total				**$49.9**	**100%**	**$49.9**

6) Once the manual adjustments had been input into the revenue database the revenue data was extracted into Excel and was summated through the use of pivot tables into the form required.

7) No figures were reported for RIN Table 2.3 Revenue (penalties) allowed (deducted) through incentive schemes. Energex recognises revenues and penalties from incentive schemes however no recoveries have been collected from customers to date. Energex has been entitled to the full STPIS reward but has elected not to recognise it, as per previous pricing proposals.

2.1.4 Estimates

Data stated for total revenues (variables DREV01 and DREV02) as well as all data for 2013 is actual information. All other figures are estimated.

2.1.4.1 Justification for estimates

Energex does not have historical revenue data broken down into the categories required for RIN Tables 2.1 and 2.2 in Standard Control Services. As such, estimates were required to disaggregate revenue into the required categories. The revenue database contains much more data in recent regulatory years from which to estimate these figures. The figures for regulatory years 2010 - 2013 were therefore considered better estimates than the prior years.

2.1.4.2 Basis for estimates

The figures for RIN Table 2.1 were estimated using the breakdown of revenue into classifications seen in Energex revenue database and originally from PEACE reports. Figures for RIN Table 2.2 were estimated using network tariff codes. Where the total figures obtained from the database did not match that stated in the regulatory accounts, each figure was adjusted to align to reported figures. The detailed methodology for this can be found in section 2.1.3.2 above.

2.1.5 Explanatory notes

Revenue from public lighting can be seen to drop significantly from 2010 to 2011. This is due to the reclassification of public lighting charges relating to the provision, construction and maintenance of public lighting to alternate control services. Conveyance of electricity to public lighting remains a standard control service.

DREV01113 Revenue from other Sources and DREV0206 Revenue from Other Customers include amounts that represent proceeds from a legal settlement.

The increase in Revenue from controlled load customer charges (DREV0106) in 2013 is attributable to a change in the pricing structure to be more cost reflective, applying a time-based allocation approach.

2.1.6 Accounting policies

There were no accounting policy changes that would affect the reported revenue figures. However it should be noted that all revenue figures are based on actual figures reported in the regulatory accounts and not the statutory accounts. This will therefore not include any effects of over/under recovery accounts.

2.1.6.1 Nature of the change

2.1.6.2 Impact of the change

2.2 Revenue – ACS

The AER requires Energex to provide the following variables relating Alternate Control Service (ACS) revenue:

Revenue grouping by chargeable quantity

DREV0101 – Revenue from Fixed Customer Charges

DREV0102 – Revenue from Energy Delivery charges where time of use is not a determinant

DREV0103 – Revenue from On–Peak Energy Delivery charges

DREV0104 – Revenue from Shoulder period Energy Delivery Charges

DREV0105 – Revenue from Off–Peak Energy Delivery charges

DREV0106 – Revenue from controlled load customer charges

DREV0107 – Revenue from unmetered supplies

DREV0108 – Revenue from Contracted Maximum Demand charges

DREV0109 – Revenue from Measured Maximum Demand charges

DREV0110 – Revenue from metering charges

DREV0111 – Revenue from connection charges

DREV0112 – Revenue from public lighting charges

DREV0113 – Revenue from other Sources

DREV01 – Total revenue by chargeable quantity

Revenue grouping by Customer type or class

DREV0201 – Revenue from residential Customers

DREV0202 – Revenue from non-residential customers not on demand tariffs

DREV0203 – Revenue from non-residential low voltage demand tariff customers

DREV0204 – Revenue from non-residential high voltage demand tariff customers

DREV0205 – Revenue from unmetered supplies

DREV0206 – Revenue from Other Customers

DREV02 – Total revenue by customer class

Revenue (penalties) allowed (deducted) through incentive schemes

DREV0301 – EBSS

DREV0302 – STPIS

DREV0303 – Other

DREV03 – Total revenue of incentive schemes

These variables are a part of worksheet 2 – Revenue and are to be reported for regulatory

years 2006-13. All variables are to be reported for alternate control services.

All data stated for ACS revenue is considered actual information

2.2.1 Consistency with EB RIN Requirements

The AER has specified the following requirements in relation to reporting revenue:

Requirements (instructions and definitions)	Consistency with requirements
Energex must report revenues by chargeable quantity (RIN Table 2.1) and by customer class (RIN Table 2.2).	Where figures exist the ACS revenue figures have been reported in line with the AERs requirements
The total of revenues by chargeable quantity must equal the total of revenues by customer class because they are simply two different ways of disaggregating revenue information.	Demonstrated in section 2.2.3
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 2.3).	Not applicable to ACS
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 2.3).	Figures for ACS revenue have been generated from the regulatory accounts for each respective year, supplemented by PEACE data for the 2011 and 2012 years and income statement data for 2012 when no detail was required to be reported for ACS.
Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by Energex to customers… …Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other Sources' (DREV0113).	Where possible, Energex has stated ACS revenues in line with those categories which most closely reflect how customers were charged. All other revenue was stated in "Revenue from Other Sources"
Energex must allocate revenues to the customer type that most closely reflects the customers from which Energex received its revenue. Revenues that Energex cannot allocate to the customer types DREV0201–DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).	Where possible, Energex has stated ACS revenues in line with the AERs customer categories. All other revenue was stated in "Revenue from Other Customers"

Requirements (instructions and definitions)	Consistency with requirements
Alternative Control Services are defined in the NER. By way of context, Alternative Control Services are intended to capture distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Where an AER determination was not in effect at the time Alternative Control Services are for DNSPs located in Queensland, excluded distribution services as determined by the Queensland Competition Authority	Excluded Distribution Services (EDS) have been reported for years 2008 – 2010. ACS has been reported for years 2011 – 2013. Prior to 2008, neither ACS nor Excluded Distribution Services existed in Energex and as such no figures have been reported.

2.2.2 Sources

RIN Table 2.1 Revenue grouping by chargeable quantity			
Variable Code	Variable	Unit	Source
DREV0101	Revenue from Fixed Customer Charges	$'000	Regulatory Accounts/ PEACE reports / income statements
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$'000	Regulatory Accounts
DREV0103	Revenue from On–Peak Energy Delivery charges	$'000	Regulatory Accounts
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$'000	Regulatory Accounts
DREV0105	Revenue from Off–Peak Energy Delivery charges	$'000	Regulatory Accounts
DREV0106	Revenue from controlled load customer charges	$'000	Regulatory Accounts
DREV0107	Revenue from unmetered supplies	$'000	Regulatory Accounts
DREV0108	Revenue from Contracted Maximum Demand charges	$'000	Regulatory Accounts
DREV0109	Revenue from Measured Maximum Demand charges	$'000	Regulatory Accounts
DREV0110	Revenue from metering charges	$'000	Regulatory Accounts / PEACE reports/ income statements
DREV0111	Revenue from connection charges	$'000	Regulatory Accounts

RIN Table 2.1 Revenue grouping by chargeable quantity			
DREV0112	Revenue from public lighting charges	$'000	Regulatory Accounts/ income statement
DREV0113	Revenue from other Sources	$'000	Regulatory Accounts/ income statement
DREV01	Total revenue by chargeable quantity	$'000	Regulatory Accounts

RIN Table 2.2 Revenue grouping by customer type or class

Variable Code	Variable	Unit	Source
DREV0201	Revenue from residential Customers	$'000	Regulatory Accounts
DREV0202	Revenue from non-residential customers not on demand tariffs	$'000	Regulatory Accounts
DREV0203	Revenue from non-residential low voltage demand tariff customers	$'000	Regulatory Accounts
DREV0204	Revenue from non-residential high voltage demand tariff customers	$'000	Regulatory Accounts
DREV0205	Revenue from unmetered supplies	$'000	Regulatory Accounts/ income statement
DREV0206	Revenue from Other Customers	$'000	Regulatory Accounts / PEACE reports/ income statement
DREV02	Total revenue by customer class	$'000	Regulatory Accounts

RIN Table 2.3 Revenue (penalties) allowed (deducted) through incentive schemes

Variable Code	Variable	Unit	Source
DREV0301	EBSS	$'000	Not Applicable
DREV0302	STPIS	$'000	Not Applicable
DREV0303	Other	$'000	Not Applicable
DREV03	Total revenue of incentive schemes	$'000	Not Applicable

2.2.3 Methodology

Figures for ACS revenue have been generated from the regulatory accounts for each respective year, supplemented by PEACE data for the 2011 and 2012 years and income statement data for 2012 when no detail was required to be reported for ACS. Prior to 2008, service classifications for ACS or EDS did not exist for Energex therefore all figures for these years have been reported as zero.

2.2.3.1 Assumptions

All values for ACS for years 2008 – 2010 are based on the regulatory account values for "Excluded Distribution Services".

2.2.3.2 Approach

Prior to 2008, Energex did not have service classifications for ACS or EDS thus no figures have been reported. Between 2008 and 2013 three different approaches were used to report the regulatory accounts:

- years 2008 – 2010 were based on the Queensland Competition Authority (QCA) templates supplemented by PEACE reports in relation to metering charges;
- years 2011 – 2012 were primarily based on the AER templates, supplemented with information from the income statement and PEACE reports to identify revenue associated with Metering, as the AER template only included detail on street lighting, quoted services and fee based services (i.e. with no disaggregation of metering charges); and
- 2013 were based on the AER templates.

The differences have required Energex to follow separate methodologies to report ACS revenues, as detailed below.

ACS Revenue 2008 – 2010

All figures are based on the regulatory accounts submitted to the QCA. The reported ACS revenue variables and their method of calculation from the source documentation are stated in the following table:

Variable Code	Variable Description	Construction Methodology (from 2008 – 2010 regulatory accounts)
DREV0101	Revenue from Fixed Customer Charges	Calculated as the total EDS figure for "Other Income from the Sale of Goods and Services" minus the revenue figures stated for DREV 0110 and DREV0113.
DREV0110	Revenue from metering charges	Calculated as the sum of the EDS "Other Income from the Sale of Goods and Services" figures for Meter Investigation, Meter Read and Meter Reconfiguration, supplemented by detail from

Variable Code	Variable Description	Construction Methodology (from 2008 – 2010 regulatory accounts)
		PEACE reports where required.
DREV0113	Revenue from other Sources	Calculated as the sum of EDS "Other Income from the Sale of Goods and Services" figures for: • Additions and Alterations • Quoted Services • Tiger Tails • Street lighting (glare screening, luminaires) • Infrastructure projects, and • Miscellaneous.
DREV01	Total revenue by chargeable quantity	Calculated as the total EDS "Other Income from the Sale of Goods and Services" figure. (2008 figure has been calculated using "Total Revenue")
DREV0206	Revenue from Other Customers	Calculated as the total EDS "Other Income from the Sale of Goods and Services" figure (or "Total Revenue" for 2008). All revenue was stated as coming from "Other Customers" as a clear customer group was unable to be identified.
DREV02	Total revenue by customer class	Calculated as the total EDS "Other Income from the Sale of Goods and Services" figure (or "Total Revenue" for 2008)

Street lighting was not included in the figures for these regulatory years as it was a part of Standard Control Services (SCS). From 2011, fixed charges for street lighting were reclassified as an ACS, with the variable component remaining as SCS.

ACS Revenue 2011 – 2013

All figures are based on the regulatory accounts submitted to the AER. Data was obtained from the annual RIN submitted however the granular figures for metering revenue for 2011 and 2012 were sourced from the supporting spreadsheets for the income statement and PEACE reports as this data was not required for those years. The reported ACS revenue variables and their method of calculation from the source documentation is provided in the below table.

Variable Code	Variable Description	Construction Methodology (from 2011 – 2013 regulatory accounts)
DREV0101	Revenue from Fixed Customer Charges	Calculated as the sum of revenue figures stated for fee based ACS minus the revenue stated for DREV0110 – Revenue from metering charges plus (in 2012) an allocation of Revenue from capital contributions based on the 2012 Income Statement prorated to balance to the regulatory

Variable Code	Variable Description	Construction Methodology (from 2011 – 2013 regulatory accounts)
		accounts – capital contributions.
DREV0110	Revenue from metering charges	For 2013 the figures were calculated as the sum of revenue figures stated for fee based ACS relating to metering. This includes: • Meter test • Meter inspection • Reconfigure meter • Off-cycle meter read For 2011 and 2012 the figures were obtained from supporting spreadsheets for the income statement. 2012 figures included the following categories: • Meter Reconfiguration • Special Read • Meter Investigation 2011 figures included the following categories: • Meter Configuration • Special Meter Reads • Meter Investigation
DREV0112	Revenue from public lighting charges	For all years, the figures were inclusive of street lighting fixed charges. For 2011 it also included all ACS capital contributions revenue. For 2012 it also included ACS capital contributions revenue supplemented by the income statement to apportion over Fixed Customer Charges, Public Lighting Charges and Other Sources. For 2013 it also included Street Lighting capital contributions.
DREV0113	Revenue from other Sources	Calculated as the total for Quoted Services Revenue. For 2012 it also included ACS capital contributions revenue supplemented by the income statement to apportion over Fixed Customer Charges, Public Lighting Charges and Other Sources. For 2013 it also included Quoted Services capital contributions.
DREV01	Total revenue by chargeable quantity	Calculated as the sum of variables DREV0101, DREV0110, DREV0112 and DREV0113.
DREV0205	Revenue from unmetered supplies	Calculated as the value for street lighting revenue stated in DREV0112.
DREV0206	Revenue from Other Customers	Calculated as the total revenue stated in DREV01 minus that stated for street lighting in DREV0112
DREV02	Total revenue by customer class	Calculated as the total revenue stated in DREV01.

Revenue (penalties) allowed (deducted) through incentive schemes

Incentive schemes do not apply to ACS therefore no revenue or penalties are reported.

2.2.4 Estimates

Not Applicable

2.2.4.1 Justification for estimates

2.2.4.2 Basis for estimates

2.2.5 Explanatory notes

Not Applicable

2.2.6 Accounting policies

There were no accounting policy changes that would affect the reported revenue figures.

2.2.6.1 Nature of the change

2.2.6.2 Impact of the change

3 OPEX

3.1 Opex

The AER requires Energex to provide the following variables relating to opex for Standard Control Services (SCS) and Alternative Control Services (ACS):

3.1 Opex Categories

Current opex categories and cost allocations

DOPEX0101-13 – Individual opex categories

DOPEX01 – Total opex

Historical opex categories and cost allocations

DOPEX0101-13A – Individual opex categories (2011 – 2013)

DOPEX01A – Total opex (2011 – 2013)

DOPEX0101-17B – Individual opex categories (2006 – 2010)

DOPEX01B – Total opex (2006 – 2010)

3.2 Opex consistency

Opex consistency – current CAMs

DOPEX0201 – Opex for network services (required for SCS only)

DOPEX0202 – Opex for metering

DOPEX0203 – Opex for connection services

DOPEX0204 – Opex for public lighting

DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP

DOPEX0206 – Opex for transmission connection point planning

Opex consistency – historical CAMs

DOPEX0201A – Opex for network services (required for SCS only)

DOPEX0202A – Opex for metering

DOPEX0203A – Opex for connection services

DOPEX0204A – Opex for public lighting

DOPEX0205A – Opex for amounts payable for easement levy or similar direct charges on DNSP

DOPEX0206A – Opex for transmission connection point planning

3.3 Provisions (required for SCS only)

DOPEX0301-12 – Provision for dividends

DOPEX0301-12A – Provision for Site Restoration – Toowoomba

DOPEX0301-12B – Provision for Site Restoration - Other

DOPEX0301-12C – Provision for Public Liability Insurance

DOPEX0301-12D – Provision for Employee Benefits

DOPEX0301-12E – Provision for Redundancy

DOPEX0301-12F – Provision for Overhead Service Line Inspections

DOPEX0301-12G – Provision for Environmental Offsets

DOPEX0301-12H – Provision for Home Suite

DOPEX0301-12I – Provision for Other

3.4 Opex for high voltage customers (required for SCS only)

DOPEX0401 – Opex for high voltage customers

These variables are a part of worksheet 3 – Opex and are to be reported for regulatory years 2006 – 2013.

The following data is estimated:

- **DOPEX0101-13 (2006 – 2010)**
- **DOPEX0201-4 (2006 – 2010)**
- **DOPEX0201-2 (2011 – 2013)**
- **DOPEX0201A-2A (2006 – 2013)**
- **DOPEX0301-12A Provision for Site Restoration - Toowoomba**
- **DOPEX0301-12B Provision for Site Restoration - Other**
- **DOPEX0301-12C Provision for Public Liability Insurance**
- **DOPEX0301-12D Provision for Employee Benefits**
- **DOPEX0301-12I Provision for Other**
- **DOPEX0401**

All other data is actual information.

3.1.1 Consistency with EB RIN Requirements

The AER has specified the following requirements in relation to reporting opex:

Requirements (instructions and definitions)	Consistency with requirements
Energex must report Opex in accordance with the categories that they reported in response to their Annual Reporting Requirements.	Energex has reported Opex in accordance with the categories that they reported in response to Annual Reporting Requirements of the relevant years as detailed for RIN Tables 3.1.1 and 3.1.2 below.

Requirements (instructions and definitions)	Consistency with requirements
Energex is required to complete the “Current Opex categories and cost allocations” table if there has been a Material change (over the course of the back cast time series) in Energex’s Cost Allocation Approach, basis of preparation for its Regulatory Accounting Statements or Annual Reporting Requirements.	Energex has reported Opex for all eight years in accordance with the categories that they reported in response to the Final Regulatory Information Notice (Final RIN) for 2012/13, 2013/14 and 2014/15 regulatory reporting issued by the AER to Energex on 28 September 2012. There was a change to the cost allocation method from the 2011 year. Prior to 2011, Energex used Cost Allocation Methods and Procedures (CAMP) as approved by the Queensland Competition Authority (QCA). Since 2011, Energex has been operating under the Cost Allocation Method (CAM) that was approved by the AER. In accordance with advice received from the AER on 1 April 2014, Energex has also recast the information to reflect the current Classification of Services (CoS) for the entire backcast period.
Opex in RIN Table 3.1.1 must be prepared for all Regulatory Years in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements for the most recent completed Regulatory Year. For years where the Cost Allocation Approach and Regulatory Accounting Statements are consistent with those that applied in the most recent completed Regulatory year, total Opex should equal that reported in the Regulatory Accounting Statements.	Opex for financial years from 2006 to 2010 have been backcast using the CAM applicable for financial years from 2011 into opex categories and CoS applicable for the 2013 financial year. For 2011 to 2013 years where the current Cost Allocation Approach has been applied, Opex figures reported in table 3.1.1 reconcile to those in the Regulatory Accounting Statements by line item and in total.
Energex must report its historical Opex categories in RIN Table 3.1.2 in accordance with the Opex activities (eg. vegetation management, emergency response Opex, etc) within the Annual Reporting Requirements that applied in the relevant Regulatory Year. These categories must align with the activities reported in response to the Annual Reporting Requirements for each Regulatory Year. Opex line items reported in table 3.1.2 should equal Opex line items reported in the Regulatory Accounting Statements for each Regulatory Year.	Energex has reported its historical Opex categories in accordance with the Opex within the Annual Reporting Requirements that applied in the relevant Regulatory Year. Opex figures reported in table 3.1.2 equal Opex line items reported in the relevant years’ Regulatory Accounting Statements.

Requirements (instructions and definitions)	Consistency with requirements
For RIN Table 3.2.1 Energex must report Opex for the Opex Variables in accordance with its current reporting arrangements (such as its Cost Allocation Approach). This table must be completed if there has been a Material change (over the course of the back cast time series) in Energex's Cost Allocation Approach, basis of preparation for its Regulatory Accounting Statements or Annual Reporting Requirements.	Energex has reported Opex in the categories as defined in the AER EB RIN. There was a change in cost allocation method from 2011. Opex for 2006 to 2010 are based on backcast data using the current cost allocation method applicable from the 2011 year. Data for 2011 to 2013 are per the current cost allocation and align with those reported in the relevant years' regulatory accounts. In accordance with advice received from the AER on 1 April 2014, Energex has also recast the information to reflect the current Classification of Services (CoS) for the entire backcast period.
For RIN Table 3.2.2 Energex must report Opex in accordance with the AER Variables and the Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years.	Energex has reported Opex in the categories as defined in the AER EB RIN. Total Opex for each year in this table align with that in each year's regulatory accounts.
Energex must report, for all Regulatory Years, financial information on provisions for Standard Control Services in accordance with the requirements of the Cost Allocation Approach and the Regulatory Accounting Statements that were in effect for the relevant Regulatory Year. Provisions must be reported in accordance with the principles and policies within the Annual Reporting Requirements for each Regulatory Year. Financial information on provisions should reconcile to the reported amounts for provisions in the Regulatory Accounting Statements for each Regulatory Year.	Energex has reported, for all Regulatory Years, financial information on provisions for Standard Control Services. Provisions are allocated to services based on Property, Plant & Equipment (PP&E) balances, which is consistent with the Annual RIN. Provisions that are charged to indirect expenditure are apportioned to opex and capex components for the EB RIN based on the overhead allocation ratio for the relevant year, sourced from the supporting working files for the regulatory accounts. Financial information on each provision reconciles to the reported amount for that provision in total in relevant years' regulatory accounts.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the amount of Opex that it would have incurred had it been responsible for operating and maintaining the electricity Distribution Transformers that are owned by its high voltage customers. Where Actual Information is unavailable, this must be estimated based on the Opex Energex incurs for operating similar MVA capacity Distribution Transformers within its own network. Where the MVA capacity of high voltage customer-owned Distribution Transformers is not known, it must be approximated by the observed Maximum Demand for that customer.	Energex is not required to and does not keep a record of electricity Distribution Transformers owned by its high voltage customers. Energex has estimated the MVA capacity of high voltage customer-owned Distribution Transformers by approximating the observed Maximum Demand for that customer. The unit cost per MVA of Distribution Transformers has been estimated based on the portion of opex applied to Distribution Transformers of HV metered customers within Energex's network based on the ratio of the replacement cost of those transformers to the replacement cost of all assets.

3.1.2 Sources

RIN Table 3.1 Opex categories			
Variable Code	**Variable**	**Unit**	**Source**
3.1.1 Current opex categories and cost allocations			
DOPEX0101-13	Individual opex categories	$'000	Peoplesoft & Ellipse Chart of Accounts (COA), Cognos
DOPEX01	Total opex	$'000	Peoplesoft & Ellipse COA, Cognos
3.1.2 Historical opex categories and cost allocations			
DOPEX0101-13A	Individual opex categories (2011 – 2013)	$'000	Annual RIN reporting
DOPEX01A	Total opex (2011 – 2013)	$'000	Annual RIN reporting
DOPEX0101-15B	Individual opex categories (2006 – 2010)	$'000	Annual regulatory accounts and workings
DOPEX01B	Total opex (2006 – 2010)	$'000	Annual regulatory accounts

RIN Table 3.2 Opex consistency			
Variable Code	**Variable**	**Unit**	**Source**
3.2.1 Opex consistency - current CAMs			
DOPEX0201	Opex for network services	$'000	Cognos
DOPEX0202	Opex for metering	$'000	Cognos, COA, Ellipse project ledger
DOPEX0203	Opex for connection services	$'000	N/A
DOPEX0204	Opex for public lighting	$'000	Cognos
DOPEX0205	Opex for amounts payable for easement levy or similar direct charges on DNSP	$'000	N/A
DOPEX0206	Opex for transmission connection point planning	$'000	N/A
3.2.2 Opex consistency - historical CAMs			
DOPEX0201A	Opex for network services	$'000	Annual regulatory accounts, COA
DOPEX0202A	Opex for metering	$'000	Annual regulatory accounts, COA, Ellipse project ledger
DOPEX0203A	Opex for connection services	$'000	N/A
DOPEX0204A	Opex for public lighting	$'000	Annual regulatory accounts
DOPEX0205A	Opex for amounts payable for easement levy or similar direct charges on DNSP	$'000	N/A
DOPEX0206A	Opex for transmission connection point planning	$'000	N/A

RIN Table 3.3 Provisions

Variable Code	Variable	Unit	Source
DOPEX0301-12	Provision for dividends	$'000	Regulatory accounts and workings
DOPEX0301-12A	Provision for Site Restoration - Toowoomba	$'000	Regulatory accounts and workings
DOPEX0301-12B	Provision for Site Restoration - Other	$'000	Regulatory accounts and workings
DOPEX0301-12C	Provision for Public Liability Insurance	$'000	Regulatory accounts and workings
DOPEX0301-12D	Provision for Employee Benefits	$'000	Regulatory accounts and workings
DOPEX0301-12E	Provision for Redundancy	$'000	Regulatory accounts and workings
DOPEX0301-12F	Provision for Overhead Service Line Inspections	$'000	Regulatory accounts and workings
DOPEX0301-12G	Provision for Environmental Offsets	$'000	Regulatory accounts and workings
DOPEX0301-12H	Provision for Home Suite	$'000	Regulatory accounts and workings
DOPEX0301-12I	Provision for Other	$'000	Regulatory accounts and workings

RIN Table 3.4 Opex for high voltage customers			
Variable Code	Variable	Unit	Source
DOPEX0401	Opex for high voltage customers	$'000	MDA reports,

			Pricing model

3.1.3 Methodology

Separate methodologies were applied for each table within the Opex worksheet. The methodologies stated in this basis of preparation relate to both SCS and ACS. Where historical data was required, figures were obtained directly from the regulatory accounts for that period. Backcasting of opex figures was required to complete tables 3.1.1 and 3.2.1 as Energex has been subject to different Classification of Services (CoS) over the period and the cost allocation methodology (CAM) was updated for the 2011 regulatory year. Opex in table 3.4 was estimated separately using data for known Energex high voltage customers.

3.1.3.1 Assumptions

3.1.3.2 Approach

Current opex categories and cost allocations

Table 3.1.1 contains all opex from 2006 – 2013 stated on the basis of the current CoS and CAM. The current CoS and CAM have applied from the 2011 regulatory year. As such the figures stated for years 2011 – 2013 have been taken from the regulatory accounts.

Data for 2006 – 2010 was required to be backcast using the current CoS, CAM and accounting principles.

In 2006 & 2007, Energex was regulated under a revenue cap for all DUOS and non-DUOS services. With the introduction of Full Retail Competition (FRC) in Queensland from 2008, services previously classified as Non-DUOS were reclassified to Excluded Distribution Services (equivalent to the current Alternative Control Services classification). From 2011 these services were sub-classified as Fee Based or Quoted Services.

For Quoted Services, Energex was able to extract the costs and apply the methodology documented below for the change in CAM.

Fee Based Services (FBS) are predominantly retailer-requested, and Energex experienced a significant increase in volumes post-FRC. As data was not available from the financial systems to enable accurate backcasting, Energex has:

1. Extracted available data on the volume of FBS for 2006 & 2007
2. Calculated an average cost for these services post-FRC (based on dollars and volumes)
3. Discounted the average cost by the Consumer Price Index (CPI) for each year
4. Applied the discounted average cost to the volumes for each year to calculate the total FBS cost

Backcasting for the current CAM involved specifying the direct costs in each category then recalculating the oncosts, overhead and other indirect costs based on the rules of the current CAM. The following methodology was used to calculate these figures:

1. Obtained full general ledger COA information for all 5 years. This included data for 2006 & 2007 which was sourced from a previous financial system (Peoplesoft) and required conversion to an equivalent COA format.
2. Developed mapping rules for the 2006-2007 data and the 2008-2010 data to enable identification of the different components required under the current CAM. This included:
    a. Non-regulated costs – to be excluded
    b. Asset disposals – previously forming part of overhead costs but to be excluded
    c. Fleet oncosts – required under the current CAM
    d. Material oncosts – required under the current CAM
    e. Other operating costs – previously forming part of overhead costs but to be excluded and separately reported
    f. Full Retail Competition (FRC) – these project costs were previously reported separately (as it was a pass-through item in the previous regulatory control period) but required to be identified as Business as Usual (BAU) or implementation project costs in the current CAM. BAU costs have been included in general overhead and project costs have been included with DOPEX0113 – Other Operating Costs
    g. Meter reading & network billing – previously service providers, providing services to the Distribution Network Service Provider (DNSP) and other areas, therefore requiring identification of the component for the regulated electricity DNSP only
    h. Call Centre – previously providing services to the Distribution Network Service Provider (DNSP) and other areas, therefore requiring identification of the component for the regulated electricity DNSP only
3. Load the COA information and mapping rules into Cognos to enable the recalculations under the current CAM. This generated fleet and material oncost rates and general overhead rates which could then be applied to the direct costs.
4. Develop reporting rules in Cognos to enable reporting consistent with the current CAM. This included:
    a. Elimination of the previous overhead entries
    b. Allocation of oncost and overhead rates to the relevant direct costs in accordance with the current CAM
    c. Aggregation of COA codes into current RIN reporting line items.

Reconciliations were performed of the total direct costs and total indirect costs to ensure all COA items had been appropriately considered and classified. Validation of the results was also conducted by reviewing the output for reasonableness. For considerations of key movements in the opex figures please refer to the explanatory notes in section 3.1.5 Historical opex categories and cost allocations.

<u>Historical opex categories and cost allocations</u>

Table 3.1.2 requires opex stated on the basis of the CAM used in the applicable regulatory year. Table 3.1.2A contains the categories and figures for years 2011 – 2013 in which the current CAM was applied. Table 3.1.2B contains the categories and figures for years 2006 – 2010 in which the previous CAM was applied. All data for both tables has been sourced directly from the regulatory accounts.

Opex consistency – current cost allocation approach

The opex consistency table based on the current CAM (Table 3.2.1) has been based on the values stated in table 3.1.1 – Current opex categories and cost allocations.

Table 3.1.1 balances to Table 3.2.1 for SCS only. ACS will not balance between the two tables as the only category in Table 3.2.1 relevant to Energex is Opex for Public Lighting (DOPEX0204).

DOPEX0201 – Opex for network services

Network services have been defined in the same manner used in the RAB worksheet as *"a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services"*. Based on this definition the values for "DOPEX0201 – Opex for network services" have been calculated as the total opex value stated in 3.1.1 minus the values for:

- DOPEX0202 – Opex for metering
- DOPEX0203 – Opex for connection services
- DOPEX0204 – Opex for public lighting

DOPEX0202 – Opex for metering

The variable "DOPEX0202 – Opex for metering" could not be calculated directly from figures in RIN Table 3.1.1 for two reasons. Firstly variables for "Meter reading and network billing" included network billing expenditure which was required to be removed. Secondly there was expenditure within other variables that related to operating and maintenance (O&M) costs for metering which needed to be included in the final metering figure. The overall formula used for calculating metering costs was therefore:

$$Opex\ for\ metering = Metering\ Dynamics + Meter\ reading\ and\ network\ billing - network\ billing\ charges + O\&M\ cost\ of\ metering$$

The network billing component for years 2010 – 2013 was extracted directly from detailed spreadsheets supporting the regulatory accounts. Figures for years 2006 – 2009 were the average of the 2010 – 2013 figures as data was not separately identifiable for these years.

The metering O&M costs for years 2009 – 2013 were extracted from selected project ledger information in Ellipse. The figures for 2006 – 2008 were then estimated using the figures from 2009 – 2012. The 2013 year was excluded due to changes in meter testing requirements from that year, thereby rendering the 2013 figures as unrepresentative of the history. The average proportion of O&M costs to total metering costs (net of network billing charges) was calculated for the four years (2009 – 2012) and multiplied by the total metering costs (net of network billing charges) for each year to derive the estimates.

Once all figures were obtained for network billing charges and metering O&M costs, the opex for metering was calculated for each regulatory year using the formula above.

The only component of the formula above that is dependant on oncosts and overheads (and the restatement of figures under the current CAM) are O&M costs of metering, which represent a small proportion of opex for metering. Given the O&M figures are sourced from selected project ledger information and not from entire balances in the general ledger, separate backcasting has not been undertaken for this component.

DOPEX0203 – Opex for connection services

All figures for "DOPEX0203 – Opex for connection services" are zero as Energex classifies all connection expenditure as capex.

DOPEX0204 – Opex for public lighting

Public lighting was reclassified from SCS to ACS from the 2011 regulatory year. Accordingly all figures are sourced from "DOPEX0106 – Other Network Maintenance Costs" and reported as ACS for the entire backcast period.

DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP

All figures for "DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP" were stated as zero as Energex does not pay any easement levies.

DOPEX0206 – Opex for transmission connection point planning

Energex does not have any opex attributable to "DOPEX0206 - Opex for transmission connection point planning" and thus figures are stated as zero.

<u>Opex consistency – historical cost allocation approaches</u>

The opex consistency table based on the historical CAMs (Table 3.2.2) has been based on the values stated in RIN Table 3.1.2 – Historical opex categories and cost allocations.

DOPEX0201A – Opex for network services

Network services have been defined in the same manner used in the RAB worksheet as *"a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services"*. Based on this definition the values for "DOPEX0201A – Opex for network services" have been calculated as the total opex value stated in 3.1.2 minus the values for:

- DOPEX0202A – Opex for metering
- DOPEX0203A – Opex for connection services

- DOPEX0204A – Opex for public lighting

DOPEX0202A – Opex for metering

The variable “DOPEX0202A - Opex for metering” could not be calculated directly from figures in RIN Table 3.1.2 for two reasons. Firstly variables for “Meter reading and network billing” included network billing expenditure which was required to be removed. Secondly there was expenditure within other variables that related to operating and maintenance (O&M) costs for metering which needed to be included in the final metering figure. The overall formula used for calculating metering costs was therefore:

$$Opex\ for\ metering = Metering\ Dynamics + Meter\ reading\ and\ network\ billing - network\ billing\ charges + O\&M\ cost\ of\ metering$$

The network billing component for years 2010 – 2013 was extracted directly from detailed spreadsheets supporting the regulatory accounts. Figures for years 2006 – 2009 were the average of the 2010 – 2013 figures as data was not separately identifiable for these years.

The metering O&M costs for years 2009 – 2013 were extracted from selected project ledger information in Ellipse. The figures for 2006 – 2008 were then estimated using the figures from 2009 – 2012 (2013 was excluded due to changes in meter testing requirements from that year). The average proportion of O&M costs to total metering costs (net of network billing charges) was calculated for the four years (2009 – 2012) and multiplied by the total metering costs (net of network billing charges) for each year to derive the estimates.

Once all figures were obtained for network billing charges and metering O&M costs, the opex for metering was calculated for each regulatory year using the formula above.

DOPEX0203A – Opex for connection services

All figures for “DOPEX0203A – Opex for connection services” are zero as Energex classifies all connection expenditure as capex.

DOPEX0204A – Opex for public lighting

Public lighting (or Streetlighting) was reclassified from SCS to ACS from the 2011 regulatory year. Accordingly:

- figures for 2006 – 2010 are reported as SCS and are sourced from “DOPEX0105B – Streetlighting”

- figures for 2011 – 2013 are reported as ACS and are sourced from “DOPEX0106A – Other Network Maintenance Costs”.

DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP

All figures for “DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP” were stated as zero as Energex does not pay any easement levies.

DOPEX0206 – Opex for transmission connection point planning

Energex does not have any opex attributable to “DOPEX0206 - Opex for transmission connection point planning” and thus figures are stated as zero.

Provisions

Provisions are sourced from the regulatory accounts and/or supporting working files and reconcile to the following categories individually and in total for each regulatory year:

- Provision for Dividends
- Provision for Site Restoration - Toowoomba
- Provision for Site Restoration - Other
- Provision for Public Liability Insurance
- Provision for Employee Benefits
- Provision for Redundancy
- Provision for Overhead Service Line Inspections
- Provision for Environmental Offsets
- Provision for Home Suite
- Provision for Other

The closing balances of provisions for 2010 are not the same as the opening balances of provisions for 2011 for the following reasons:

1) For 2006 to 2010, Provision for Dividends was specifically excluded from regulatory reporting requirements (refer Para 6.11 of *QCA Electricity Distribution: Regulatory Accounting and Information Guidelines Sept 2004*). From 2011 it was reported in the annual regulatory accounts

2) Provision for Defined Benefit Superannuation Fund Deficit was included in provisions in the annual regulatory accounts up to 2010. It has been excluded from 2011 as it is a separate liability in the statutory accounts and is not regarded as a provision.

3) Prior to 2011, services were classified as DUOS and Non-DUOS or as DUOS and Excluded Distribution Services, the combination of which were considered to be DNSP services. Reporting in the EB RIN represents provisions for the DNSP as per the annual regulatory accounts. From 2011, services are classified as SCS, ACS and Non-Regulated. Reporting in the EB RIN represents provisions for SCS only and does not include the portion attributable to ACS per the EB RIN requirements.

Provisions are allocated to services based on Property Plant & Equipment (PP&E) balances, which is consistent with the annual regulatory accounts. Allocation of opening balances is based on the closing PP&E balances of the prior regulatory year. The current year movements and the closing balances are allocated based on the closing PP&E balances of the current regulatory year. Adjustments are made for the difference in allocation percentages between the current and prior regulatory years and reported as "Other adjustment" in the annual regulatory accounts. For the EB RIN reporting, positive adjustments are treated as increases to provisions and negative adjustments are treated as reversals.

Provisions are related to opex, capex or indirect expenditure. When provisions are charged to indirect expenditure, they are allocated to opex and capex through the overhead allocation process. Therefore, provisions that are charged to indirect expenditure are apportioned to opex and capex components for the EB RIN based on the overhead allocation ratio for the relevant year, sourced from the supporting working files for the regulatory accounts. For that reason, those provisions that are charged to indirect expenditure are considered to be estimated information.

The following table provides background on each of the provisions:

Variable Code	Variable	Capex and opex split
DOPEX0301-12	Provision for dividends	Neither opex nor capex. It is related to Net Operating Profit After Tax and charged directly to Retained Earnings. It is reported in the EB RIN under opex for completeness.
DOPEX0301-12A	Provision for Site Restoration - Toowoomba	Charged to indirect expenditure and allocated to opex and capex through overhead allocation.
DOPEX0301-12B	Provision for Site Restoration - Other	Represents "make good" provision and was included in Provision for Other prior to 2011. Charged to indirect expenditure and allocated to opex and capex through overhead allocation.
DOPEX0301-12C	Provision for Public Liability Insurance	Charged to indirect expenditure and allocated to opex and capex through overhead allocation.
DOPEX0301-12D	Provision for Employee Benefits	Up until 2010, Provision for Employee Benefits included Provision for Defined Benefit Superannuation Fund Deficit as per the annual regulatory accounts. Since 2011, Provision for

Variable Code	Variable	Capex and opex split
		Defined Benefit Superannuation Fund Deficit has not been included in Provision for Employee Benefits consistent with the annual regulatory accounts. The increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate for Provision for Long Service Leave and Provision for Annual Leave is not specifically disclosed in the regulatory accounts but contained in the increase/decrease to the provisions. For the EB RIN reporting purposes, they have been calculated and disclosed separately and equivalent amounts have been deducted from increase to provisions. Charged to indirect expenditure and allocated to opex and capex through overhead allocation.
DOPEX0301-12E	Provision for Redundancy	Charged to other support cost directly, therefore 100% allocated to opex.
DOPEX0301-12F	Provision for Overhead Service Line Inspections	Charged to Inspection costs directly, therefore 100% allocated to opex.
DOPEX0301-12G	Provision for Environmental Offsets	Charged to opex and capex directly based on relevant components, not through overhead allocation.
DOPEX0301-12H	Provision for Home Suite	Charged to other support cost directly, therefore 100% allocated to opex. Provision for Home Suite has been included in Provision for Other from 2011 in line with the annual regulatory accounts.
DOPEX0301-12I	Provision for Other	Charged to indirect expenditure and allocated to opex and capex through overhead allocation. The “increase during the period in the

Variable Code	Variable	Capex and opex split
		discounted amount arising from the passage of time and the effect of any change in the discount rate" for Provision for Other represents the escalation for onerous contracts, which represent a portion of this provision.
-	Provision for Regulated Revenue Recoveries	Provision for regulated revenue recoveries is recognised in the statutory accounts as it represents the difference between the recovered and allowed revenue. The other side of the provision entry is the relevant revenue account, so that revenue recognised in the statutory accounts reflects the revenue cap amount, which is consistent with the Energex accounting policy which is based on accounting standards. This provision is not recognised for the Regulated Distribution Business, as the revenue reported each year for SCS reflects the recovered amount. This allows the regulator to determine the under/over recoveries.

Opex for high voltage customers

Energex is required to report the opex it would have incurred if it managed the high voltage (HV) transformers that are managed by customers. This information is not measured and was estimated by multiplying an estimate of the total customer HV transformer capacity by the operating unit cost per MVA of capacity seen in Energex-managed distribution transformers. The following points detail the methodology used.

1) A report was obtained from the Meter Data Agency that contains maximum demand figures for each Energex NMI for the years 2006 – 2013. From this only certain NMIs were determined to be high voltage customers. NMIs with the following network tariff codes (NTCs) were extracted from this report as high voltage:

   - 1000 – (> 40 GWh pa) SSC
   - 2000 – (>4 GWh pa) SSC - 110kV EG
   - 2500 – (>4 GWh pa) SSC - 33kV EG

- 3000 – (>4 GWh pa) SSC - 11kV EG
- 3500 – (>4 GWh pa) SSC - 33kV Bus
- 4000 – (>4 GWh pa) SSC - 11kV Bus
- 4500 – (>4 GWh pa) SSC - 11kV Line
- 8000 – HV Demand

2) The list of NMIs generated from the Meter Data Agency report was also cross-checked against a list of HV Meter customers. Only those NMIs that had a HV NTC and were known to be a HV meter customer were included (as some HV demand customers have low voltage meters).

3) The transformer capacity for each NMI was estimated for each year as a function of the maximum demand. To do this the transformer capacities and average maximum demand figures for 2012 and 2013 were extracted for HV NMIs where Energex manages the distribution transformer. Using these figures an average utilisation rate of the maximum transformer capacity was calculated at 47%. All maximum demand figures extracted in steps 1 and 2 were then divided by 0.47 to obtain an estimated customer transformer capacity.

4) The operating unit cost per MVA of capacity seen in Energex-managed distribution transformers was estimated based on each year's total opex and the relative value of the HV transformers. The unit cost was calculated for each regulatory year using the following formula:

$$\$/MVA = \frac{Total\ operating\ cost \times \frac{Replacement\ cost\ of\ Energex\ HV\ connection\ site\ specific\ customers'\ transformers}{Replacement\ cost\ of\ total\ Energex\ assets}}{Total\ capacity\ of\ Energex\ HV\ connection\ site\ specific\ customers'\ transformers}$$

Total operating cost information was available for each regulatory year however replacement cost information was only available for 2012 and 2013. To obtain the unit cost for years 2006 – 2011 the average ratio of unit cost to total opex was calculated from years 2012 and 2013. This ratio was then multiplied by total opex for years 2006 – 2011 to obtain a unit cost per MVA of capacity for each year.

5) The unit costs per MVA of capacity calculated for each year in step 4 were multiplied by the total estimated customer transformer capacity for each year calculated in step 3. This resulted in estimated opex figures for unmanaged distribution transformers for each regulatory year.

3.1.4 Estimates

Several items within the opex worksheet were required to be estimated.

- All backcast figures reported in RIN Tables 3.1.1 and 3.2.1 (2006 – 2010) are inherently estimated due to the backcasting methodology.

- Figures reported in table 3.1.2 for 2010 are regarded as estimated as this level of detail was not reported in the regulatory accounts for that year.
- Figures stated for metering in RIN Tables 3.1.2 and 3.2.2 have been estimated and, as the figure for network services relies on the metering variable, this too is estimated data.
- Within provisions, some figures were estimated in their split between opex and capex.
- All figures provided in RIN Table 3.4 for high voltage customers are estimated.

All other figures are actual information.

3.1.4.1 Justification for estimates

- Figures were required to be estimated using backcasting due to the change in CoS from 2008 and Energex's revised CAM from 2011.
- Data for metering was required to be estimated as the categories in current and historical CAMs included a network billing component and did not include O&M costs for meters.
- The estimated figures for provisions had not previously been split in the regulatory accounts.
- The opex for High voltage customers where Energex does not own the distribution transformer is not measured by Energex.

3.1.4.2 Basis for estimates

Table	Item	Reason
RIN Table 3.1.1 – Current opex categories and cost allocations	Backcast information for the 2006 – 2010 regulatory years	As this information is recreated based on the current CAM, it cannot be actual. Refer to section 3.1.3.2 Current opex categories and cost allocations above for more detail.
RIN Table 3.2.1 – Opex consistency – current CAMs	Backcast information for the 2006 – 2010 regulatory years	As this information is recreated based on the current CAM, it cannot be actual. Refer to section 3.1.3.2 Opex consistency – current cost allocation approach above for more detail.
RIN Table 3.2.2 – Opex consistency – historical CAMs	Opex for metering (DOPEX0202A) for the 2006 – 2009 regulatory years	Network billing and/or O&M for metering for these years have been estimated. Refer to section 3.1.3.2 Opex consistency – historical cost allocation approaches above for more

Table	Item	Reason
		detail.
RIN Table 3.2.2 – Opex consistency – historical CAMs	Opex for network services (DOPEX0201A) for the 2006 – 2009 regulatory years	Opex for network services (DOPEX0201A) is total opex (DOPEX01B) less opex for metering (DOPEX0202A) less opex for public lighting (DOPEX0204A). As opex for metering (DOPEX0202A) is estimated, then Opex for network services (DOPEX0201A) is also estimated. Refer to section 3.1.3.2 Opex consistency – historical cost allocation approaches above for more detail.
RIN Table 3.3 – Provisions	Selected provisions where the movement is charged to indirect expenditure	Charges to indirect expenditure are allocated to opex and capex through overhead allocation. They are not based on actual expenditure. Refer to section 3.1.3.2 Provisions above for more detail.
RIN Table 3.4 – High voltage customers	All items	Estimated by multiplying an estimate of the total customer HV transformer capacity by the operating unit cost per MVA of capacity seen in Energex-managed distribution transformers.

Please refer to relevant sections under 3.1.3.2 Approach for further details.

3.1.5 Explanatory notes

Current opex categories and cost allocations

The following explanations are provided in relation to Table 3.1.1 Current opex categories and cost allocations:

- SCS Inspection costs (DOPEX0101) are unusually high in 2012, reflecting the initial recognition of an obligation to perform overhead service cable inspections (recognised as a provision in Table 3.3 – refer DOPEX0301F – DOPEX0312F).
- SCS Planned Maintenance costs (DOPEX0102) increased significantly in 2007 due to changed maintenance cycles resulting from the 2004 Electricity Distribution and Service Delivery (EDSD) Review.
- Other Network Maintenance Costs (DOPEX0107) represents the maintenance of streetlights.
- Debt raising costs have been reported in opex from 2011 (DOPEX0112A). Prior to that, the costs were a component of borrowing costs, reported below the

Earnings Before Interest & Tax (EBIT) line. Therefore Debt raising costs (DOPEX0112) are a regulatory adjustment added to opex for all years of the backcast period.

- A significant portion of the increase in SCS Other Operating Costs (DOPEX0113) in 2010 is attributable to the preparation, submission and implementation of the 2010 determination, following transfer from jurisdictional regulation under the Queensland Competition Authority to national regulation under the AER.
- From 2011, SCS Other Operating Costs (DOPEX0113) includes solar photovoltaic (PV) feed in tariff (FiT) payments. For transparency, solar PV FiT payments were $19.4M in 2011, $73.9M in 2012 and $167.1M in 2013.
- ACS Other Operating Costs (DOPEX0113) includes Non-DUOS Services which were classified as SCS for 2006 & 2007 only. From 2008, these services, along with new services provided to retailers under FRC arrangements, were reclassified as Excluded Distribution Services and have been regulated under a price cap. Accordingly, for all years they are reported in Table 3.1.1 as ACS Other Operating Costs, consistent with advice from the AER on 1 April 2014.

The following explanations are provided in relation to Table 3.3 Provisions:

- In most cases, movements in provisions are posted through the overhead pool, meaning that balances reported for opex and capex reflect the apportionment of the overhead pool to opex and capex for each year. Total balances of individual provisions (opex + capex components) reconcile from one year to the next, however the allocation between opex and capex typically vary between years.
- There is no other adjustment line item where these adjustments can be reported.
- Provision for Employee Benefits (DOPEX0301D – DOPEX0312D) shows a significant increase in 2009, primarily due to the recognition of a deficit for the Defined Benefit Superannuation Fund. Previously the Fund was in surplus and recognised as an asset. Energex believes that not all NSPs recognise this liability as a provision.
- Provision for Employee Benefits (DOPEX0301D – DOPEX0312D) shows a modest increase in 2012, mostly due to the lower discount rate used in the calculation of Long Service Leave and Annual Leave. This rate changed from 5.22% in 2011 to 3.04% in 2012.
- Provision for Redundancy (DOPEX0301E – DOPEX0312E) shows a significant increase 2013 due to Energex's deliberate efforts to reduce costs and employee numbers. At the end of the 2013 year, a portion of these costs were likely to be settled in 2014 so were recognised as a provision. The associated opex cost is included in 2013 and will not appear in 2014 when the payments will be made.

- Provision for Overhead Service Line Inspections (DOPEX0301F – DOPEX0312F) was initially recognised in 2012 to inspect faulty overhead service lines, with a corresponding increase in opex inspection costs. The majority of these inspections were completed in 2013, with the remainder completed in 2014.

- Provision for Environmental Offsets (DOPEX0301G – DOPEX0312G) was initially recognised in 2012 for environmental obligations required to offset the unavoidable negative impacts on the natural environment resulting from expected capex. Approximately half of this balance was utilised during the 2013 year when the associated capex was undertaken.

3.1.6 Accounting policies

Energex changed its Cost Allocation Method (CAM) for the 2011 – 2015 regulatory control period to better align with its role as a predominantly distribution business and to align with the National Electricity Rules rules and Cost Allocation Guidelines.

3.1.6.1 Nature of the change

The change in CAM resulted in:

- Separate attribution of material oncosts – material oncosts represent the cost of storing and handling materials which is directly attributable to inventory issues

- Separate attribution of fleet oncosts – fleet oncosts represent 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

- Allocation of the remaining indirect expenditure as general overhead, allocated on the basis of total direct spend

3.1.6.2 Impact of the change

The impact of the change in CAM can be seen between:

- RIN Table 3.1.1 “Current opex categories and costs allocations” and RIN Table 3.1.2 “Historical opex categories and cost allocations”

- RIN Table 3.2.1 “Opex consistency – current CAMs” and RIN Table 3.2.2 “Opex consistency – historical CAMs”

4 ASSETS (RAB)

4.1 Asset Values

The AER requires Energex to provide the following information for Standard Control Services (SCS), Alternate Control Services (ACS) and Network Services (NS):

Regulatory Asset Base Values

- DRAB0101 – Opening value
- DRAB0102 – Inflation addition
- DRAB0103 – Straight line depreciation
- DRAB0104 – Regulatory depreciation
- DRAB0105 – Actual additions (recognised in RAB)
- DRAB0106 – Disposals
- DRAB0107 – Closing value for asset value

Asset value roll forward (the seven variables above broken down to specific asset categories)

- DRAB0201-7 – For overhead network assets less than 33 kV
- DRAB0301-7 – For underground network assets less than 33 kV
- DRAB0401-7 – For distribution substations and transformers
- DRAB0501-7 – For overhead network assets 33 kV and above
- DRAB0601-7 – For underground network assets 33 kV and above
- DRAB0701-7 – Zone substations and transformers
- DRAB0801-7 – For easements
- DRAB0901-7 – For meters
- DRAB1001-7 – For “other” asset items with long lives
- DRAB1101-7 – For “other” asset items with short lives

Total disaggregated RAB asset values

- DRAB1201 – Overhead distribution assets less than 33 kV (wires and poles)
- DRAB1202 – Underground distribution assets less than 33 kV (cables, ducts etc)
- DRAB1203 – Distribution substations including transformers
- DRAB1204 – Overhead assets 33 kV and above (wires and towers / poles etc)
- DRAB1205 – Underground assets 33 kV and above (cables, ducts etc)
- DRAB1206 – Zone substations
- DRAB1207 – Easements
- DRAB1208 – Meters
- DRAB1209 – Other assets with long lives (please specify)
- DRAB1210 – Other assets with short lives (please specify)

DRAB13 – Estimated Value of Capital Contributions or Contributed Assets

These variables are a part of worksheet 4 – Assets (RAB) and have all been calculated using the AER Regulated Asset Base Roll Forward Model.

The following data was estimated:

- **Data for NS**

4.1.1 Consistency with EB RIN Requirements

4.1.1.1 EB RIN Requirements

The AER requires Energex report its Regulated Asset Base (RAB) both in total figures and disaggregated into the asset categories defined in the Economic Benchmarking RIN templates. The definitions of these asset categories can be seen in section 4.1.7 of this report.

To disaggregate the RAB values into the defined asset categories the AER has specified the following:

"Energex must report RAB values in accordance with the standard approach in section 4.1.1 and the Assets (RAB) Financial Reporting Framework in Box 7 below. This is a standard approach that must be used for RAB disaggregation to be followed by all Distribution Network Service Providers (DNSPs) (the Standard Approach).

Where Energex believes it has sufficient information to provide a consistent RAB disaggregation into the RAB Assets in the Assets (RAB) worksheet that better reflects the values of those assets (the Optional Additional Approach), they may also provide this in a separate Excel worksheet."

The standard approach states the following:

"Where RAB Financial Information that can be Directly Allocated to the RAB Assets (as per the definitions in chapter 9) it must be Directly Allocated to those RAB Assets. Financial information can be Directly Allocated to a RAB Asset class where that financial information relates to assets that wholly fall within the definition of that RAB Asset class. For example, financial data associated with poles can be Directly Allocated to Overhead Distribution Assets (Wires And Poles)…

…RAB Financial Information that cannot be Directly Allocated to a single asset category should be allocated in accordance with the RAB allocation approach."

The optional additional approach states the following:

"Where Energex believes they have sufficient information to provide a consistent RAB disaggregation into the categories in the '4. Assets (RAB)' worksheet that better reflects the values of those assets in the addition to the specific standard approach, this must be provided in a separate Excel worksheet, together with details of the calculations undertaken. For clarity, Energex must still provide disaggregated RAB values using the

standard approach if it chooses to also provide optional additional approach values.

The optional additional approach must be prepared in accordance with the Assets (RAB) Financial Reporting Framework. Further, Energex must have the optional additional approach audited."

In either approach the RAB must be broken down into SCS, NS (a subset of SCS), and ACS. The following information from the AER pertains to these categories:

Standard Control Services

"RAB Financial Information must reconcile to:

- *For years prior to any AER determination of RAB values, determinations in relation to RAB values made by the previous jurisdictional regulator unless the Energex has had the RAB 'revalued' in the back cast period. In this case Standard Control Services, RAB Financial Information must reconcile to RAB values of a "rolled back" RAB prepared in accordance with the RAB Framework; or*
- *Any decision that the AER has made in relation to RAB values unless that decision incorporates forecasts (for example, additions for the last year of the previous regulatory period) in which case those forecast values should be replaced with actual values where possible. Actual values must reconcile to amounts reported in the Annual Reporting Requirements; or*
- *For years where the AER has not made a decision on values for the RAB, RAB values must be prepared in accordance with the RAB Framework. In this circumstance, actual additions (recognised in the RAB) and disposals must reconcile to amounts reported in the Annual Financial Statements; or*

This means that, for years prior to when the RAB was revalued, the financial data must reconcile to an estimate of the RAB values that has been calculated by rolling back the RAB from the date of its revaluation in accordance with the RAB Framework. Rolling back the RAB is the opposite of rolling the RAB forward in accordance with the RAB Framework – so additions and inflation are subtracted from the RAB and depreciation is added to the RAB."

Alternate Control Services

"Energex must report the RAB values for its services where the AER has approved a RAB or RAB equivalent for these services. If the AER has not developed a RAB for these services Energex must report '0' in the cells."

The following guidance given by the AER is also noted for the preparation of the RAB data:

"Substation land must be included in the 'substation asset' category. Separate values for substation land may be provided in accompanying documentation to the RIN response."

"Where the RAB includes capital contributions, capital contributions must be reported in the '4. Assets (RAB)' sheet. This data must be provided as a separate entry at DRAB13."

"RAB Assets must be reported inclusive of Dual Function Assets that provide Standard Control Services."

The requirements for RIN Tables 4.1, 4.2 and 4.3 are as follows:

Table 4.1

"Energex must report totals for RAB Financial Information for all years in this table. The total for the RAB Financial Information will reconcile with the RAB Financial Information provided in Table 4.2."

Table 4.2

"Energex must report RAB Asset Financial Information broken down in accordance with the RAB Assets as per the definitions of these categories provided in Chapter 9.

Where DNSPs have previously reported and/or recorded values for Easements, these values must be provided separately in the '4. Assets (RAB)' worksheet. Otherwise, this should be included in the remaining categories. Where relevant, data that includes Easements should be identified."

Table 4.3

"Energex must report average RAB Asset values that have been disaggregated into the categories identified in this table. These must be calculated as the average of the opening and closing RAB values for the relevant Regulatory Year for each of the RAB Assets and should be directly reconcilable to the opening and closing values in Table 4.2 for the relevant categories."

For all tables "if Energex can provide Actual Information for the variables…it must do so; otherwise Energex must provide Estimated Information."

4.1.1.2 Consistency

Energex has produced the RAB figures for the EB RIN based on the RAB Roll Forward Model (RFM) used for the 2010 regulatory determination. SCS figures for 2006 to 2009 (capital expenditure, disposal and resulting RAB values) reconcile to those approved by the AER in the 2010 opening RAB. Consistent with the requirements of the EB RIN, forecast values have been updated with actual information (e.g. capital expenditure, asset disposals) from the regulatory accounts for years 2010 – 2013.

The RAB RFM disaggregates Energex's regulated assets into 29 asset categories. Each of these categories was allocated to one of the 10 specified for the EB RIN, the mapping of which can be found in section 4.1.7. This approach aligns to the standard approach defined by the AER above and as such the optional additional approach has not been used.

Amendments were made to Energex's cost allocation methodology (CAM) for the 2010 determination and are reflected in the subsequent years' regulatory accounts. As per the AER's guidance, all data is to be stated in line with the regulatory accounts, therefore all RAB figures will be based on the CAM applicable for the relevant determination period.

Energex only has ACS assets from 2011 and only ACS street lighting is included in the RFM because of the limited building block for street lighting. Therefore, only ACS street lighting assets are reported. All other asset categories and years for ACS have been marked as zero as per the AER guidance.

Substation land has been included in the substation asset category. For details please refer to Appendix A.

The Energex RAB is inclusive of capital contributions. As such the capital contributions for all years have been included in table 4.3.

Although the original 2005 RAB values included forecast data, for the purposes of the EB RIN the data has been treated as actual information as:

- The AER approved the RAB prior to 2010; and
- 'it is not contingent on judgements and/or assumptions for which there are valid alternatives, which could lead to a materially different presentation'. (This reflected the definition of 'Actual Information' as provided in the AER's Instructions and Definitions.)

4.1.2 Sources

All data prior to 2010 has been sourced from the Roll Forward Model prepared for the AER during the 2010 Regulatory Determination. For subsequent years (2010 onwards) the inputs to the Roll Forward Model have been sourced as follows:

- Actuals for asset capex and disposal – Sourced from the regulatory accounts;
- CPI information – Sourced from the Australian Bureau of Statistics data series A2325846C (eight capital cities periods March to March), in line with the AER approach; and
- WACC for 2011 – 2013 – Sourced from the AER 2010 determination[1]

RIN Table 4.1: Regulatory Asset Base Values

Variable Code	Variable	Source
DRAB0101	Opening value	Regulatory Accounts, ABS, 2010 Determination
DRAB0102	Inflation addition	Regulatory Accounts, ABS, 2010 Determination
DRAB0103	Straight line depreciation	Regulatory Accounts, ABS, 2010 Determination
DRAB0104	Regulatory depreciation	Regulatory Accounts, ABS (for inflation), 2010 Determination, Street lighting depreciation, DRAB0102, DRAB0103
DRAB0105	Actual additions (recognised in RAB)	Regulatory Accounts, ABS, 2010 Determination
DRAB0106	Disposals	Regulatory Accounts, ABS, 2010 Determination

[1] Final Decision – Queensland distribution determination 2010-11 to 2014-15, May 2010

RIN Table 4.1: Regulatory Asset Base Values		
Variable Code	**Variable**	**Source**
DRAB0107	Closing value for asset value	Regulatory Accounts, ABS, 2010 Determination

RIN Table 4.2: Asset value roll forward		
Variable Code	**Variables**	**Source**
DRAB0201-7	Overhead network assets less than 33 kV	Regulatory Accounts, ABS, 2010 Determination
DRAB0301-7	Underground network assets less than 33 kV	Regulatory Accounts, ABS, 2010 Determination
DRAB0401-7	Distribution substations and transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB0501-7	Overhead network assets 33 kV and above	Regulatory Accounts, ABS, 2010 Determination
DRAB0601-7	Underground network assets 33 kV and above	Regulatory Accounts, ABS, 2010 Determination
DRAB0701-7	Zone substations and transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB0801-7	Easements	Regulatory Accounts, ABS, 2010 Determination
DRAB0901-7	Meters	Regulatory Accounts, ABS, 2010 Determination
DRAB1001-7	“Other” asset items with long lives	Regulatory Accounts, ABS, 2010 Determination
DRAB1101-7	“Other” asset items with short lives	Regulatory Accounts, ABS, 2010 Determination

RIN Table 4.3: Total disaggregated RAB asset values		
Variable Code	**Variable**	**Source**
DRAB1201	Overhead distribution assets less than 33 kV (wires and poles)	Regulatory Accounts, ABS, 2010 Determination

RIN Table 4.3: Total disaggregated RAB asset values		
Variable Code	**Variable**	**Source**
DRAB1202	Underground distribution assets less than 33 kV (cables, ducts etc)	Regulatory Accounts, ABS, 2010 Determination
DRAB1203	Distribution substations including transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB1204	Overhead assets 33 kV and above (wires and towers / poles etc)	Regulatory Accounts, ABS, 2010 Determination
DRAB1205	Underground assets 33 kV and above (cables, ducts etc)	Regulatory Accounts, ABS, 2010 Determination
DRAB1206	Zone substations	Regulatory Accounts, ABS, 2010 Determination
DRAB1207	Easements	Regulatory Accounts, ABS, 2010 Determination
DRAB1208	Meters	Regulatory Accounts, ABS, 2010 Determination
DRAB1209	Other assets with long lives (please specify)	Regulatory Accounts, ABS, 2010 Determination
DRAB1210	Other assets with short lives (please specify)	Regulatory Accounts, ABS, 2010 Determination
DRAB13	Estimated Value of Capital Contributions or Contributed Assets	Regulatory Accounts

4.1.3 Methodology

Energex has produced the figures for worksheet 4 based on the RAB Roll Forward Model (RFM) used for the 2011 – 2015 regulatory determination and in-line with the RFM handbook. This RFM was extended from 2010 to 2013 using actual information from the regulatory accounts to produce the information required in the EB RIN. Each RAB asset category found in the RFM was then rolled up into the categories specified in the EB RIN.

Because of this methodology, a particular sub-category (110kV Circuit Breakers) of one of the RFM categories was required to be manually remapped between EB RIN categories to reflect the EB RIN definitions. This reclassification from “Distribution Substations and Transformers” to “Zone Substations and Transformers” is reflected in both the SCS and NS templates as Estimated Information. ACS is not affected as it only contains streetlighting assets.

The RFM for NS was constructed from the RFM for SCS. For ACS the Post Tax Revenue Model (PTRM) developed for the 2010 determination was used to roll forward the RAB using the actual capital expenditure, asset disposals and capital contributions for 2011, 2012 and 2013 years.

4.1.3.1 Assumptions

NS are a subset of SCS and can be estimated by subtracting any capex relating to connection assets.

4.1.3.2 Approach

Standard Control Services

1) The RAB RFM was taken from the last regulatory reset in 2010. This RFM starts with the RAB values for the 2005 regulatory year (excerpt in Figure 4.1 below) and includes the values for:

   - Opening Asset Value;
   - Asset Remaining Life;
   - Asset Standard Life;
   - Forecast Net Capex; and
   - Forecast Regulatory Depreciation.

   Prudent Additional Capex Allowance totals to $37 million and is the difference between the forecast and actual capex for 2005 that was approved by the QCA. It was an upward adjustment to the 2006 opening RAB by the QCA when the actual capex for 2005 was known.

Opening Regulated Asset Base for 2004-05 ($m Nominal)

	Asset Class Name	Opening Asset Value	Remaining Life	Standard Life	Forecast Net Capex	Forecast Regulatory Depreciation	Prudent Additional Capex Allowance
Asset Class 1	OH Sub-transmission lines	137.3	20.2	50.5	39.8	2.6	-25.6
Asset Class 2	UG Sub-transmission cables	232.1	18.0	45.0	54.2	5.9	-31.6
Asset Class 3	OH Distribution Lines	578.4	16.7	45.0	21.3	12.1	5.0
Asset Class 4	UG Distribution Cables	831.2	45.1	60.0	55.4	0.3	21.7
Asset Class 5	Distribution Equipment	49.7	7.9	35.0	15.8	1.4	2.4
Asset Class 6	Substation Bays	325.9	28.4	45.0	30.5	6.2	0.7
Asset Class 7	Substation Establishment	201.4	23.2	57.6	22.6	0.3	0.4

Figure 4.1 – Example original 2005 RAB data

2) Figures for annual capex and asset disposals were then input into the model. The figures for 2005 – 2009 were already populated from the 2010 determination RFM and were not changed. As an additional check these figures were reconciled against the regulatory accounts.

Data for 2010 existed in the original RFM, however these were forecast figures used for the determination. These figures were replaced with actual figures from the regulatory accounts. The regulatory years 2011 – 2013 were also populated with actual figures from the regulatory accounts.

An extract of the inputs into the RFM can be seen in Figures 4.2 and 4.3 below.

Actual Capital Expenditure – As Incurred ($m Nominal)									
Year	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
OH Sub-transmission lines	49.38	45.10	22.70	21.92	44.34	68.93	63.63	43.12	19.29
UG Sub-transmission cables	63.59	60.83	77.06	67.38	91.60	91.82	72.14	56.84	45.53
OH Distribution Lines	50.86	90.10	83.83	100.97	132.09	144.00	130.47	153.81	175.19
UG Distribution Cables	54.88	123.58	144.50	113.87	105.24	161.57	123.26	98.61	146.74
Distribution Equipment	5.39	11.06	12.52	16.57	27.59	29.01	44.20	45.10	53.79
Substation Bays	65.83	59.96	37.59	29.11	39.09	62.03	37.63	44.83	30.44
Substation Establishment	17.43	16.12	12.72	13.85	16.54	18.79	18.08	19.46	18.60

Figure 4.2 – Example RAB Capital Expenditure Input

Actual Asset Disposal – As Incurred ($m Nominal)									
Year	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
OH Sub-transmission lines	-	-	-	-	0.01	0.26	-	-	-
UG Sub-transmission cables	-	0.01	0.00	0.01	0.40	-	-	-	-
OH Distribution Lines	-	3.13	1.57	1.52	5.56	-	-	-	-
UG Distribution Cables	-	-	-	-	0.36	-	-	0.00	-
Distribution Equipment	-	0.88	0.21	1.51	0.50	0.50	0.88	0.03	1.34
Substation Bays	0.86	-	0.02	0.02	-	0.50	1.13	0.00	1.23
Substation Establishment	-	-	-	-	-	-	-	-	0.00

Figure 4.3 – Example RAB Asset Disposals Input

The CPI and WACC figures were retained from the original RFM for years 2005 – 2010. The figures for 2011 – 2013 were input into the model and were taken from the Australian Bureau of Statistics (CPI figures) and the 2010 Energex determination (WACC figures).

The input of these figures can be seen in Figure 3.4 below:

Inflation and Rate of Return									
	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
Actual CPI Inflation Rate	2.30%	2.98%	2.44%	4.24%	2.47%	2.89%	3.33%	1.58%	2.50%
Actual CPI (one year lagged)	1.0000	1.0230	1.0535	1.0792	1.1249	1.1527	1.1860	1.2255	1.2449
Forecast Inflation Rate	2.08%	2.76%	2.76%	2.76%	2.76%	2.76%	2.76%	2.76%	2.76%
Forecast Inflation Cumulative Index	1.0000	1.0276	1.0560	1.0851	1.1151	1.1458	1.1775	1.2100	1.2433
Nominal WACC	8.05%	8.50%	8.50%	8.50%	8.50%	8.50%	9.72%	9.72%	9.72%
Real WACC	5.85%	5.59%	5.59%	5.59%	5.59%	5.59%	5.59%	5.59%	5.59%
Nominal WACC (fixed real time varying)	8.28%	8.73%	8.16%	10.06%	8.19%	8.64%	9.10%	7.25%	8.23%

Figure 4.4 – Example RAB CPI and WACC Input

Capital contributions have not been included in the input sheet of the RAB RFM as Energex reports the RAB inclusive of these contributions. The input of these figures in this model would cause the figures to be inconsistent with those approved by the QCA and AER. Customer contributions have been calculated from the regulatory accounts and are stated in variable DRAB13.

3) Using the figures input in step two the RFM calculates the following for each RFM asset category and each regulatory year[2]:

[2] For full details of the calculations contained in the AER Roll Forward Model refer to the “Electricity distribution network service providers Roll forward model handbook, June 2008”

- Nominal Opening Regulated Asset Base
  - Calculated as the sum of the previous year's opening RAB, net capex, regulatory deprecation, prudent additional capex (if any), foregone return on prudent additional capex (if any) and forecast assets under construction (if any). These values are all nominal.
- Nominal Actual Inflation on Opening RAB
  - Calculated as the Nominal Opening Regulated Asset Base multiplied by the CPI inflation rate.
- Nominal Actual Straight-line Depreciation
  - Calculated as the sum of the opening RAB depreciation and depreciation incurred on prior year's capex, half WACC adjusted and inflated by CPI (assuming an average mid-year capitalisation date).
- Nominal Actual Gross Capex
  - Calculated as the actual real term capex with a half year WACC adjustment, and adjusted by Actual CPI (1 year lagged).
- Nominal Actual Disposal
  - Calculated as the actual real term disposals with a half year WACC adjustment and adjusted by actual CPI (1 year lagged).

4) The figures calculated in step three then formed the variables stated in RIN Tables 4.1, 4.2 and 4.3. RIN Table 4.1 contains the aggregated RAB figures, RIN Table 4.2 disaggregates these figures into each asset category specified in the EB RIN and RIN Table 4.3 contains the yearly average RAB value of the disaggregated asset categories.

RIN Table 4.1 – Regulatory Asset Base Values

This table contains the aggregated RAB figures and are as set out below.

EB RIN Variable	RFM Calculated Figure
Opening value	Nominal Opening Regulated Asset Base
Inflation addition	Nominal Actual Inflation on Opening RAB
Straight line depreciation	Nominal Actual Straight-line Depreciation
Regulatory depreciation	Nominal Actual Inflation on Opening RAB + Nominal Actual Straight-line Depreciation
Actual additions (recognised in	Nominal Actual Gross Capex

EB RIN Variable	RFM Calculated Figure
RAB)	
Disposals	Nominal Actual Disposal
Closing value for asset value	Nominal Opening Regulated Asset Base (for next regulatory year)

RIN Table 4.2 – Asset value roll forward

This table disaggregates each of the values in RIN Table 4.1 into the individual asset categories specified in the EB RIN. These EB RIN asset categories are made up of one or more asset categories from the RFM. For the mapping of these please refer to section 4.1.7.

5) RIN Table 4.3 – Total disaggregated RAB asset values

The figures in RIN Table 4.3 are calculated as the average of the opening and closing RAB totals for each EB RIN asset category for each year and is summarised by applying the simple formula below[3].

$$Total\ Disaggreated\ RAB\ asset\ value_{y1} = \frac{Opening\ Value_{y1} + Closing\ Value_{y1}}{2}$$

The value of capital contributions is also contained in RIN Table 4.3. These values have been taken directly from the annual regulatory accounts.

6) The Written Down Value (WDV) of 110kV Circuit Breakers at 30 June 2013 was identified through the Fixed Assets Register. This value represents 12.11% of the closing RAB value for the EB RIN asset category “Distribution Substations and Transformers”. Each of the following components of “Distribution Substations and Transformers” in the EB RIN template (Consolidated) was reduced by 12.11%.

Opening value

Inflation addition

Straight line depreciation

Regulatory depreciation

Actual additions (recognised in RAB)

Disposals

Closing value for distribution substations and transformers asset value

[3] The formula is as per the EB RIN requirements, page 26 of the EB RIN Instructions and Definitions.

The corresponding increase for each component was added to the EB RIN category "Zone Substations and Transformers".

Due to the above adjustments, the asset values for Distribution Substations and Transformers (DRAB04xx), Zone Substations and Transformers (DRAB07xx), Total Asset Base (DRAB01xx) and Total Disaggregated RAB (DRAB12xx) has been reported as Estimated Information .

<u>Network Services</u>

The AER has stated that NS are defined as "a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services".

Energex does not currently specifically record NS assets. As such the RAB for NS has been derived as a subset of that for SCS and utilises the Roll Forward Model constructed above. The NS RFM is identical to SCS in its construction and calculations with only the inputs being changed in the following ways:

- The RFM 2005 base year asset values were adjusted to include only those values relating to NS. These were adjusted using the relative replacement costs of connection assets to total assets in the Energex 2005 pricing model;
- The opening 2005 forecast capex and regulatory depreciation were adjusted to those attributable only to NS; and
- The figures for capex used in the SCS RFM were adjusted to include only those values relating to NS by subtracting any capex relating to connection assets.
- As disposals for SCS assets are insignificant and would be even more so for NS assets, they have not been adjusted except for metering and low voltage services, which are connection assets and are entirely excluded.

<u>Adjustment to the opening RAB 2005</u>

1) The replacement cost of connection assets was firstly identified from the Energex pricing (Distribution Cost of Supply, DCOS) model for 2005. These replacement costs were then classified by Energex into the asset categories required for the EB RIN. The mapping of these asset categories can be seen below:

2005 Pricing Model Asset Category	EB RIN Asset Category
110/132 kV	Underground Subtransmission Cables
	OH Subtransmission Line
33 kV Bus	Substation Bays
33 kV Line	Underground Subtransmission Cables
	OH Subtransmission Line

11 kV Bus	Distribution Substation Switchgear
11 kV Line	Underground Distribution Cables
	OH Distribution Line
LV	Distribution Transformers
Services	Low Voltage Services
Meters	Metering
Relays	Low Voltage Services

As seen in the mapping above, the classifications in the 2005 pricing model did not distinguish between overhead and underground assets. To split the replacement costs of 100/132 kV, 33 kV Line and 11 kV Line into overhead and underground a percentage split was estimated from the replacement costs in the 2013 pricing model. These can be seen below:

2005 Pricing Model Asset Category	Overhead Proportion	Underground Proportion
110/132 kV	18%	82%
33 kV Line	16%	84%
11 kV Line	9%	91%

2) Once the replacement costs from the 2005 pricing model had been classified into the categories required for the EB RIN they were collated to give totals for each EB RIN asset category. These totals were then used to calculate the percentage of connection assets for each category in relation to the total RAB (Total *System* RAB was used which includes only pure distribution assets). These can be seen below:

Calculation of Connection Assets Opening RAB 2004/05		
Connection Assets in Current RIN Categories	**$**	**% over total system assets RAB excl. Meters and Low Voltage Services**
Underground Substransmission Cables	32,168,320	0.85%
OH Subtransmission Line	6,884,471	0.18%
Substation Bays	-	0.00%
Distribution Substation Switchgear	18,800,924	0.50%
Underground Distribution Cables	90,970,484	2.42%
OH Distribution Line	8,566,485	0.23%
Distribution Transformers	311,710,914	8.28%
Low Voltage Services	180,044,247	N/A
Metering	208,748,094	N/A
Total excluding Meters	**649,145,845**	
Checking	-	
Total RAB System Assets	**4,155,595,864**	
Total RAB System excl Meters & Low Voltage Services	**3,766,803,523**	
	17.23%	

Percentages were not generated for low voltage services or metering as these are 100% connection assets.

3) The percentages of connection assets for each category were then multiplied by the total value of system assets found in the SCS RFM Input tab (Asset classes 1 – 10) to obtain the values of connection assets in each category.

4) The identified connection asset values for each category were then subtracted from the opening values in the SCS Input sheet to give the opening values for network assets. These categories included:

- OH Sub-transmission lines
- UG Sub-transmission cables
- OH Distribution lines
- UG Distribution cables
- Distribution substation switchgear
- Distribution transformers

5) The entire values for low voltage services and metering assets were removed as these categories are 100% connection assets.

<u>Adjustment to the opening 2005 forecast capex and regulatory depreciation</u>

1) Actual capex figures for connection assets were generated for regulatory year 2005 using a standard constructed assets WIP (FIN027) report. This report is the basis for

capex reporting in the regulatory accounts. The following activities were identified in this report as being related to connection assets:

Capex Activities from FIN027 Report	Description
C2010	Works required to connect individual Customers to the subtransmission (132,110 and 33 kV) and 11 kV backbone network.
C2510	Works to extend the network to connect domestic and rural customers, including subdivision works, excluding service connections.
C2550	Works to extend the network to connect commercial and industrial customers. The costs of Commercial/Industrial Customer requested extensions to the existing Distribution Network.
C2570	Construction of new services for new customers and upgraded services for existing customers. The cost of works involved in connecting customers to the distribution network. Also includes services, meters and relays

2) The total capex in these four activities was then subtracted from those asset categories identified in step four as containing connection assets. Low voltage services and metering assets were 100% excluded and as such their values were subtracted from the connection asset capex figure generated from the FIN027 report. The remaining capex for connection assets was then subtracted from the remaining identified asset classes as a proportion of their values.

3) Forecast regulatory depreciation was reduced by the percentage seen in the opening asset values between the SCS RFM and the NS RFM. The formula is summarised below:

$$Forecast\ Depreciation_{NS} = \frac{Opening\ Asset\ Value_{NS}}{Opening\ Asset\ Value_{SCS}} \times Forecast\ Depreciation_{SCS}$$

<u>Adjustment to annual capex figures</u>

The annual capex figures were adjusted in an identical manner to the forecast net capex figures in step 6 above. The total capex figures for connection assets were generated using the FIN027 report and subtracted from those asset classes determined to contain connection assets. Low voltage service and metering assets were reduced by 100% and the remaining capex was subtracted from the remaining asset categories as a proportion of their values.

The modified NS RFM workbook then calculated the figures for RIN Tables 4.1 and 4.2 in an identical manner as described for SCS. Figures for RIN Table 4.3 were also calculated as the average of the opening and closing NS RAB totals for each EB RIN asset category.

Capital Contributions

The capital contributions for NS were calculated by reducing the values for SCS by the percentage seen in the overall RAB values between SCS and NS. The formula for each year can be seen below:

$$Capital\ Contributions_{NS} = \frac{RAB_{NS}}{RAB_{SCS}} \times Capital\ Contributions_{SCS}$$

Adjustment to the Network Services template for 110KV Circuit Breakers

The NS assets are a subset of SCS and are derived by deducting calculated connection assets from the SCS assets. In calculating the opening value of the connection assets for 2005, the only connection assets are 11KV Bus and there is no 110KV Circuit Breakers. Therefore, the amounts adjusted in the "Distribution Substations and Transformers" and the "Zone Substations and Transformers" for the SC S template were applied to the NS template. For more details refer to Approach section above.

Alternate Control Services

ACS has only existed in Energex from regulatory year 2011. From their inception the ACS in Energex have contained street lighting services and more recently quoted and fee based services. As the quoted and fee based services are not based on the building block approach they are not included in the roll forward model.

The asset values for ACS were calculated using the Post Tax Revenue Model (PTRM) 5.2 used for the 2010 AER Determination. This model was built using forecast data and the template was updated with the following actual information:

- Actual capex for regulatory years 2011 – 2013 sourced from the regulatory accounts (note that the PTRM input requires real figures adjusted for inflation rather than the nominal figures).
- The ACS capex numbers for regulatory years 2011 and 2012 do not include overheads and were sourced from the workings supporting the regulatory accounts. ACS capex for 2013 was stated in the regulatory accounts inclusive of overheads and therefore no other source data was required;
- CPI figures based on those used for SCS; and
- WACC figures based on those used for SCS.

Capital contributions for ACS were sourced directly from the regulatory accounts.

4.1.4 Estimates

All data stated for NS is considered estimated information.

Data for “Distribution Substations and Transformers” and “Zone Substations and Transformers ”for SCS is considered to be estimated and consequently total Regulatory Asset Base Values are also estimated.

4.1.4.1 Justification for estimates

Energex has not measured the RAB for NS as it has not historically been required to be report this category separately.

110kV Circuit Breakers are correctly mapped to the annual RIN asset category of Distribution Substation Switchgear, which should be partially mapped to the EB RIN category of Distribution Substations and Transformers and partially to Zone Substations and Transformers. However, the detailed RFM working is based on the annual RIN asset categories.

4.1.4.2 Methodology for estimates

All data for NS was estimated by reducing the values calculated for SCS. The following amendments have been made to the SCS data to obtain the figures for NS.

- The base year asset values used in the RFM were adjusted to include estimated values relating to NS using the relative replacement cost of connection assets over total relevant system assets.
- The opening 2005 forecast capex and regulatory depreciation were reduced using an estimate of connection asset capex for 2005
- The figures for capex used in the SCS RFM were adjusted to include only those values relating to NS by subtracting an estimate of capex relating to connection assets. Disposals are only adjusted to exclude metering and low voltage services, as disposals in other asset categories were determined to be negligible.
- The capital contributions stated for NS were estimated by applying the percentage of NS RAB of SCS RAB to the SCS capital contributions figure.

For a detailed explanation of the construction of NS RAB figures please refer to section 4.1.3 above.

In relation to 110kV Circuit Breakers, an adjustment has been made based on the 30 June 2013 asset values of 110kV Circuit Breakers as a proportion of the “Distribution Substations and Transformers” category. This gives the correct closing values for the EB RIN categories of “Distribution Substations and Transformers” and “Zone Substations and Transformers”. More details are provided in the Approach section.

4.1.5 Explanatory notes

Not Applicable

4.1.6 Accounting policies

There has been no change in the Energex capitalisation policy.

4.1.6.1 Nature of the change

4.1.6.2 Impact of the change

4.1.7 RAB EB RIN Asset Category Definitions and Mapping from Annual RIN Categories to EB RIN Asset Categories

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
Overhead network assets less than 33 kV (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Distribution Lines Low Voltage Services
Underground network assets less than 33 kV (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Distribution Cables
Distribution substations including transformers	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.	Distribution Equipment Distribution Substation Switchgear Distribution Transformers
Overhead network assets 33 kV and above (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Sub-Transmission Lines
Underground network assets 33 kV and above (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Sub-Transmission Lines
Zone substations and transformers	Sites housing transformers involved in transforming power from high voltage input supply either directly from a TNSP or from Energex's own higher voltage lines - to distribution level voltages (eg 66 kV to 22 kV). This transformation can involve one step or multiple steps.	Substation Bays Substation Establishment Zone Transformers Buildings (System) Land (System)
Easements	An electricity easement is the right held by Energex to control the use of land near aboveground and underground power lines and substations. It holds this right to ensure the landowner's safety and to allow staff access to	Easements (System)

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
	work on the power lines at all times.	
Meters	An electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device	Metering
Other assets with long lives	Assets with expected asset lives greater than or equal to 10 years that are not: • Overhead Distribution Assets (Wires And Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations And Transformers • Easements • Meters	Communications Pilot Wires Streetlighting (Residual Rate 2 Assets) Other Equipment Control Centre - SCADA Buildings Land Equity Raising Costs Easements
Other assets with short lives	Assets with expected asset lives less than 10 years that are not: • Overhead Distribution Assets (Wires And Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations And Transformers • Easements • Meters	Communications IT Systems Office Equipment & Furniture Motor Vehicles Plant & Equipment Research and Development

4.2 Asset Lives

The AER requires Energex to provide the following information regarding asset lives for Standard Control Services (SCS), Alternate Control Services (ACS) and Network Services (NS):

Asset Lives – estimated service life of new assets

- **DRAB1401 – Overhead network assets less than 33kV (wires and poles)**
- **DRAB1402 – Underground network assets less than 33kV (cables)**
- **DRAB1403 – Distribution substations including transformers**
- **DRAB1404 – Overhead network assets 33kV and above (wires and towers / poles etc.)**
- **DRAB1405 – Underground network assets 33kV and above (cables, ducts etc.)**
- **DRAB1406 – Zone substations and transformers**
- **DRAB1407 – Meters**
- **DRAB1408 – “Other” assets with long lives**
- **DRAB1409 – “Other” assets with short lives**

Asset Lives – estimated residual service life

- **DRAB1501 – Overhead network assets less than 33kV (wires and poles)**
- **DRAB1502 – Underground network assets less than 33kV (cables)**
- **DRAB1503 – Distribution substations including transformers**
- **DRAB1504 – Overhead network assets 33kV and above (wires and towers / poles etc.)**
- **DRAB1505 – Underground network assets 33kV and above (cables, ducts etc.)**
- **DRAB1506 – Zone substations and transformers**
- **DRAB1507 – Meters**
- **DRAB1508 – “Other” assets with long lives**
- **DRAB1509 – “Other” assets with short lives**

These variables are a part of worksheet 4 – Assets (RAB) and have all been calculated using the AER Asset Base Roll Forward Model.

All data stated for SCS and NS is considered estimated information.

All data stated for alternate control services is considered actual information.

4.2.1 Consistency with EB RIN Requirements

4.2.1.1 EB RIN Requirements

The following has been specified by the AER when reporting the estimated service life of new assets:

> *"New assets are assets installed in the most recent regulatory reporting year. The expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. This may not align with the asset's financial or tax life"*

The AER has also specified the following reporting requirements for the estimated residual service life of assets:

> *"Energex must report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409) will deliver the same effective service as that asset class did at its installation date."*

The AER has also stated that information is required for regulatory years 2006 – 2013. If actual information cannot be reported then it must be estimated.

In calculation of these variables a weighted average may be required to aggregate multiple assets into a single asset category. The following has been set out by the AER with regards to providing a weighted average of asset lives:

> *"Where the categories comprise of a number of assets, asset lives for the whole category must be calculated by weighting the lives of individual assets within that category.*
>
> *Weightings must be calculated in order of preference:*
>
> 1. *On the basis of the asset's share of the RAB for the category and expected asset lives;*
> 2. *If 1 is not available, on the basis of replacement costs and expected asset lives;*
> 3. *If 1 and 2 cannot be applied, in accordance with the asset's contribution to the category's capacity (ie MVA-kms for lines and for cables and MVA for transformers).*
> 4. *The weighted average asset life of each category is as set out in Equation 1.*
>
> *Equation 1 - Weighted average asset life calculation*
>
> *Weighted average asset life for assets in category* $\boldsymbol{j} = \sum_{i=1}^{n} \frac{x_{i,j}}{RC_j} . \boldsymbol{EL_{i,j}}$
>
> *Where:*
>
> *n is the number of assets in category j*
>
> $x_{i,j}$ *is the value of asset i in category j*
>
> $EL_{i,j}$ *is the expected life of asset i in category j*

RC_j is the sum of the value of all assets in category j"

The following RAB asset categories have been specified by the AER:

"The RAB Assets are:

- *Overhead Distribution Assets (Wires And Poles)*
- *Underground Distribution Assets (Cables)*
- *Distribution Substations Including Transformers*
- *Zone Substations And Transformers*
- *Easements*
- *Meters*
- *Other Asset Items With Long Lives*
- *Other Asset Items With Short Lives"*

For a detailed list of definitions for each asset category please refer to 4.1.7.

4.2.1.2 Consistency

Asset Lives – estimated service life of new assets

Energex has stated the service life of new assets in the RAB in accordance with the AER's guidance. The figures have been based on values stated in the Roll Forward Model submitted to the AER as a part of the 2011 – 2015 determination process. This represents the estimated time where the asset is capable of delivering the same effective service as it could at installation date.

Asset Lives – estimated residual service life

Energex has stated the estimated residual service life of all RAB asset categories as the weighted average of all assets contained in that category. Similar to the estimated service lives, these figures are based on the Roll Forward Model submitted to the AER as a part of the 2011 – 2015 determination process. All weighted averages have been calculated on the assets' share of the RAB and their expected asset lives.

Energex has also divided asset life data into NS, SCS and ACS. This was done in line with the methodology outlined for RAB values (for details please refer to section 4.1).

4.2.2 Sources

All data prior to 2010 has been sourced from the Roll Forward Model prepared for the AER during the 2010 Regulatory Determination. For subsequent years the inputs to the Roll Forward Model have been sourced as follows:

- CPI information – Sourced from the Australian Bureau of Statistics data series A2325846C (eight capital cities periods March to March) in line with the AER approach and regulatory reporting;
- Asset capex and disposal – Sourced from the regulatory accounts; and

- WACC for 2011 – 2013 – Sourced from the AER 2010 determination.

RIN Table 4.4.1 Asset Lives – estimated service life of new assets		
Variable Code	**Variable**	**Source**
DRAB1401	Overhead network assets less than 33 kV (wires and poles)	Regulatory Accounts, ABS, 2010 Determination
DRAB1402	Underground network assets less than 33 kV (cables)	Regulatory Accounts, ABS, 2010 Determination
DRAB1403	Distribution substations including transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB1404	Overhead network assets 33 kV and above (wires and towers / poles etc)	Regulatory Accounts, ABS, 2010 Determination
DRAB1405	Underground network assets 33 kV and above(cables, ducts etc)	Regulatory Accounts, ABS, 2010 Determination
DRAB1406	Zone substations and transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB1407	Meters	Regulatory Accounts, ABS, 2010 Determination
DRAB1408	“Other” assets with long lives	Regulatory Accounts, ABS, 2010 Determination
DRAB1409	“Other” assets with short lives	Regulatory Accounts, ABS, 2010 Determination

RIN Table 4.4.2 Asset Lives – estimated residual service life		
Variable Code	**Variable**	**Source**
DRAB1501	Overhead network assets less than 33 kV (wires and poles)	Regulatory Accounts, ABS, 2010 Determination
DRAB1502	Underground network assets less than 33 kV (cables)	Regulatory Accounts, ABS, 2010 Determination
DRAB1503	Distribution substations including transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB1504	Overhead network assets 33 kV and above (wires and towers / poles etc)	Regulatory Accounts, ABS, 2010 Determination

RIN Table 4.4.2 Asset Lives – estimated residual service life		
Variable Code	**Variable**	**Source**
DRAB1505	Underground network assets 33kV and above (cables, ducts etc)	Regulatory Accounts, ABS, 2010 Determination
DRAB1506	Zone substations and transformers	Regulatory Accounts, ABS, 2010 Determination
DRAB1507	Meters	Regulatory Accounts, ABS, 2010 Determination
DRAB1508	"Other" assets with long lives	Regulatory Accounts, ABS, 2010 Determination
DRAB1509	"Other" assets with short lives	Regulatory Accounts, ABS, 2010 Determination

4.2.3 Methodology

Energex has produced the figures for the expected service life of new assets and the residual service life of assets based on the RAB Roll Forward Model (RFM) and Asset Life RFM produced for the AER during the 2010-2015 regulatory determination. These RFMs were extended from 2010 to 2013 using actual information from the regulatory accounts.

4.2.3.1 Assumptions

Standard service life of RAB assets is constant and equal to those specified in the 2011 - 2015 determination Roll Forward Model

4.2.3.2 Approach

<u>Standard Control Services</u>

1) The estimated service life of new assets was calculated using the standard service life published in the 2011 – 2015 determination RFM. This service life was applied to all years 2006 – 2013. The asset life categories in the 2010 determination RFM were then combined into the categories required for the EB RIN. This used an average of each of the applicable asset categories, weighted by their average RAB value over the eight years. For the mapping of the 2010 determination RFM asset categories to the EB RIN categories refer to section 4.1.7.

2) The residual service life of RAB assets was calculated using the Asset Life RFM template used for the 2010 determination. The calculations were extended to 2013 to complete the EB RIN data requirements. This template relies on

information calculated in the extended RAB RFM for SCS constructed previously in Basis of Preparation 4.1, 4.2, 4.3 (for detailed information please refer to Basis of Preparation 4.1, 4.2, 4.3). The extended Asset Life RFM template extracts the following information found in the RAB RFM for each asset category and regulatory year:

- Standard Asset Life;
- Opening RAB Value (2005);
- Opening RAB Residual Asset Life (2005);
- Acquisitions (assumed average mid-year capitalisation and adjusted for half year WACC);
- Disposals (assumed average mid-year disposal and adjusted for half year WACC);
- Depreciation; and
- Adjustments (adjustments made in 2010 for the difference between actual and forecast capex for 2005).

3) The average residual life for each asset class is calculated by rolling forward the RAB values from the prior year. This is calculated as the average of:

   - The prior year's average residual life minus one; and
   - The standard life of any new acquisitions.

   The asset lives are weighted by the RAB value of the current year's assets (prior year RAB minus disposals, depreciation and adjustments) and the newly acquired assets respectively.

4) With the residual average asset lives calculated for each regulatory year, the asset categories are then combined into the EB RIN asset categories. The EB RIN residual asset life is calculated for each year as the average of the RFM asset lives weighted by the yearly RAB value of each RFM asset category. The mapping of the RFM asset categories to the EB RIN asset categories can be found in section 4.1.7.

Network Services

1. NS are defined as a subset of SCS. A separate RAB RFM has been developed on the assumptions contained in Basis of Preparation 4-1 for NS. This is identical to SCS with the exclusion of those assets specified by the AER in the definition of Network Services contained in the Instructions and Definitions for the EB RIN (e.g. Metering assets). For details of the construction of the NS RAB RFM please refer to Basis of Preparation 4-1.

The Asset Life RFM for NS is constructed in an identical manner to that for SCS however it draws its data from the NS RAB RFM. As such the methodology for preparing the estimated service life of new assets and the residual service life of RAB assets is identical to steps 1 – 4 in SCS above.

Alternate Control Services

1) For Energex, ACS asset categorisation starts from 2011 and after its inception only includes Street Lighting assets. A separate RFM was developed for ACS using the template supplied by the AER during the 2011 – 2015 determination. This model was then updated using actual Street Lighting asset data for regulatory years 2011 – 2013 sourced from the regulatory accounts.

   In a similar fashion to SCS and NS, the developed RFM was used as the source information to calculate the estimated service life of new assets and residual service life of assets for ACS using an Asset Life RFM. The methodology of calculating these variables was identical to SCS and NS.

   For the details of the ACS RFM please refer to Basis of Preparation 4.1, 4.2, 4.3.

4.2.4 Estimates

All variables in SCS and NS are considered estimates. The residual asset lives for SCS are considered to be estimates, as the variables comprise the weighted average of the individual assets within each category.

4.2.4.1 Justification for estimates

Energex historically has not captured RAB information separately for NS.

4.2.4.2 Methodology for estimates

Network Services

The NS residual asset lives were estimated by removing connection assets from the figures developed for SCS. The RAB RFM developed for NS was based on the SCS RFM but excluded connection assets in the 2005 base year and each subsequent year's capex and disposals. For details on these calculations refer to the basis of preparation for the RAB values.

Residual asset lives were then calculated in an identical manner to SCS by extracting the values from the amended RFM for NS and rolling forward the residual asset life figures.

4.2.5 Explanatory notes

Not Applicable

4.2.6 Accounting policies

There has been no change in the Energex accounting policies relating to asset lives.

4.2.6.1 Nature of the change

4.2.6.2 Impact of the change

5 OPERATIONAL DATA

5.1 Energy Delivery

The AER requires Energex to provide the following variables relating to the delivery of energy:

DOPED01 – Total energy delivered

Energy grouping - delivery by chargeable quantity

DOPED0201 – Energy Delivery where time of use is not a determinant

DOPED0202 – Energy Delivery at On-peak times

DOPED0203 – Energy Delivery at Shoulder times

DOPED0204 – Energy Delivery at Off-peak times

DOPED0205 – Controlled load energy deliveries

DOPED0206 – Energy Delivery to unmetered supplies

Energy - received from TNSP and other DNSPs by time of receipt

DOPED0301 – Energy into DNSP network at On-peak times

DOPED0302 – Energy into DNSP network at Shoulder times

DOPED0303 – Energy into DNSP network at Off-peak times

DOPED0304 – Energy received from TNSP and other DNSPs not included in the above categories

Energy - received into DNSP system from embedded generation by time of receipt

DOPED0401 – Energy into DNSP network at On-peak times from non-residential embedded generation

DOPED0402 – Energy into DNSP network at Shoulder times from non-residential embedded generation

DOPED0403 – Energy into DNSP network at Off-peak times from non-residential embedded generation

DOPED0404 – Energy received from embedded generation not included in above categories from non-residential embedded generation

DOPED0405 – Energy into DNSP network at On-peak times from residential embedded generation

DOPED0406 – Energy into DNSP network at Shoulder times from residential embedded generation

DOPED0407 – Energy into DNSP network at Off-peak times from residential embedded generation

DOPED0408 – Energy received from embedded generation not included in above categories from residential embedded generation

Energy grouping - customer type or class

DOPED0501 – Residential customers energy deliveries

DOPED0502 – Non-residential customers not on demand tariffs energy deliveries

DOPED0503 – Non-residential low voltage demand tariff customers energy deliveries

DOPED0504 – Non-residential high voltage demand tariff customers energy deliveries

DOPED0505 – Other Customer Class Energy Deliveries

Density factors

DOEF0102 – Energy density

These variables are a part of worksheet 5 – Operational Data and are to be reported for regulatory years 2006 – 2013.

Data stated for DOPED0206 for years 2006 – 2008 has been estimated.

All other data produced is actual information.

5.1.1 Consistency with EB RIN Requirements

The AER has specified the following requirements in relation to reporting energy delivery:

Requirements (instructions and definitions)	Consistency with requirements
Energy delivered is the amount of electricity transported out of Energex's network in the relevant Regulatory Year (measured in GWh). It must be the energy metered or estimated at the customer charging location rather than the import location from the TNSP. Energy delivered must be actual energy delivered data, unless this is unavailable.	Energy delivered has been measured at the customer charging location.
Peak, shoulder and off-peak periods relate to Energex's own charging periods.	Energex only uses on and off-peak periods. Data for shoulder periods is reported as zero.
Energex must only report 'Energy Delivery where time of use is not a determinant' (DOPED0201) for Energy Delivery that was not charged for peak, shoulder or off-peak periods.	All data for DOPED0201 was not charged based on time of use.
Energex must report energy input into its network as measured at supply points from the TNSP and other DNSPs in accordance with the definitions provided in chapter 9.	All energy supplied has been measured at supply points from Powerlink and other DNSPs.
Energex is required to report energy received from Non-residential Embedded Generation by time of receipt. Energex is required to report back cast energy received from Residential Embedded Generation only if it records data for these variables (DOPED0405–DOPED0408)	Only solar generation has been reported in DOPED0405 and was measured by Energex from 2009.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report energy delivered in accordance with the category breakdown as per the definitions provided in chapter 9. The category breakdown must be consistent with the customer types reported in RIN Table 5.2.1.	The customer types are consistent to those used in RIN Table 5.2.1.

5.1.2 Sources

Variable Code	Variable	Unit	Source
DOPED01	Total energy delivered	GWh	PEACE

RIN Table 5.1.1 Energy grouping – delivery by chargeable quantity			
Variable Code	**Variable**	**Unit**	**Source**
DOPED0201	Energy Delivery where time of use is not a determinant	GWh	PEACE
DOPED0202	Energy Delivery at On-peak times	GWh	PEACE
DOPED0203	Energy Delivery at Shoulder times	GWh	PEACE
DOPED0204	Energy Delivery at Off-peak times	GWh	PEACE
DOPED0205	Controlled load energy deliveries	GWh	PEACE
DOPED0206	Energy Delivery to unmetered supplies	GWh	PEACE

RIN Table 5.1.2 Energy – received from TNSP and other DNSPs by time of receipt			
Variable Code	**Variable**	**Unit**	**Source**
DOPED0301	Energy into DNSP network at On-peak times	GWh	Network Load Forecasting (NLF) Database
DOPED0302	Energy into DNSP network at Shoulder times	GWh	-
DOPED0303	Energy into DNSP network at Off-peak times	GWh	NLF

RIN Table 5.1.2 Energy – received from TNSP and other DNSPs by time of receipt			
Variable Code	**Variable**	**Unit**	**Source**
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	GWh	-

RIN Table 5.1.3 Energy – received into DNSP system from Embedded Generation by time of receipt			
Variable Code	**Variable**	**Unit**	**Source**
DOPED0401	Energy into DNSP network at On-peak times from non-residential embedded generation	GWh	NLF
DOPED0402	Energy into DNSP network at Shoulder times from non-residential embedded generation	GWh	-
DOPED0403	Energy into DNSP network at Off-peak times from non-residential embedded generation	GWh	NLF
DOPED0404	Energy received from embedded generation not included in above categories from non-residential embedded generation	GWh	-
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	GWh	PEACE
DOPED0406	Energy into DNSP network at Shoulder times from residential embedded generation	GWh	-
DOPED0407	Energy into DNSP network at Off-peak times from residential embedded generation	GWh	-
DOPED0408	Energy received from embedded generation not included in above categories from residential embedded generation	GWh	-

RIN Table 5.1.4 Energy grouping – customer type or class			
Variable Code	**Variable**	**Unit**	**Source**
DOPED0501	Residential customers energy deliveries	GWh	PEACE
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	GWh	PEACE
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	GWh	PEACE
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	GWh	PEACE
DOPED0505	Other Customer Class Energy Deliveries	GWh	PEACE

5.1.3 Methodology

Annual energy data in the Energex Networks can be classified into two categories, based on both the energy flow features and Economic RIN 2013/14 requirement:

- Energy Delivered (ie; kWh conveyed by Energex to end users)
- Energy Purchased (ie; kWh injected into Energex Networks)

Energy delivered is reported in RIN Tables 5.1.1 and 5.1.4 and energy purchased is reported in RIN Tables 5.1.2 and 5.1.3. Each of these figures is broken down into the categories specified by the AER.

5.1.3.1 Assumptions

It is assumed that all solar power is generated inside peak periods. Due to the sunlight times there is little generation outside these times.

5.1.3.2 Approach

Total Energy Delivered

The total energy delivered by Energex to customers was extracted directly from the Energex billing system (PEACE) and aggregated by regulatory year.

Energy grouping – delivery by chargeable quantity

The calculation of each variable is summarised in the table below and figures were disaggregated using the network tariff codes. The data was separated into the separate time periods using data inherent in the source systems. Energex does not use a shoulder period and therefore zero has been recorded against these variables. Data in this table was sourced from the Energex billing system (PEACE).

RIN Table 5.1.1 Energy grouping – delivery by chargeable quantity		
Variable Code	**Variable**	**Calculation methodology**
DOPED0201	Energy Delivery where time of use is not a determinant	Sum of all residential sales excluding controlled load and solar. The residual value of energy delivered (total energy delivered minus the total of POPED0201-6) was also added to this variable.
DOPED0202	Energy Delivery at On-peak times	Sum of all energy supplied to half hourly metered customers between 7am – 9pm weekdays. This included consumption on the following NTCs: 1000, 2000, 2500, 3000, 4000, 4500, 8000, 8100, 8300, 8500 and 8800.
DOPED0203	Energy Delivery at Shoulder times	Not applicable.
DOPED0204	Energy Delivery at Off-peak times	Sum of all energy supplied to half hourly metered customers outside the period 7am – 9pm weekdays (this figure includes all times on weekends and public holidays). This included consumption on the following NTCs: 1000, 2000, 2500, 3000, 4000, 4500, 8000, 8100, 8300, 8500 and 8800.
DOPED0205	Controlled load energy deliveries	Sum of energy delivered to controlled load customers, calculated as the sum of NTCs 9000 and 9100.
DOPED0206	Energy Delivery to unmetered supplies	Sum of street lighting, watchman light and other unmetered supplies based on NTC 9600. Data for 2006 – 2008 was unavailable and was estimated by trending back figures from the later years.

Energy – received from TNSP and other DNSPs by time of receipt

Data in this table was sourced from the Network Load Forecasting database.

RIN Table 5.1.2 Energy – received from TNSP and other DNSPs by time of receipt		
Variable Code	**Variable**	**Calculation methodology**

RIN Table 5.1.2 Energy – received from TNSP and other DNSPs by time of receipt		
Variable Code	**Variable**	**Calculation methodology**
DOPED0301	Energy into DNSP network at On-peak times	Sum of all energy received to Energex connection points between 7am – 9pm weekdays.
DOPED0302	Energy into DNSP network at Shoulder times	Not applicable.
DOPED0303	Energy into DNSP network at Off-peak times	Sum of all energy received to Energex connection points outside 7am – 9pm (this includes all times on weekends and public holidays).
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	Not applicable.

Energy – received into DNSP system from Embedded Generation by time of receipt

Data in this table was sourced from the Network Load Forecasting database.

RIN Table 5.1.3 Energy – received into DNSP system from Embedded Generation by time of receipt		
Variable Code	**Variable**	**Calculation methodology**
DOPED0401	Energy into DNSP network at On-peak times from non-residential embedded generation	Sum of all energy received from embedded generators and Queensland Rail trains (regenerative braking) between 7am – 9pm weekdays.
DOPED0402	Energy into DNSP network at Shoulder times from non-residential embedded generation	Not applicable.
DOPED0403	Energy into DNSP network at Off-peak times from non-residential embedded generation	Sum of all energy received from embedded generators and Queensland Rail trains (regenerative braking) outside 7am – 9pm (this includes all times on weekends and public holidays).
DOPED0404	Energy received from embedded generation not included in above categories from non-residential embedded	Not applicable.

RIN Table 5.1.3 Energy – received into DNSP system from Embedded Generation by time of receipt		
Variable Code	**Variable**	**Calculation methodology**
	generation	
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	Sum of all solar photovoltaic generated injections. It is assumed that all solar power is generated inside peak periods. Due to the sunlight times there is little generation outside these times.
DOPED0406	Energy into DNSP network at Shoulder times from residential embedded generation	Not applicable.
DOPED0407	Energy into DNSP network at Off-peak times from residential embedded generation	Not applicable.
DOPED0408	Energy received from embedded generation not included in above categories from residential embedded generation	Not applicable.

Energy grouping – customer type or class

Data in this table was sourced from the Energex billing system (PEACE).

RIN Table 5.1.4 Energy grouping – customer type or class		
Variable Code	**Variable**	**Calculation methodology**
DOPED0501	Residential customers energy deliveries	Sum of energy deliveries to all residential customers plus energy delivered to controlled load NTCs. This included the following NTCs: 8400, 9000 and 9100
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	Calculated as the residual energy delivered to Energex customers (total energy delivered minus the total of DOPED0501, DOPED0503, DOPED0504, DOPED0505).
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	Calculated as the sum of NTCs 8100 and 8300. This includes all low voltage and peak demand charges.

RIN Table 5.1.4 Energy grouping – customer type or class		
Variable Code	**Variable**	**Calculation methodology**
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	Calculated as the sum of NTCs up to 8000. This includes all high voltage and peak demand charges.
DOPED0505	Other Customer Class Energy Deliveries	Same figure as DOPED0206. Please refer to DOPED0206 calculation methodology.

Energy density

Variable DOEF0102 – Energy density was calculated by dividing the total energy delivered to customers (variable DOPED01) by the total number of customers from RIN Table 5.2. The energy delivered was multiplied by 1000 to convert the figures to MWh. All customer numbers used in this calculation were estimated and hence the values for DOEF0102 will also be estimated.

5.1.4 Estimates

Values provided for the following variables are estimated:

- 2006–08 values for DOPED0206 – Energy delivery to unmetered supplies; and
- DOEF0102 – energy density.

It should be noted that Energex Standard Asset Customer (SAC) non-demand customers are quarterly billed and the financial year total consumption is estimated based on the data at the end of September each year. The total consumption is proportioned using a simple kWh per day figure and summated.

5.1.4.1 Justification for estimates

No data was available for watchman lights and other unmetered supplies for years 2006–08.

Customer number information is derived from estimates therefore energy density is an estimate.

5.1.4.2 Basis for estimates

These figures have been estimated using a trend back from years 2009–13.

The Basis of Preparation for customer numbers describes the methodology that underpins estimates.

5.1.5 Explanatory notes

Not Applicable

5.1.6 Accounting policies

Not Applicable

5.2 Customer Numbers

The AER requires Energex to provide the following variables relating to customer numbers:

RIN Table 5.2.1 Distribution customer numbers by customer type

DOPCN0101 – Residential customer numbers

DOPCN0102 – Non-residential customers not on demand tariff customer numbers

DOPCN0103 – Low voltage demand tariff customer numbers

DOPCN0104 – High voltage demand tariff customer numbers

DOPCN0105 – Unmetered Customer Numbers

DOPCN0106 – Other Customer Numbers

DOPCN01 – Total customer numbers

RIN Table 5.2.2 Distribution customer numbers by location on the network

DOPCN0201 – Customers on CBD network

DOPCN0202 – Customers on Urban network

DOPCN0203 – Customers on Short rural network

DOPCN0204 – Customers on Long rural network

DOPCN02 – Total customer numbers

These variables are a part of worksheet 5 – Operational Data.

All values provided for customer numbers is estimated information.

5.2.1 Consistency with EB RIN Requirements

Requirements (instructions and definitions)	Consistency with requirements
Distribution Customers for a Regulatory Year are the average number of active National Meter Identifiers (NMIs) in Energex's network in that year (except for Unmetered Customer Numbers). The average is calculated as the average of the number of NMIs on the first day of the Regulatory Year and on the last day of the Regulatory Year.	Customer numbers have been calculated as the average of the beginning and end of year figures. Totals stated exclude unmetered customer numbers.
Each NMI is counted as a separate customer. Both energised and de-energised NMIs must be counted. Extinct NMIs must not be counted.	Energex has calculated all customer numbers as the number of “active” NMIs inclusive of both “energised” and “de-energised” NMIs.

Requirements (instructions and definitions)	Consistency with requirements
For unmetered customers, the Customer Numbers are the sum of connections (excluding public lighting connections) in Energex's network that do not have a NMI and the energy usage for billing purposes is calculated using an assumed load profile (examples include bus shelters, security lighting and traffic signals where not metered). Public lighting connections must not be counted as unmetered customers. **Further clarification was obtained from the AER in an email dated 21/02/14.** "It was intended that unmetered customers (with the exception of unmetered public lighting customers) were to be included in the total of customer numbers. Subsequent to the release of the RIN we have discovered that the unmetered connections of some DNSPs have National Meter Identifiers (NMIs). For some DNSPs, all unmetered connections have NMIs. The differing treatment of unmetered connections across networks will affect the comparability of customer numbers across networks. In turn, this could potentially influence benchmarking results. In order to address this issue we request that DNSPs provide a table detailing the number of unmetered connections in their networks together with their economic benchmarking RIN responses. This table should break down the connections into the number of unmetered connections that have and have not been included in the reported number of customers in the benchmarking RIN."	Unmetered connections have been calculated as the number of customers billed by Energex (where one customer counted may have several electricity consuming assets). An additional table has also been provided stating the total number of unmetered assets as required by the AER email dated 21/02/14. The unmetered connections exclude public lighting connections but include community lighting and watchman lights. In summary one NMI is equal to one customer. Total customer numbers are inclusive of unmetered customer as per the AER email dated 21/02/14.
Energex must report Customer Numbers broken down by customer class in accordance with the categorisations specified by the AER.	Customer numbers have been broken down by customer type using the definitions specified by the AER.
Energex must report Customer Numbers broken down by network location in accordance with the category definitions provided by the AER. The locations are CBD, urban, short rural and long rural.	Customer numbers have been broken down by network location using the definitions specified by the AER.

Reconciliation of total customer figures between 5.2.1 and 5.2.2

Historically, the total number of customers broken down by customer type (RIN Table 5.2.1) does not match the total broken down by location on the network (RIN Table 5.2.2). This problem is due to reconciliation issues between the FACOM/PEACE (CIS systems) and NFM/MARS/EMAS (Network Systems) and has been ongoing for Energex for the last several years. Energex has worked hard to align these figures over time and the difference between the two sources is seen to reduce significantly through the regulatory years. A number of issues were identified as discrepancies between the two systems:

- Data integrity of the SAIDI flag in EMAS which feeds the count of included customers by location on the network

- Missing network information for customers (such as the NAP)
- PEACE counted active customers only, whereas EMAS/NFM previously counted active and de-energised customers
- The stated customer numbers have been used in the Energex Annual Reports (5.2.1) and have been provided to the QCA (5.2.2) so it was considered inappropriate to align these figures historically.

5.2.2 Sources

Three key sources of data were used to produce the number of customers by customer type. Data for variables DOPCN0101-4 were generated from the Energex PEACE system for years 2008-13. For these variables, the figures for 2007 and 2008 were extracted from FACOM where possible, otherwise they were estimated.

Data for unmetered customers is held in a separate system called SLIM. Data was only available from 2008 and data for years prior to this was estimated.

No data was input for “Other Customer Numbers”.

RIN Table 5.2.1 Distribution customer numbers by customer type or class

Variable Code	Variable	Unit	Source
DOPCN0101	Residential customer numbers	number	PEACE (2008-13) /FACOM (2006-07) “Energy forecast by class.xlsx”
DOPCN0102	Non-residential customers not on demand tariff customer numbers	number	PEACE (2008-13) /FACOM (2006-07) “Energy forecast by class.xlsx”
DOPCN0103	Low voltage demand tariff customer numbers	number	PEACE (2008-13) FRC003 Report
DOPCN0104	High voltage demand tariff customer numbers	number	PEACE (2008-13) FRC003 Report
DOPCN0105	Unmetered Customer Numbers	number	SLIM (2008-13)
DOPCN0106	Other Customer Numbers	number	Not Applicable
DOPCN01	Total customer numbers	number	PEACE (2008-13) /FACOM (2006-07)

All data relating to customer numbers broken down by location on the network was sourced from the Energex NFM system.

RIN Table 5.2.2 Distribution customer number by location on the network			
Variable Code	**Variable**	**Unit**	**Source**
DOPCN0201	Customers on CBD network	number	EMAS/NFM
DOPCN0202	Customers on Urban network	number	EMAS/NFM
DOPCN0203	Customers on Short rural network	number	EMAS/NFM
DOPCN0204	Customers on Long rural network	number	N / A
DOPCN02	Total customer numbers	number	EMAS/NFM

5.2.3 Methodology

The Energex customer numbers are reported from two separate systems as the breakdown of customers by customer type and network location are stored in Energex's PEACE and NFM systems respectively. The total customer numbers in these two systems do not match due to historical reconciliation issues between these two systems. This discrepancy and Energex's efforts to reconcile these figures has been outlined in the consistency section above.

The customer numbers extracted from PEACE and NFM only included "active" and "energised" customers. The "active" and "de-energised" customers were estimated separately and the numbers were added together to give the reported customer number figures. The methodology of calculating "active" and "de-energised" customers is outlined separately in section 5.2.3.2.

5.2.3.1 Assumptions

5.2.3.2 Approach

RIN Table 5.2.1 Distribution customer numbers by customer type or class

This approach required two separate PEACE reports and a report from SLIM to generate all data required. These reports extracted the number of NMIs that were classed only as active and were energised or de-energised. End-of-year data was extracted from 2005-13 as the 2005 figures were required to calculate the average number of customers for the 2006 regulatory year.

1) The total end of year customer numbers for residential vs non-residential customers was extracted from PEACE and split using the corresponding network tariff codes. For the 2005-07 regulatory years, the same end of year customer

numbers were extracted from FACOM, split by residential and non-residential customer types. Non-residential customer numbers for 2005 were unavailable and were estimated using and extrapolation of years 2006-13.

The residential figures obtained from these reports were the end-of-year figures variable DOPCN0101. However, the non-residential customer numbers included all non-residential customers regardless of demand tariffs or voltages. As such the end-of-year figures for DOPCN0102 were required to be calculated net of those customers on demand tariffs.

2) In a separate PEACE report the customer numbers for “low voltage demand tariff customers” and “high voltage demand tariff customers” were produced for years 2008-13 based on their network tariff codes. For a detailed classification of the Energex network tariff codes please refer to section 5.2.7. Data for these variables was not available for 2005-07 and were estimated using a linear extrapolation from the 2008-13 data. This data was used as the end-of-year figures for DOPCN0103 and DOPCN0104.

3) The end-of-year figures for DOPCN0102 were then calculated as the non-residential customer numbers produced in step one minus both high and low voltage customers on demand tariffs.

4) The end-of-year figures for “DOPCN0105 - Unmetered Customer Numbers” were produced from Energex’s PEACE system (MSR 296 report) for years 2011-13. Data prior to this is not considered conclusive and was estimated using a linear trend. The figures for unmetered customers are inclusive of community lighting, other UMS (e.g. bus shelters) and watchman lights but are exclusive of street lights.

5) No customers fell into the “Other customers” (DOPCN0106) classification and as such these figures are zero.

The calculation spreadsheet for end of year figures can be seen below:

Legend

- (yellow) Reported previously or worked out by NTC
- (black) No data - had to trend - chose Linear in Excel (Formulas / More Functions / Trend)

	5.2 Customer numbers **Table 5.2.1 Distribution customer numbers by customer type or class**	2006	2007	2008	2009	2010	2011	2012	2013
DOPCN0101	Residential customer numbers	1,098,529	1,122,984	1,148,268	1,167,885	1,187,768	1,204,162	1,220,365	1,235,740
DOPCN0102	Non-residential customers not on demand tariff customer numbers	105,169	107,957	110,663	110,306	111,298	111,953	113,245	111,445
	Adjusted Non-Res Non Demand customers	99,354	101,682	104,208	103,442	103,354	102,895	103,633	100,852
DOPCN0103	Low voltage demand tariff customer numbers	5,361	5,813	6,008	6,368	7,447	8,547	9,119	10,044
DOPCN0104	High voltage demand tariff customer numbers	454	462	447	496	497	511	493	549
	Total LV and HV Demand Customers to come off DOPCN0102	5,815	6,275	6,455	6,864	7,944	9,058	9,612	10,593
DOPCN0105	Unmetered Customer Numbers	2,873	2,872	2,880	2,853	2,875	2,880	2,873	2,861
DOPCN0106	Other Customer Numbers **(Subtransmission** which are to be included in total)	8	8	9	9	9	10	10	10
DOPCN01	***Total customer numbers***	1,203,706	1,230,949	1,258,940	1,278,200	1,299,075	1,316,125	1,333,620	1,347,195

6) Average customer figures were then calculated for each variable DOPCN0101-6 as the average of the beginning and end of year customer numbers (beginning customer numbers were assumed to be equal to the end of year figure of the prior regulatory year).

7) The figures for “DOPCN01 – Total customer numbers” were then calculated as the sum of all calculated customer numbers exclusive of public lighting customers.

8) An extra table was required by the AER in an email dated 24/02/14 which showed the number of unmetered customers regardless of whether they were on a NMI or not. Data was obtained in the same manner as point 4 above with figures being extracted from SLIM directly for 2008 – 2013 and being extrapolated back for years 2006 and 2007. This table has been provided as an extra table within worksheet 5 of the EB RIN spreadsheet.

RIN Table 5.2.2 Distribution customer number by location on the network

1) The customer numbers broken down by their location on the network are stored on the Energex NFM system. End-of-year figures for years 2005-13 were extracted for from NFM broken down by CBD, Urban and Rural locations. Energex does not have any customers on long rural networks and therefore all rural flagged customers are classed as short rural.

2) Average customer figures were then calculated for each variable DOPCN0201-3 as the average of the beginning and end of year customer numbers (beginning customer numbers were assumed to be equal to the end of year figure of the prior regulatory year).

3) The variable “DOPCN02 – Total customer numbers” was then calculated as the sum of customers in each network location.

The calculation spreadsheet for customers by location on the network can be seen below:

		2006	2007	2008	2009	2010	2011	2012	2013
Start period	**CBD**	2,777	3,989	4,080	3,659	3,835	4,217	3,758	3,773
Start period	**Rural**	381,364	298,698	331,966	365,615	339,767	319,208	330,246	331,335
Start period	**Urban**	755,047	871,448	859,928	850,824	913,599	964,255	982,406	1,004,885
	Total start period	1,139,188	1,174,136	1,195,974	1,220,098	1,257,201	1,287,680	1,316,411	1,339,992
End period	**CBD**	3,989	4,080	3,659	3,835	4,217	3,758	3,773	3,753
End period	**Rural**	298,698	331,966	365,615	339,767	319,208	330,246	331,335	363,116
End period	**Urban**	871,448	859,928	850,824	913,599	964,255	982,406	1,004,885	980,215
	Total end period	1,174,136	1,195,974	1,220,098	1,257,201	1,287,680	1,316,411	1,339,992	1,347,085
		05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Average	**CBD**	3,383	4,035	3,870	3,747	4,026	3,988	3,765	3,763
Average	**Rural**	340,031	315,332	348,790	352,691	329,488	324,727	330,791	347,226
Average	**Urban**	813,248	865,688	855,376	882,212	938,927	973,330	993,645	992,550
Average	**Average over period**	1,156,662	1,185,055	1,208,036	1,238,649	1,272,440	1,302,045	1,328,202	1,343,539

Addition of “active” but “de-energised” customer numbers

The total number of “de-energised” but “active” customers was obtained from reports previously submitted to the QCA. These customer totals were only available for 2012 and

2013 and figures for 2006 – 2011 were estimated by extrapolating the available figures backwards.

Once total “de-energised” but “active” customer numbers were calculated, the numbers were split into the categories required for RIN Tables 5.2.1 and 5.2.2.

For RIN Table 5.2.1 the figures were broken down using the current percentage of de-energised customers in the categories required. The current percentage split used for calculations can be seen below:

Customer Category	Percentage of de-energised but active customers
Residential customer numbers	51.77%
Non-residential customers not on demand tariff customer numbers	47.75%
Low voltage demand tariff customer numbers	0.45%
High voltage demand tariff customer numbers	0.02%

These percentages were then applied to the total figures calculated for each regulatory year to produce an estimate of “de-energised” but “active” customers. These numbers were then added to the “active” and “energised” customers to obtain a total customer number figure.

For RIN Table 5.2.2 the total figures were split using the known percentage of customers on either CBD, urban or rural feeders in each regulatory year. The percentages used can be seen below.

Feeder Category	2006	2007	2008	2009	2010	2011	2012	2013
CBD	0.30%	0.34%	0.32%	0.31%	0.32%	0.30%	0.28%	0.28%
Urban	30.62%	28.25%	29.05%	28.47%	25.89%	24.94%	24.90%	25.84%
Short Rural	69.09%	71.41%	70.64%	71.22%	73.79%	74.76%	74.81%	73.88%

The customer numbers calculated from these percentages were then added to the “active” and “energised” customers to obtain total customer figures.

For table 5.2.3, each NMI counts as one connection and the row below has additional connections, as one NMI can have many devices associated with it.

For devices, this information comes from SLIM (Street Light Inventory Management). For NMIs, refer to notes against DOPCN0105.

Data for devices was available back to 2008. A linear trend was used to trend back for 2006 and 2007.

Note: Energex does not have any Unmetered Supply connections without NMIs. A NMI is required so Energex can Network Bill for consumption.

	2006	2007	2008	2009	2010	2011	2012	2013
UMS NMI Total	2,832	2,830	2,827	2,825	2,822	2,821	2,815	2,803
UMS additional connections	14,103	14,295	14,414	14,625	14,887	15,241	15,645	16,026

5.2.4 Estimates

Due to the estimation of "active" but "de-energised" customers all data stated for customer numbers is estimated information.

Estimation was also required specifically for the following figures:

- DOPCN0102 (2006 only)
- DOPCN0103 (2006 and 2007)
- DOPCN0104 (2006 and 2007)
- DOPCN0105 (2006 and 2007)

5.2.4.1 Justification for estimates

Estimates were required for "active" but "de-energised" customers as values for these customers and their breakdown into the categories required for the EB RIN are not recorded.

Estimates were required for DOPCN0102-5 (2006 and 2007) as data was not available. This was due to Energex moving to the PEACE system in 2008.

5.2.4.2 Basis for estimates

The only figures available for "active" but "de-energised" customers were totals for 2012 and 2013 stated in reports to the QCA. The total figures for 2006 – 2011 were estimated by extrapolating back the figures for 2012 and 2013. The breakdown of these totals for RIN Table 5.2.1 was estimated by using the current percentage split of "active" but "de-energised" customers into the required categories. The breakdown of the totals for RIN

Table 5.2.2 was also estimated by the percentage split of “active” and “energised” customers for each year. For details please refer to section 5.2.3.2

The percentage of de-energised customer across the Energex network is considered to be relatively static, even though the NMIs in this pool change as customers are energised and de-energised.

The estimated figures for DOPCN0102-5 (2006 and 2007) were calculated by extrapolating back the actual customer numbers found in subsequent regulatory years. The extrapolation was done using the least squares method.

5.2.5 Explanatory notes

Not applicable.

5.2.6 Accounting policies

Not applicable.

5.2.7 Energex Network Tariff Code Classifications

Network Tariff Code (NTC)	Type 1 Classification	Type 2 Classification
7600	Domestic	LV – residential
8400	Domestic	LV – residential
8900	Domestic	LV – residential
9000	Domestic	LV – residential
9100	Domestic	LV – residential
1000	Non-domestic	HV Demand
2000	Non-domestic	HV Demand
2500	Non-domestic	HV Demand
3000	Non-domestic	HV Demand
3500	Non-domestic	HV Demand
4000	Non-domestic	HV Demand
4500	Non-domestic	HV Demand
8000	Non-domestic	HV Demand

Network Tariff Code (NTC)	Type 1 Classification	Type 2 Classification
8100	Non-domestic	LV Demand - non-residential
8200	Non-domestic	LV Demand - non-residential
8300	Non-domestic	LV Demand - non-residential
8500	Non-domestic	LV - non-residential non demand
8600	Non-domestic	LV - non-residential non demand
8700	Non-domestic	LV - non-residential non demand
8800	Non-domestic	LV - non-residential non demand
9200	Non-domestic	UMS – N/A to Energex
9300	Non-domestic	UMS – Streetlights (public lighting) - excluded
9400	Non-domestic	UMS – N/A to Energex
9500	Non-domestic	UMS – Watchman Lights, included
9600	Non-domestic	UMS – Body Corporate Lighting etc, included
7500	Solar	Excluded (always with a primary NTC)
9700	Solar	Excluded (always with a primary NTC)
9800	Solar	Excluded (always with a primary NTC)
9900	Solar	Excluded (always with a primary NTC)

5.3 Annual system maximum demand

This Basis of Preparation relates to the following variables:

Annual system maximum demand characteristics at the zone substation level – MW measure

- **DOPSD0101 - Non-coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0102 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0103 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0104 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0105 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0106 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

Annual system maximum demand characteristics at the transmission connection point – MW measure

- **DOPSD0107 - Non-coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0108 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0109 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0110 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0111 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0112 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

Annual system maximum demand characteristics at the zone substation level – MVA measure

- **DOPSD0201 - Non–coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0202 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0203 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0204 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0205 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0206 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

Annual system maximum demand characteristics at the transmission connection point – MVA measure

- **DOPSD0207 - Non–coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0208 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0209 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0210 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0211 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**

- **DOPSD0212 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

These variables are part of worksheet 5 – Operational Data.

Density factors

- **DOEF0103 – Demand density**

Weather stations

- **DOEF04001 - Amberley weather station**
- **DOEF04002 - Brisbane Airport weather station**
- **DOEF04003 - Archerfield Airport weather station**
- **DOEF04004 - Coolangatta weather station**
- **DOEF04005 - Maroochydore Airport weather station**

Density factors is part of RIN Table 8.1 and weather stations are a part of RIN Table 8.4 in worksheet 8 – Operating Environment

The values provided for all variables are actual data.

5.3.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
RIN Tables 5.3.1 to 5.3.4 must be completed in accordance with the definitions in chapter 9.	Demonstrated in section 5.3.3.2 (Approach).
Energex must provide inputs for these cells if it has calculated historical Weather Adjusted Maximum Demand.	Demonstrated in section 5.3.3.2 (Approach).
For RIN Table 5.3.1 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% Probability of Exceedance (POE) levels.	Demonstrated in section 5.3.3.2 (Approach).
For RIN Table 5.3.2 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in section 5.3.3.2 (Approach).
For RIN Table 5.3.3 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in section 5.3.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
For RIN Table 5.3.4 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in section 5.3.3.2 (Approach).
Coincident Raw System Annual Maximum Demand is the actual, unadjusted (i.e. not weather normalised) summation of actual raw demands for the requested asset level (either the zone substation or transmission connection point) at the time when this summation is greatest. The Maximum Demand does not include Embedded Generation.	Demonstrated in section 5.3.3.2 (Approach). Energex does not include Embedded Generation in its calculation of Maximum Demand.
Coincident Weather Adjusted System Annual Maximum Demand 10% POE is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 10 per cent POE level at the time when this summation is greatest.	Demonstrated in section 5.3.3.2 (Approach).
Coincident Weather Adjusted System Annual Maximum Demand 50% POE is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 50 per cent POE level at the time when this summation is greatest.	Demonstrated in section 5.3.3.2 (Approach).
Maximum Demand is as defined in the NER	*Maximum Demand* is defined in the Rules and applied by Energex as meaning - the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.

Requirements (instructions and definitions)	Consistency with requirements
Non–Coincident Raw System Annual Maximum Demand is the actual unadjusted (i.e. not weather normalised) summation of actual raw annual Maximum Demands for the requested asset level (either the zone substation or transmission connection points) irrespective of when they occur within the year. This Maximum Demand is not to be adjusted for Embedded Generation.	Demonstrated in section 5.3.3.2 (Approach). Energex does not include Embedded Generation in its calculation of Maximum Demand.
Non–Coincident Weather Adjusted System Annual Maximum Demand 10% POE This is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 10 per cent POE level irrespective of when they occur within the year.	Demonstrated in section 5.3.3.2 (Approach).
Non–Coincident Weather Adjusted System Annual Maximum Demand 50% POE is the summation of Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 50 per cent POE level irrespective of when they occur within the year.	Demonstrated in section 5.3.3.2 (Approach).
Probability of Exceedance (POE) is the probability that the actual weather circumstances will be such that the actual Maximum Demand experienced will exceed the relevant maximum demand measure adjusted for weather correction.	Demonstrated in section 5.3.3.2 (Approach).
Energex must input the weather station number, post code, suburb/locality for all weather stations in its service area.	Demonstrated in section 5.3.3.2 (Approach).
Where Energex considers weather data from a weather station is not relevant to the management of its network, Energex must input a 'no' in the 'Materiality' column and provide supporting evidence (in its Basis of Preparation) as to why the weather station is not relevant. For all other weather stations Energex must input a 'yes' in the 'Materiality' column.	Weather data from all five stations was relevant
Demand Density is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network	Demonstrated in section 5.3.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
Energex must input a variable code for each weather station (for example, DEF03001 for the first weather station). Energex must add (or remove) rows from RIN Table 8.4 such that all weather stations within its network will be included.	Rows have been added to the Data Template and appropriately coded

5.3.2 Sources

The SIFT database, Probability of Exceedance (POE) tool and Connection Point Temperature Adjusted Tool (CPTAT) were used to extract the annual maximum demand across the network at the zone substation and transmission connection point level.

The Bureau of Meteorology (BOM) was also used to source information on the weather conditions. To calculate the weather adjusted data at the zone substation level the weather data was based on five weather stations (namely Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley). To calculate the weather adjusted data at the transmission connection point level weather data was benchmarked on the Amberley weather station solely.

Data sources for the annual system maximum demand characteristics at the zone substation level – MW measure

Variable Code	Variable	Source
DOPSD0101	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0102	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/POE/BOM
DOPSD0103	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/POE/BOM
DOPSD0104	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0105	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/POE/BOM
DOPSD0106	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/POE/BOM

Data sources for the annual system maximum demand characteristics at the transmission connection point – MW measure

Variable Code	Variable	Source
DOPSD0107	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0108	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/CPTAT/BOM
DOPSD0109	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/CPTAT/BOM
DOPSD0110	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0111	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/CPTAT/BOM

Variable Code	Variable	Source
DOPSD0112	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/CPTAT/BOM

Data sources for the annual system maximum demand characteristics at the zone substation level – MVA measure

Variable Code	Variable	Source
DOPSD0201	Non–coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0202	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/POE/BOM
DOPSD0203	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/POE/BOM
DOPSD0204	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0205	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/POE/BOM
DOPSD0206	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/POE/BOM

Data sources for the annual system maximum demand characteristics at the transmission connection point – MVA measure

Variable Code	Variable	Source
DOPSD0207	Non–coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0208	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/CPTAT/BOM

Variable Code	Variable	Source
DOPSD0209	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/CPTAT/BOM
DOPSD0210	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0211	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/CPTAT/BOM
DOPSD0212	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/CPTAT/BOM

5.3.3 Methodology

5.3.3.1 Assumptions

The following assumptions apply 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 – 30/08;
- The duration of the summer period is from the 01/12 – 31/01;
- 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; and
- The weather data sourced from the Bureau of Meteorology was based on five weather stations, including Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley.

The following assumptions apply to the data used to calculate the weather adjusted data at the transmission connection point level:

- The data is based the summer period from the 01/12 – 31/01;
- The temperature 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 raw data excluded embedded generation; and
- The weather data sourced from the Bureau of Meteorology was solely benchmarked on the Amberley weather station.

5.3.3.2 Approach

The temperature adjustment process used by Energex was based on the following process:

1) The days that are unlikely to produce a peak demand were excluded.
2) Multiple seasons of data were used and then normalised to remove annual growth.
3) 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 +c)
4) 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 before aggregation.

The following approach was applied to calculate the annual system maximum demand characteristics at the zone substation level – MW and MVA (RIN Table 5.3.1 and 5.3.3):

- The demand data for each zone substation was aggregated to find for total non-coincident peak;
- Coincident demand MW and MVA were calculated using the yearly distribution losses applied to the raw connection point total demand MW and MVA. The average network losses for 11kV bus were extracted from the Energex Annual Distribution Loss Factor reports.
- The POE adjustment is based on the standard temperature adjustment process using the best fit of five BOM sites and is recorded in SIFT; and

- These adjustments are then applied to the recorded demands and then aggregated to total values in the appropriate row in MW or MVA (as appropriate).

The kVA non-coincident Maximum Demand at zone substation level (DOPSD0201) was divided by the total number of customers of the network (as calculated in accordance with section 5.2) to find demand density.

The following approach was applied to calculate the annual system maximum demand characteristics at the transmission connection point – MW and MVA (RIN Table 5.3.2 and Table 5.3.4):

- The demand data for each zone substation was aggregated to find for total non-coincident peak;

- The connection point coincident MW and MVA values were calculated from system native demand after removal of the adjustment for embedded generation operating at the coincident half hour.

- Energex has not had a consistent methodology of estimating 10Poe and 50Poe values for Connection Point demand history. Energex is still developing a temperature adjustment process similar to the AEMO recommended approach for Connection Points Due to the inconsistent methodology the POE values for Connection Points have been removed.

The non-coincident zone substation summated demands are independent on the half hour of peak therefore diversity of load peaks and losses need to be applied to produce equivalent Connection Point peak demands.

The five weather stations used to source information on the weather conditions was input into RIN Table 8.4, along with the relevant the weather station number, post code, suburb/locality. The data sourced from all five weather stations was relevant to calculations, as discussed above.

5.3.4 Estimates

5.3.4.1 Justification for estimates

Customer number information is derived from estimates therefore the demand density variable is an estimate.

5.3.4.2 Reasons for estimates

The Basis of Preparation for customer numbers describes the methodology that underpins estimates.

5.3.5 Explanatory notes

Not Applicable

5.3.6 Accounting policies

Not Applicable

5.4 Power factor conversion between MVA and MW

This Basis of Preparation relates to the following variables:

Power factor conversion between MVA and MW

- **DOPSD0301 - Average overall network power factor conversion between MVA and MW**
- **DOPSD0302 - Average power factor conversion for low voltage distribution lines**
- **DOPSD0303 - Average power factor conversion for 11 kV lines**
- **DOPSD0304 - Average power factor conversion for SWER lines**
- **DOPSD0305 - Average power factor conversion for 22 kV lines**
- **DOPSD0306 - Average power factor conversion for 33 kV lines**
- **DOPSD0307 - Average power factor conversion for 66 kV lines**
- **DOPSD0308 - Average power factor conversion for 132 kV lines**

These variables are part of worksheet 5 – Operational Data.

The values provided for all variables are actual data, except the average power factor conversions for low voltage distribution line variables are estimated data.

5.4.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the power factor to allow for conversion between MVA and MW measures for each voltage.	Demonstrated in section 5.4.3.2 (Approach).
If both MVA and MW throughput for a network are available then the power factor is the total MW divided by the total MVA. Energex must provide a power factor for each voltage level and for the network as a whole. The average overall power factor conversion (DOPSD0301) is the total MW divided by the total MVA.	Demonstrated in section 5.4.3.2 (Approach).
If either the MW or MVA measure is unavailable the average power factor conversion can be calculated as an approximation based on best engineering estimates.	Demonstrated in section 5.4.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all variables are actual data, except the average power factor conversions for low voltage distribution line variables, which are estimated data.

5.4.2 Sources

The Substation Investment Forecasting Tool (SIFT) and SCADA databases were used to extract the input data for these variables. This is outlined in the table below.

Variable Code	Variable	Unit	Source
DOPSD0301	Average overall network power factor conversion between MVA and MW	Factor	SIFT/SCADA
DOPSD0302	Average power factor conversion for low voltage distribution lines	Factor	SIFT/SCADA
DOPSD0303	Average power factor conversion for 11 kV lines	Factor	SIFT/SCADA
DOPSD0304	Average power factor conversion for SWER lines	Factor	SIFT/SCADA
DOPSD0305	Average power factor conversion for 22 kV lines	Factor	SIFT/SCADA
DOPSD0306	Average power factor conversion for 33 kV lines	Factor	SIFT/SCADA
DOPSD0307	Average power factor conversion for 66 kV lines	Factor	SIFT/SCADA
DOPSD0308	Average power factor conversion for 132 kV lines	Factor	SIFT/SCADA

5.4.3 Methodology

5.4.3.1 Assumptions

Data for 110 kV and 132 kV was combined given the similarities of these lines from a technical perspective.

The methodology and justification for the low voltage distribution line power factor conversion is discussed is section 5.4.3.2.

5.4.3.2 Approach

The following approach was applied to calculating the relevant power factor conversion variables:

- Average power factor was calculated using the summated MVA and summated MW at the system level. All data for these calculations was extracted from SCADA;
- Power factor at the132/110 kV line level was calculated using the actual MVA and MW at the connection points;
- Power factor at the 33 kV line level was calculated using the actual MVA and MW at the Bulk Supply substations;
- Power factor at the 6.35 kV SWER line level was calculated using the actual MVA and MW at the Somerset Dam Zone Substation;
- Power factor at the 11 kV line level was calculated using the actual MVA and MW at the Zone substations; and
- Power factor at LV line level was estimated using the difference between the average power factor at the bulk supply level and the average power factor at the zone substation level and applying this difference to the Zone substation values. Verification of typical pf at LV was undertaken using 1600 distribution transformers from across the Energex network.

5.4.4 Estimates

5.4.4.1 Justification for estimates

The required historical data at the low voltage distribution lines was not previously recorded and therefore was not available.

5.4.4.2 Basis for the estimates

The low voltage average power factor was estimated to be twice the difference between the 11 kV and 33 kV power factor because the actual power factor at the LV is known and is likely to be worse than the 11 kV network due to compensation at the 11 kV bus of most zone substations.

5.4.5 Explanatory notes

Not Applicable.

5.4.6 Accounting policies

Not Applicable.

5.4.6.1 Nature of the change

Not Applicable.

5.4.6.2 Impact of the change

Not Applicable.

5.5 Demand supplied

This Basis of Preparation relates to the following variables:

Demand supplied (for customers charged on this basis) – MW measure

- **DOPSD0401 - Summated Chargeable Contracted Maximum Demand**
- **DOPSD0402 - Summated Chargeable Measured Maximum Demand**

Demand supplied (for customers charged on this basis) – MVA measure

- **DOPSD0403 - Summated Chargeable Contracted Maximum Demand**
- **DOPSD0404 - Summated Chargeable Measured Maximum Demand**

These variables are part of worksheet 5 – Operational Data.

The values provided are actuals.

5.5.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex is only required to complete RIN Table 5.3.6 if it charges customers for Maximum Demand supplied. If Energex does not charge customers on this basis then Energex should enter '0'.	Demonstrated in section 5.5.3.2 (Approach).
Energex must report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MW. Where Energex cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.	Demonstrated in section 5.5.3.2 (Approach).
Energex is only required to complete RIN Table 5.3.7 if it charges customers for demand supplied. If Energex does not charge customers on this basis then Energex must enter '0'.	Demonstrated in section 5.5.3.2 (Approach).
Energex must report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MVA. Where Energex cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.	Demonstrated in section 5.5.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
Maximum Demand is as defined in the NER.	*Maximum Demand* is defined in the Rules and applied by Energex as meaning - the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for the MW measures are actuals, whereas the MVA measure is based on estimated contracted and measured power factor data.

5.5.2 Sources

An internal list of contracted customers, which also includes amounts of demand and dates, in addition to PEACE are the primary data sources used to calculate these variables. This is outlined in the table below.

Data source for demand supplied (for customers charged on this basis) – MW measure

Variable Code	Variable	Source
DOPSD0401	Summated Chargeable Contracted Maximum Demand	Contracted Demand Customers January 2014
DOPSD0402	Summated Chargeable Measured Maximum Demand	PEACE

Data source for demand supplied (for customers charged on this basis) – MVA measure

Variable Code	Variable	Source
DOPSD0403	Summated Chargeable Contracted Maximum Demand	List of Contracted Customers, Amount and Dates
DOPSD0404	Summated Chargeable Measured Maximum Demand	PEACE

5.5.3 Methodology

5.5.3.1 Assumptions

No assumptions were applied to calculating these variables.

5.5.3.2 Approach

The following approach was applied to calculate the variables:

- Contracted peak demand was extracted from customer contracts, with each demand being summated in MW, due to the use of kW peak demand tariffs; and
- Annual peak demand measured for those customers was summated to calculate MW.

Historically, Energex has not had kVA peak contracts due to the standard demand tariff structures.

5.5.4 Estimates

Not applicable.

5.5.5 Accounting policies

Not Applicable.

5.5.5.1 Nature of the change

Not Applicable.

5.5.5.2 Impact of the change

Not Applicable.

6 PHYSICAL ASSETS

6.1 Circuit Length

This Basis of Preparation relates to the following variables:

Overhead network length of circuit at each voltage

- **DPA0101 - Overhead low voltage distribution**
- **DPA0102 - Overhead 11 kV**
- **DPA0103 - Overhead SWER**
- **DPA0104 - Overhead 22 kV**
- **DPA0105 - Overhead 33 kV**
- **DPA0106 - Overhead 66 kV**
- **DPA0107 - Overhead 132 kV**
- **DPA01 - Total overhead circuit km**

Underground network circuit length at each voltage

- **DPA0201 - Underground low voltage distribution**
- **DPA0202 - Underground 11 kV**
- **DPA0203 - Underground 22 kV**
- **DPA0204 - Underground 33 kV**
- **DPA0205 - Underground 66 kV**
- **DPA0206 - Underground 132 kV**
- **DPA02 - Total underground circuit km**

These variables are part of RIN Table 6.1.1 and RIN Table 6.1.2 as set out in worksheet 6 – Physical Assets.

The values provided for all variables are actual data, with the exception of SWER data prior to 2013.

6.1.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex is required to report against the capacity variables for the whole network.	Demonstrated in section 6.1.3.2 (Approach).
The network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers.	Demonstrated in section 6.1.3.2 (Approach). Energex's variables do not include pilot cables as they are a secondary system, as per the definition below.

Requirements (instructions and definitions)	Consistency with requirements
The network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	Demonstrated in section 6.1.3.2 (Approach).
Specify the voltage for each ‘other’ voltage level, where applicable.	Energex does not have any other voltage levels to those specified in the AER’s RIN Instructions and Definitions.
Circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.	Demonstrated in section 6.1.3.1 (Assumptions).

All variables have been provided in accordance with the AER’s instructions and definitions.

The values provided for all variables are actuals.

6.1.2 Sources

The circuit lengths at each voltage level were extracted using the Network Facilities Management (NFM) database. This is outlined in the table below.

Data Source for overhead network length of circuit at each voltage

Variable Code	Variable	Source
DPA0101	Overhead low voltage distribution	NFM
DPA0102	Overhead 11 kV	NFM
DPA0103	Overhead SWER	NFM
DPA0104	Overhead 22 kV	NFM
DPA0105	Overhead 33 kV	NFM
DPA0106	Overhead 66 kV	NFM
DPA0107	Overhead 132 kV	NFM
DPA01	Total overhead circuit km	NFM

Data sources for underground network length of circuit at each voltage

Variable Code	Variable	Source
DPA0201	Underground low voltage distribution	NFM
DPA0202	Underground 11 kV	NFM
DPA0203	Underground 22 kV	NFM
DPA0204	Underground 33 kV	NFM
DPA0205	Underground 66 kV	NFM
DPA0206	Underground 132 kV	NFM
DPA02	Total underground circuit km	NFM

The NFM database is the master electronic record of all network assets and their connectivity. It is populated from completed field work orders and reflects the normal, as constructed state of the network.

Because practical completion is required before capture can occur, there is a delay in the capture of data. Energex currently captures approximately 90% of all records within 20 days of commissioning.

6.1.3 Methodology

6.1.3.1 Assumptions

The following assumptions and limitations apply to the data:

- Customer owned conductors were generally not captured in the NFM database. However, there were a limited number of instances where:
  - Energex operated the network through these customer assets and therefore required them to be captured; or
  - Selected assets had been sold to customers and the assets may not have been removed from the NFM. (This had an immaterial impact on the data.)

  It was identified that Energex could limit the impact customer owned conductors would have on our reported lengths by assuming that where two customer-owned assets are joined together, the conductor facilitating this connection was also customer-owned. All other instances were unable to be identified and have been included in the overall figure.

- It was identified since the last annual RIN (2012-2013) that 2x110kV feeders have been captured in error during initial data capture in 2001. This has resulted in a reduction of 44km of the 132kV overhead network through all reported years.

- The conductor data does not include conductors that are in store or held for spares.

- Due to past data issues it was impossible to historically extract SWER lengths for each year. Minimal changes have occurred to the SWER network for the last 10 years. As a result, the existing SWER lengths (as at 01/07/2013) were used for all previous years.
- The length of each conductor category was the total conductor route length and not each individual phase conductor length, noting:
  - 11 kV+ routes predominately consist of 3 conductors.11 kV routes also include single phase (2 conductors) in its total length; and
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral, however lengths provided include all variations.
- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails.

6.1.3.2 Approach

The following approach was applied to calculate the variables:

1) The data for each of the required years was obtained by running scripts through the NFM database. In particular:
   - The Line_Lengths_By_Year.sql scripts were run to extract data for each of the voltage levels (including SWER line) over the required years. The script extracted data for the overhead and underground circuit length of each voltage level; and
   - A SWER_Line_Lengths_By_Year.sql scripts were run to extract data for SWER line over the required years. The script extracted data for the overhead circuit length of the SWER lines for a given reporting period. It was identified that due to recent data correction that SWER could not be readily determined for pre 2013 years;
2) The scripts extracted the relevant data into Microsoft Excel;
3) Once all of the data was extracted into Microsoft Excel, the circuit line length data was arranged into a pivot table for each of the required years and each of the variable codes. The subtotals for each variable codes were summated and compared to the extracted NFM total value. The purpose of this is to remove all rounding errors. If there were any rounding errors, the discrepancies were added or subtracted against the largest line length for the relevant year; and
4) The data was validated by checking the results against the Energex Annual Report and Distribution Annual Planning Report (DAPR). In cases where the variance was greater than 1%, the differences would have been investigated and resolved. However, no variances of greater than 1% were identified.
5) The SWER length was then removed from DPA0102 11 kV overhead length and added to DPA0103 Overhead SWER.

6.1.4 Estimates

SWER length was estimated for all years prior to 2013. 2013 SWER length data is based on actual data.

6.1.4.1 Justification for estimates

As no material changes have occurred to the SWER network for the last 10 years it was determined that 2013 actual data provided a better indicative of the total SWER network then using the previous year's actual data.

6.1.4.2 Reasons for estimates

Data corrections to ensure that the correct number of phases and conductors are associated with each overhead span in the 2012-2013 period now allows SWER conductors to be accurately identified.

6.1.5 Explanatory notes

The figures stated for circuit length in RIN Tables 6.1.1 and 6.1.2 may differ from those used in the calculation of circuit capacity in RIN Tables 6.1.3 and 6.1.4. Data for circuit length has been reported previously on an "as constructed" basis and the same methodology has been used in these variables to ensure consistency. The circuit length used for the calculation of circuit capacities in RIN Tables 6.1.3 and 6.1.4 is on an "as operated basis". For further details of the circuit length methodology please refer to the applicable bases of preparation.

6.1.6 Accounting policies

Not Applicable

6.1.6.1 Nature of the change

Not Applicable

6.1.6.2 Impact of the change

Not Applicable

6.2 Circuit Capacity – Low Voltage Distribution

This Basis of Preparation relates to the following variables:

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0301 - Overhead low voltage distribution**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0401 - Underground low voltage distribution**

These variables are part of RIN Table 6.1.3 and RIN Table 6.1.4 as set out in worksheet 6 – Physical Assets.

The values provided are estimated data.

6.2.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in section 6.2.3.2 (Approach).
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data Template itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.
Where the peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in section 6.2.3.1 (Assumptions).

Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in section 6.2.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all variables are estimates.

6.2.2 Sources

The data sources used to estimate the relevant variables are set out in the table below.

Data Source for estimated overhead and underground network weighted average MVA capacity for low voltage distribution

Variable Code	Variable	2008 Source
DPA0301	Overhead low voltage distribution	NFM/2008 Plant Rating Manual/Conductor Catalogue
DPA0401	Underground low voltage distribution	NFM/2008 Plant Rating Manual/Conductor Catalogue

6.2.3 Methodology

6.2.3.1 Assumptions

In relation to the LV circuit line lengths used to calculate the weighted average circuit ratings, the following assumptions were made:

- Customer owned conductors were generally not captured in the Network Facilities Management (NFM) database. However, there were a limited number of instances where:
  - Energex operated the network through these customer assets and therefore required them to be captured; or
  - Selected assets had been sold to customers and the assets may not have been removed from the NFM (which had an immaterial impact on the data.)

  In these few instances Energex was unable to exclude the conductors;

- The conductor data does not include conductors that are in store or held for spares;
- The length of each conductor category was the total conductor route length and not each individual phase conductor length. In particular, LV routes predominately

consist of 4 conductors (namely 3 phases plus neutral). However, it should also be noted that lengths provided include all variations;

- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails; and
- As a single line diagram was used, where multiple conductors were present within the single line the conductor with the highest count was chosen. Where multiple different conductors were found with the same count then the last installed conductor was chosen.

These assumptions are identical to those used to prepare the LV circuit line lengths for DPA0101 and DPA0201 variables in RIN Table 6.1.1 and 6.1.2.

In addition, the following assumptions and limitations also underpin the calculation of these variables:

- Energex's LV asset level has a thermal summer voltage limiting rating (as set out in the AER's RIN Instructions and Definitions);
- Where an individual conductor was not included in the Energex Plant Rating Manual or Conductor Catalogues, the rating associated with the nearest listed conductor was used for that conductor. The impact of this assumption was immaterial on the overall data, as there was a small number of instances where this occurred and it did not relate to current standard conductors;
- Overhead (aerial) metric conductors are assumed to be strung to a conductor temperature design of 75 degrees. Conductor stringing to 75 degrees was introduced around the 1980's and is closely aligned to the introduction of metric conductors. Prior to the metric conductors, imperial conductors were used and strung to a more conservative conductor temperature of 55 degrees;
- The underground conductors were assigned a thermal summer day (inducts) rating from the Plant Rating Manual;
- A single average thermal de-rating factor for overhead conductors and a single average thermal de-rating factor for underground conductors to account for contingency loading and voltage limitations were derived from the experience of Energex planning and design staff; and
- The average thermal de-rating factors are applied globally to the conductors in the overhead and underground categories rather than identify individual LV circuits and their individual limiting conductors. The values are therefore based on estimated data.

6.2.3.2 Approach

The following approach was applied to calculating the variables:

1) Low voltage (LV) circuit line lengths were obtained by conductor description for overhead and underground for each regulatory year from 2006 to 2013 (this data is discussed in the Basis of Preparation for circuit lengths). The circuit line length / conductor data was cross checked for consistency with the total lengths data for overhead and underground conductors provided in the RIN;

2) The conductor rating table was created. This was undertaken by:

   a. Assigning a thermal rating to each conductor type/size (based on its description) using the Energex Plant Rating Manual or Conductor Catalogues (if necessary);

   b. For all overhead conductors listed in the Plant Rating Manual, the summer day thermal ratings for Category A sub-circuits for 55 degrees and 75 degrees conductor temperature stringing were extracted;

   c. All overhead conductors were classified with ratings extracted from the Plant Rating Manual as either "imperial" or "metric" conductor;

   d. A Category A 55 degree rating was assigned to overhead "imperial" conductors and a Category A 75 degree rating was assigned to overhead "metric" conductors; and

   e. For overhead conductors not listed in the Plant Rating Manual a summer day thermal rating with reference to the Olex Aerial Catalogue March 1999 and Nexan's Handbook 2003 Edition was assigned for the nearest stringing conductor temperature of 75 degrees;

3) The overhead and underground average thermal de-rating factors were determined. This involved estimating the thermal de-rating factors for LV overhead and underground designed networks to account for contingency load and voltage limitations;

4) The average thermal de-rating factors to conductors was assigned for each relevant year. This involved:

   a. Assigning the overhead and underground average thermal estimated de-rating factors to the thermal rating of each conductor (0.8 for UG and 0.7 for OH) to determine the voltage limited rating of each conductor; and

   b. Summating the voltage limited conductor rating multiplied by the length of conductor (amps times kms) for overhead and underground categories for each year;

5) The weighted average voltage limited circuit rating (Amps) for overhead and underground for each year was obtained by dividing the summated conductor rating times the length by the total length. The relevant formulas are set out below:

$$underground\ Rating\ MVA = \frac{\sum^{UG\ conductor\ types} Conductor\ type\ rating\ \times conductor\ type\ length}{System\ Total\ UG\ circuit\ length}$$

$$overhead\ Rating\ MVA = \frac{\sum^{OH\ conductor\ types} Conductor\ type\ rating\ \times conductor\ type\ length}{System\ Total\ OH\ circuit\ length}$$

6) The weighted average voltage limited circuit rating in Amps was converted to MVA by multiplying by sqrt(3) x 415V and dividing by 1,000,000.

6.2.4 Estimates

6.2.4.1 Justification for estimates

Average thermal de-rating factors for overhead and underground network do not exist as part of the normal planning / design process. Energex has a planning and supply manual which dictates all the relevant design parameters, including allowable voltage drop. As a result, these factors were developed solely to account for voltage limitations for this purpose and reflect estimated data.

6.2.4.2 Reasons for estimates

Energex's approach recognises that LV network are typically voltage constrained rather than thermal constrained. Taking the thermal ratings without any account of voltage limitations would result in an overstatement of the circuit rating values for overhead and underground networks. As a result, Energex decided to apply average de-rating factors for contingency loading and voltage limitations based on the experience of Energex planning and design staff. The ratings so derived are lower than the thermal ratings by the value of the de-rating factors.

6.2.5 Explanatory notes

Energex did some further analysis of the 2012 data to explain the impact of overhead conductor stringing temperatures on the rating. Around 20% by length of the conductor is strung to 55 degrees and the remaining 80% to 75 degrees. The 55 degree weighted average rating is 113 amps and for 75 degrees 219 amps. The overall weighted average for both conductor / stringing temperatures is 184 amps. This shows that there is almost twice the rating for conductors strung to 75 degrees compared to 55 degrees. The overall impact of the 55 degree lower rating is moderated in the overall figures by only around 20% of the conductors being 55 degree rated.

6.2.6 Accounting policies

Not Applicable.

6.3 Circuit Capacity – 11 kV and SWER

This Basis of Preparation relates to the following variables:

Circuit Capacity MVA

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0302 - Overhead 11 kV**
- **DPA0303 - Overhead SWER**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0402 - Underground 11 kV**

These variables are part of RIN Table 6.1.3 and RIN Table 6.1.4 as set out in worksheet 6 – Physical Assets.

The values provided for all variables are estimated data.

6.3.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and how this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in section 6.3.3.2 (Approach).
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	There is some variation in the terminology used in the Instructions and Definitions document. Both Maximum Demand and Capacity has been referred to. For the basis of this analysis it has been inferred that the requirement is for capacity figures.

Requirements (instructions and definitions)	Consistency with requirements
Where the peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in section 6.3.3.1 (Assumptions).
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in section 6.3.3.2 (Approach).

All variables have been provided in accordance with Energex's interpretation of the AER's instructions and definitions.

The values provided for all variables are estimates.

6.3.2 Sources

The primary information sources used to extract the necessary data to calculate the circuit capacities for 11 kV was DINIS (Distribution Network Information System) and for SWER the Network Facilities Management (NFM) database. This is outlined in the table below.

Data source for estimated overhead network weighted average MVA capacity by voltage class

Variable Code	Variable	Source
DPA0302	Overhead 11 kV	DINIS
DPA0303	Overhead SWER	NFM

Data sources for estimated underground network weighted average MVA capacity by voltage class

Variable Code	Variable	Source
DPA0402	Underground 11 kV	DINIS

Energex also used the Plant Rating Manual and the ERAT corporate ratings tool to validate the datasets and to develop estimation methods.

6.3.3 Methodology

6.3.3.1 Assumptions

The following assumptions underpin the calculation of these variables:

- 'Energex's peak' (as set out in the AER's Instructions and Definitions) was interpreted as being the system peak season, rather than the peak associated with individual assets. Therefore network capacities have been calculated based on summer day rating; and

- The circuit constraint was identified by assuming any increase in load was applied in proportion to the DINIS load flow allocated load.

6.3.3.2 Approach

The following approach was applied to calculating the variables:

- The DINIS length data was compared to the length data obtained from NFM. Discrepancies were investigated to ensure validity of both source data sets when possible;

- The DINIS constrained feeder capacity was cross-checked against the ERAT corporate ratings tool;

- Each cable segment was categorised as OH or UG;

For feeder capacity, different approaches were applied as set out below:

- For 11 kV conductors, the constrained rating (capacity) of a feeder was determined by finding the highest thermal utilisation of each cable segment in the feeder or the highest voltage drop on the feeder. These values were scaled until the thermal or voltage limited segment reached 100% capacity or would exceed the voltage drop threshold. The capacity of all conductor segments in that circuit were then calculated at the loading where no thermal or voltage limitations were exceeded along the circuit;

- For the SWER conductors, capacity was taken as the rating of the SWER isolation transformer as this was the limiting factor for the capacity of the SWER feeders. The nameplate rating of these transformers was used to represent the constraint rating for these feeders;

- For 11 kV, each segment length was then multiplied by the segment demand at the feeder's thermal or voltage limited capacity;

- For SWER, the length of conductor off each isolation transformer was multiplied by the capacity;

- The total was then divided by the total feeder UG/OH length section to obtain the weighted average MVA; and

- The formula below was applied:

$$\text{UG weighted average MVA} = \frac{\sum_N (MVA_N \times UG\_SegmentLength_N)}{Total\_UG\_SegmentLength}$$

$$\text{OH weighted average MVA} = \frac{\sum_N (MVA_N \times OH\_SegmentLength_N)}{Total\_OH\_SegmentLength}$$

Where,

MVA_N is the capacity of the segment at the constrained rating of the segment in the feeder
UG_Length_N is the total UG length (km) of segment
OH_Length_N is the total OH length (km) of segment
Total_UG_Length is the total UG feeder length in the Energex network
Total_OH_Length is the total OH feeder length in the Energex network

6.3.4 Estimates

6.3.4.1 Justification for estimates

For the 11 kV capacities, the DINIS network model and ERAT database only provide the current state of the network. No historical values are available for the DINIS network model, as this has never ben needed. However, ERAT circuit ratings are published annually in the Distribution Annual Planning Report (DAPR) and historically in the Network Management Plan (NMP). The ERAT rating is based on the feeder backbone conductors, and this is used to provide operational ratings. Furthermore, these ratings are not separated into overhead or underground components.

6.3.4.2 Basis for estimates

For the 2012/13 year capacities, load flow analysis was undertaken to identify the capacity limitation for each feeder by determining the thermal or voltage limit. This has been used to determine the weighted average capacity for the network in 2012/13.

Since a network model was not available for the years prior to 2012/13, the ERAT circuit ratings published in the DAPR and NMP were used. The ERAT circuit ratings provided an annual change in average circuit operational rating. This was used to calculate an estimate of the historic change in weighted average capacity. This estimated change was applied to both overhead and underground assets.

Where DAPR or NMP data was not able to be located in electronic archives (05/06 and 06/07) a linear trend was derived based on the available data for the remaining years.

6.3.5 Explanatory notes

Not Applicable.

6.3.6 Accounting policies

Not Applicable.

6.4 Circuit Capacity – 33 kV

This Basis of Preparation relates to the following variables:

Circuit Capacity MVA

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0305 - Overhead 33 kV**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0404 - Underground 33 kV**

These variables are part of RIN Table 6.1.3 and RIN Table 6.1.4 as set out in worksheet 6 – Physical Assets.

The information provided for all variables is estimated.

6.4.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and how this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in section 6.4.3.2 (Approach).
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data Template itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.
Where Energex's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in section 6.4.3.1 (Assumptions).

Requirements (instructions and definitions)	Consistency with requirements
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in section 6.4.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all these variables are estimates.

6.4.2 Sources

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

Data Source for estimated overhead and underground network weighted average MVA capacity for 33 kV

Variable Code	Variable	Source
DPA0305	Overhead 33 kV	ANMP, GIS/NFM, ERAT2
DPA0404	Underground 33 kV	ANMP, GIS/NFM, ERAT2

The Annual Network Management Plan (ANMP)t was previously a five year blue print based on Energex's asset management strategies and operation plans. It consisted of finer network element details of the Energex network, and provided an overview of the network's reliability performance and improvement programs.

Energex also used the following secondary data sources to validate data sets:

- SIFT or Mailbot - to investigate feeder variances in relation to past projects, the commissioning date of secondary systems relating to a feeder;
- PSS SINCAL – used to source rating, line lengths and construction data; and
- Project Scope Statements and Project Approval Reports – to investigate feeder ratings.

6.4.3 Methodology

6.4.3.1 Assumptions

The following assumptions underpin the calculation of these variables:

- 'Energex's peak' (as set out in the AER's Instructions and Definitions) was interpreted as being the system peak, rather than the peak associated with individual assets;

- In relation to feeder name discrepancies between information systems, it was assumed that all feeder names were successfully and correctly matched;
- The ANMPs released prior to 2007 only recorded 33 kV feeder information for summer periods. That is, the year the ANMP was based relates to the summer period of that year (being October to March). For example, the 2006 ANMP reflects the anticipated network conditions as of October 2006; and
- All of the results were based on energised operating voltage.

6.4.3.2 Approach

The following approach was applied to calculating the variables:

1) The feeder rating data between 2006 and 2013 was obtained from the ANMP. As stated above, the 2006 ANMP data represents the year 2007 in the AER EB RIN template, and so on. The ANMP included all feeder ratings and its demand on each feeder.

2) ANMP data for the relevant year was cross-checked using data from the previous year of ANMP data. For instance, the 2007 ANMP data was the reference point for feeders and compared to 2008 ANMP data. Any identified feeder changes or anomalies between years were investigated and validated using SIFT. Once validated, the 2008 ANMP data became the reference point for cross-checking the 2009 ANMP data. This process was repeated up to the 2012 ANMP.

3) The 2012 ANMP data was cross-checked against ERAT2 (a corporate ratings tool). ERAT2 is a live system and it reflects ratings as of the present time. This system does not store historical data. The 2012 ANMP data was verified against the latest feeder rating, any discrepancies were investigated and corrected as required.

4) As 33 kV feeders in the Energex network are point to point sub-transmission circuits. Tthe rating of a feeder is dictated by the weakest segment on that circuit. The lowest rated feeder segment was used to represent the overall constrained rating of the feeder.

5) Line length data was extracted from the GIS, because this was not required for the ANMP and therefore not collected. Based on feeder names the line length data was linked to previous ANMP data to obtain the feeder rating, and the line length split by underground and overground construction type.

6) To obtain the weighted average MVA, each feeder was divided into its respective UG and OH length components, which is recorded in the GIS.

7) Each feeder length component was then multiplied by the feeder rating for the most constrained feeder section and then aggregated.

8) The total was then divided by the total feeder UG/OH length sections to obtain the weighted average MVA. The formula below was applied:

$$\text{UG weighted average MVA} = \frac{\sum_N \left(MVA_N \times UG\_Length_N \right)}{Total\_UG\_Length}$$

$$\text{OH weighted average MVA} = \frac{\sum_N \left(MVA_N \times OH\_Length_N \right)}{Total\_OH\_Length}$$

Where,

MVA is the constrained feeder rating of feeder N
UG_Length is the total length of UG component of feeder N (km)
OH_Length is the total length of OH component of feeder N (km)
Total_UG_Length is the aggregated UG feeder length of all 33kV energised circuits in the Energex network (km)
Total_OH_Length is the aggregated OH feeder length of all 33kV energised circuits in the Energex network (km)

6.4.4 Estimates

6.4.4.1 Justification for estimates

The values provided are based on best estimates of historical data, as the actual data was not available. Line length data was extracted from the GIS because the line length data was not a requirement for the ANMP, and therefore was not collected in the past. As a result, this data was extracted from the GIS for the relevant years.

6.4.4.2 Basis for estimates

The GIS can only accurately extract data based on the latest (last known) feeder names associated with the segment. Therefore, a mapping exercise was needed to match the historical feeder name to the latest name. There have been numerous changes in the 33 kV network over the last eight years, with some complex works involving cutting and swapping feeder segments to reconfigure the network. Unlike transmission networks, changes occur frequently because of day to day distribution activities.
Project scope statements and project approval reports were used to identify these changes where possible. However, it is noted that variations can occur during construction due to unforeseen circumstances.

Furthermore, there were instances found where changes to systems and record keeping practices caused records to be overwritten rather than being archived. This means actual historical data was not available.

6.4.5 Explanatory notes

Rating Conversion

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA was done assuming nominal voltage of 33 kV.

Rating (A) x 33000 (V) x $\sqrt{3}$ = Rating (MVA)

Annual Network Management Plan (ANMP) Data

The ANMP data is subject to variance on a yearly basis due to the following:

- Changes in reporting methodologies
- Augmentation projects;
- Time lag between work completion and data system updates; and
- Annual rating reviews.

Unaccounted UG/OH lengths

There were a number of underground and overhead lengths that weren't included in the calculations of these variables. This means that the lengths reported in RIN Tables 6.1.1 and 6.1.2 are different (and higher in value). This unaccounted for lengths that were related to the following:

- Reported line lengths in RIN Tables 6.1.1 and 6.1.2 of the AER EB RIN data template are based on construction voltage rather than energised voltage, as identified in the table above. The average rating is calculated based on energised voltage. (For example, feeder IPS3A is constructed at 33 kV but energised at 11 kV. Length data consider this 33 kV construction, however, it is should be 11 kV based on energised voltage.)
- The GIS line length extract reported a number of feeders with names ending with "OLD", the lengths of these "xxxOLD" feeders are included in the corresponding feeder xxx in the calculation of average MVA.
- There are discrepancies in project timing between the rating data and line length data. Hence in some instances there are mismatches between the two data sets. Project completion dates were checked against other corporate systems, such as mailbot or SIFT, and this data was adjusted to match the actual project timing or commissioning date.
- No feeder names being allocated to the feeder length data. (For example, UNAMED626.)

The difference in lengths and their effect on the calculated figures was investigated and found to be immaterial.

6.4.6 Accounting policies

Not Applicable.

6.4.6.1 Nature of the change

Not Applicable.

6.4.6.2 Impact of the change

Not Applicable.

6.5 Circuit capacity - 110/132 kV

This Basis of Preparation relates to the following variables:

Circuit Capacity MVA

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0307 - Overhead 132 kV**
- **DPA0203 Underground 22 kV**
- **DPA0205 Underground 66 kV**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0406 - Underground 132 kV**
- **DPA0403 Underground 22 kV**
- **DPA0405 Underground 66 kV**

These variables are part of RIN Table 6.1.3 and RIN Table 6.1.4 as set out in worksheet 6 – Physical Assets.

The information provided is estimated for DPA0307 and DPA0406, with the remaining information being actual.

6.5.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and how this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in section 6.5.3.2 (Approach).
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data Template itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.

Requirements (instructions and definitions)	Consistency with requirements
Where Energex's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in section 6.5.3.2 (Approach).
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in section 6.5.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for the 110/132 kV voltage class are estimated. The values provided for the 22 kV and 66 kV voltages classes are actuals. The Energex network does not comprise 22 kV or 66 kV voltage classes, therefore the values provided for these are 0.

The 110 kV voltage class is aggregated with the 132 kV class rather than being separated out as a separate voltage category. This is because these assets are similar from a technical perspective. This is consistent with the grouping applied in the DAPR.

6.5.2 Sources

A number of primary data sources were used to derive the total installed capacity for each of the overhead and underground feeders. This is outlined in the table below.

Data Source for Overhead and Underground network weighted MVA capacity or 110/132 kV

Variable Code	Variable	Source/s
DPA0307	Overhead 132 kV	ANMP, ERAT 2, NFM/GIS
DPA0406	Underground 132 kV	ANMP, ERAT 2, NFM/GIS

The Annual Network Management Plan (ANMP) report was previously a five year blue print based on Energex's asset management strategies and operation plans. It consisted of finer network element details of the Energex network and provided an overview of the network's reliability performance and improvement programs.

Energex also used the following secondary data sources to validate these data sets:

- DMS - to investigate feeder variances in relation to past projects, the commissioning date of the secondary systems components relating to a feeder;
- SIFT or Mailbot - to investigate feeder variances in relation to past projects, the commissioning date of the secondary systems components relating to a feeder;
- 1999 Plant Rating Manual – to compare the ERAT 2 feeder ratings data; and

- Historical information provided on request from Powerlink – to identify feeders which were connected with the TNSP.

6.5.3 Methodology

6.5.3.1 Assumptions

The following assumptions underpin the calculation of these variables:

- 'Energex's peak' (as set out in the AER's Instructions and Definitions) was interpreted as being the system peak, rather than the peak associated with individual assets;
- In relation to feeder name discrepancies between systems, it was assumed that all feeder names were successfully and correctly matched;
- The ANMPs released prior to 2012 only recorded 110/132 kV feeder information for summer periods. That is, the year the NMP was based relates to the summer period of that year (being October to March). For example, the 2006 NMP reflects the network conditions as of October 2005;
- The NMP which provides the feeder rating and its forecast loads only provide such data from 2005; and
- All of the results were based on the energised operating voltage.

6.5.3.2 Approach

The following approach was applied to calculating the variables:

1) The feeder rating data between 2006 and 2012 was obtained from the annual NMP reports. The level of confidence in the accuracy of this data was the highest compared to other potential data sources (such as models and rating systems). As stated above, the 2006 NMP data represents the year 2005 in the AER EB RIN template.

2) NMP data for the relevant year was cross-checked using data from the previous year of NMP data. For instance, the 2007 NMP data was the reference point for feeders and this was compared to 2008 NMP data. Any identified feeder changes or anomalies between years were investigated and validated using SIFT. Once validated, the 2008 NMP data became the reference point for cross checking the 2009 NMP data. This process was repeated up to the 2012 NMP.

3) The 2006 NMP data was cross-checked against ERAT2 (the corporate ratings tool). This system stores some historical data, which it was only available for the regulatory year 2005. ERAT2 data was also cross-checked against the 2005 NMP report, and compared against the 2006 NMP data. Any discrepancies were investigated and corrected.

4) To obtain the weighted average MVA, each feeder was divided into its respective UG and OH length components, which is recorded in an Excel spreadsheet.

5) Each feeder length component was then multiplied by the feeder rating for the most constrained feeder section, and then aggregated.

6) The rating of a feeder was dictated by the utilisation of the feeder section. The highest utilisation of a feeder section was used to represent the overall constrained rating of that feeder.

7) The total was then divided by the total feeder UG/OH section length to obtain the weighted average MVA. The formula below was applied:

$$\text{UG weighted average MVA} = \frac{\sum_N (MVA_N \times UG\_Length_N)}{Total\_UG\_Length}$$

$$\text{OH weighted average MVA} = \frac{\sum_N (MVA_N \times OH\_Length_N)}{Total\_OH\_Length}$$

Where,

MVA is the constrained feeder rating of feeder Fn
UG_Length is the total UG length (km) of feeder Fn
OH_Length is the total OH length (km) of feeder Fn
Total_UG_Length is the total UG feeder length in the Energex network
Total_OH_Length is the total OH feeder length in the Energex network

The table below sets out the data for a worked example.

Worked example of Overhead and Underground network weighted MVA capacity or 110/132 kV

Feeder	MVA	UG Distance (km)	OH Distance (km)	UG MVA.km	OH MVA.km
F1	173.0	0	17.8	0	3079.4
F2	84.0	0	21.2	0	1780.8
F3	215	9.3	0	1999.5	0
F4	215	5.2	0	1118	0
F5	210	6.5	1.6	1365	336
F6	210	10.0	2.4	2100	504
Total		**31**	**43**	**6582.5**	**5700.2**

UG Weighted Average MVA = $= \frac{6582.5}{31} = 212$ MVA

OH Weighted Average MVA = $= \frac{5700.2}{43} = 133$ MVA

6.5.4 Estimates

Values provided for the 110/132 kV voltage class are based on estimates.

6.5.4.1 Justification for estimates

The values provided are estimates, because these are derived using both actual and estimated input data. For most feeders, actual data was available. However, where data was not available, estimates were derived.

Energex does not store or record past history covering feeder rating data. The corporate rating system (ERAT2) only stores present rating information for all existing feeders. All de-commissioned or re-configured feeders throughout the years are not available within the system. This indirectly poses a challenge for Energex to be able to extract past history about feeder information. This has never been a requirement before.

Energex was only able to extract past feeder rating information based on previous ANMPs. However, the previous ANMP reporting methodology only focused on plant items, i.e. feeders which had a limited condition within its reporting period. If a feeder was deemed to not have a normal cyclic or an N-1 issue, the ANMP would not report the properties of that feeder because this did not yield useful information.

Hence the requirements to best estimate the feeder ratings and its period of existence using all other available history information was undertaken using the best endeavours.

6.5.4.2 Basis for estimates

The initial feeder rating estimate is based on the 2005 ANMP data set. If the feeder information was not available, the 1999 plant rating manual data was used as the basis for this estimate.

The estimated feeder ratings are then compared with current available information in ERAT2. If the ratings were similar, it can be assumed that the estimated feeder ratings were deemed true for the entire reporting period, as there were no augmentation works done to increase or decrease the capability of the feeder.

If there was a discrepancy, investigations were carried out to see when the change in ratings might have occurred. This was done through the investigation of secondary systems and the commissioning dates in DMS, cross checking commissioned projects via SIFT and comparing with all other ANMP reports. The change in ratings for a given year is then used as a reference point to continue investigating future feeder ratings.

If no other information was available, the latest rating data was used throughout past history , assuming that no augmentation works were performed to change any of the feeder configurations or characteristics.

6.5.5 Explanatory notes

The following explanations were considered relevant to the data provided.

Annual Network Management Plan (ANMP) Data Set

The ANMP data set is subject to variance on a yearly basis due to the following:

- Changes in reporting methodologies
- Augmentation projects;
- Time lag between workw completed and data systems being updated; and
- Annual rating reviews due to improved or more detailed analysis of factors.

Reduction in 132/110 kV OH length 2012 to 2013

Between 2012 and 2013 the 132/110 kV OH length reduced as some of these lines were sold during this period to Powerlink.

Reduction in OH average between 2012 and 2013

The reduction in the overhead average between 2012 and 2013 was primarily due to the following feeder changes:

- F713 (RVW) – 1km reduction in OH feeder length;
- F714 (RVW) – 1km reduction in OH feeder length;
- F820 (LGL-JBB) – 2.68km reduction in OH feeder length; and
- Some minor length reduction on feeders throughout the network (approximately 432m in total).

Unaccounted UG/OH lengths

There were a number of underground and overhead lengths that weren't included in the calculations of these variables. This means that the lengths reported in RIN Tables 6.1.1 and 6.1.2 are different (and higher in value). These unaccounted for lengths that were due to the following reasons:

- De-energised lines which are still part of the Energex network, which remained in the system and were included in RIN Tables 6.1.1 and 6.1.2. However these were not included in the calculation of feeder capacity variables because they were not energised.

- No feeder names being allocated to the feeder length data. (For example, UNAMED735.)
- Feeders that are 110 kV construction but are operating at the 33 kV voltage level. (For example, feeders to FBS are 110 kV constructed but energised at 33 kV. Length data consider this 110 kV, however, it is should be 33 kV based on operating voltage. Calculations were based on operating voltage.)

The difference in lengths and their effect on the calculated figures was investigated and found to be immaterial.

6.5.6 Accounting policies

Not Applicable.

6.5.6.1 Nature of the change

Not Applicable.

6.5.6.2 Impact of the change

Not Applicable.

6.6 Distribution transformer total installed capacity

This Basis of Preparation relates to the following variables:

Distribution transformer total installed capacity

- **DPA0501 - Distribution Transformer Capacity owned by utility**
- **DPA0502 - Distribution Transformer Capacity owned by High Voltage Customers**
- **DPA0503 - Cold Spare Capacity included in DPA0501**

These variables are part of RIN Table 6.2.1 as set out in worksheet 6 – Physical Assets.

The values provided for DPA0501 are actual data for 2011-12 and 2012-13. Remaining years are estimates.

The values provided for DPA0502 are actual data.

The values provided for DPA0503 are actual data for 2011-12 and 2012-13. Remaining years are estimates.

6.6.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report total installed Distribution Transformer Capacity.	Demonstrated in section 6.6.3.2 (Approach).
The total installed Distribution Transformer Capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132 kV or 66 kV to the 22 kV or 11 kV distribution level).	Demonstrated in section 6.6.3.2 (Approach).
The capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).	Demonstrated in section 6.6.3.2 (Approach).
The measure includes Cold Spare Capacity of Distribution Transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Demonstrated in section 6.6.3.2 (Approach).
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in section 6.6.3.2 (Approach). The data does not include forced cooling, as it is not applicable for Energex.

Requirements (instructions and definitions)	Consistency with requirements
The transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage is to be provided.	Demonstrated in section 6.6.3.2 (Approach).
Where the transformer capacity owned by customers connected at high voltage is not available, the summation of individual Maximum Demands of high voltage customers whenever they occur is required to be provided (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers.	Demonstrated in section 6.6.3.2 (Approach).
Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in section 6.6.3.2 (Approach).
A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.	Demonstrated in section 6.6.3.2 (Approach).
The Cold Spare Capacity is the capacity of spare transformers owned by Energex but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.	Demonstrated in section 6.6.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided contain both estimates and actuals.

6.6.2 Sources

The input data for the distribution transformer total installed capacity variables were extracted from the Network Facilities Management (NFM) database, PEACE and Ellipse. This is outlined in the table below.

Data source for distribution transformer total installed capacity

Variable Code	Variable	Source
DPA0501	Distribution Transformer Capacity owned by utility	NFM
DPA0502	Distribution Transformer Capacity owned by High Voltage Customers	PEACE
DPA0503	Cold Spare Capacity included in DPA0501	Ellipse

The NFM database is the master electronic record of distribution installed capacity and their connectivity. It is populated from completed field work orders and reflects the normal, as constructed state of the network.

PEACE is Energex's billing system and was used to source the input data used to calculate the distribution transformer capacity owned by high voltage customers.

Ellipse is an Enterprise Resource Planning system used by Energex to manage internal and external resources including assets, financial resources, materials, and human resources. It is grouped into sub-systems providing:

- Maintenance and repair scheduling;
- Workforce management, resource allocation, skills, training and payroll;
- Materials management and resource management; and
- Financial management.

6.6.3 Methodology

6.6.3.1 Assumptions

The following assumptions and limitations apply to the Distribution transformer capacity owned by utility data (DPA0501):

- Total installed transformer capacity (MVA) was reported using the recorded nameplate rating from NFM;
- Only the normal state of the network was taken into account;
- Only transformers recorded in NFM as connected to the network and with a nameplate rating at the time specified were included in the data;
- Non Energex owned assets were excluded from the data; and
- The capacity data includes assets that are in store or held for spares.

The following assumptions and limitations apply to the Distribution Transformer Capacity owned by High Voltage Customers data (DPA0502):

- The number of historic number of customers was correct for 2005-06. Due to a change in the billing system these historical values were unable to be validated.

The following assumptions and limitations apply to the Cold Spare Capacity included in DPA0501 (DPA0503):

- The number and mix of assets held in stores varies each day, where data is available, stock levels are as of the 30th of June each year;
- Actual data was available for 2011-12 and 2012-13 only.

- Energex does not have any transformer assets that could be described as cold capacity as per the AER definitions; and
- The capacity includes strategic spares as well as normal stock holding owned by Energex.

6.6.3.2 Approach

The following approach was applied to calculating the distribution transformer capacity owned by utility (DPA0501):

- The data was obtained by running the Capacity_DTx_By_Year.sql. script through the NFM database for each of the required years;
- The data was then combined into a master document and arranged into the AER template format;
- The data was validated via checking the results against the Energex Annual Report and Distribution Annual Planning Report. In cases where the variance was greater than 1 percent, the differences would have been investigated and resolved. However, no variances of greater than 1 percent were identified; and
- Cold spare capacity was added to the annual values to give total distribution transformer capacity owned by Energex.

The following approach was applied to calculating the Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- As the transformer capacity owned by customers at high voltage was largely not available, the calculation was based on the recorded annual peak demand; and
- Where capacities were available these values were used.

The following approach was applied to calculating the Cold spare capacity included in DPA0501 (DPA0503):

- The data was obtained through the ECA101 inventory report, this report is generated from a database containing daily snapshots of inventory held in Ellipse;
- Distribution transformer assets were extracted from the ECA101 report for the 30th of June each year;
- Distribution transformer capacity was extracted from the stock code description; and
- For years prior to 2011-12, Energex calculated an average based on recent inventory levels.

6.6.4 Estimates

6.6.4.1 Justification for estimates

Values used for Cold spare capacity included in DPA0501 (DPA0503), from 2005-06 to 2010-11 are estimates due to the reliance on daily inventory snapshots which were not recorded by Energex prior to February 2012.

Values used for Distribution Transformer Capacity owned by utility (DPA0501), from 2005-06 to 2010-11 are estimates due to the reliance estimates calculated for cold spare capacity.

6.6.4.2 Basis for the estimates

The primary data source for cold spare capacity is the ECA101 inventory report. Values prior to 2012 have been estimated by taking the average inventory levels over 4 days, being:

- 30th June 2012,
- 31st December 2012,
- 30th June 2013 and
- 31st December 2013.

6.6.5 Explanatory notes

Energex stores contain both normal and strategic spares. Energex holds strategic spares for asset that are influenced by such factors as high risk, high cost, and long lead delivery time. Strategic spare capacity should stay relatively constant over time and is influenced less by the daily transactions of normal spares. In back casting historic cold spare capacity, Energex has calculated the average capacity of distribution transformers held in stores in 2012 and 2013. The table below highlights the variability of spares holding over a two year period.

Average distribution transformer cold spare capacity MVA

	Cold spare distribution transformer capacity (MVA)				
Inventory date	30/06/2012	31/12/2012	30/06/2013	31/12/2013	Average
Normal spares	119.0	97.8	62.4	47.3	81.6
Strategic spares	2.5	2.0	2.0	3.0	2.4
Total spares	121.5	99.8	64.4	50.3	84.0

6.6.6 Accounting policies

Not Applicable

6.7 Zone substation transformer capacity

This Basis of Preparation relates to the following variables:

Zone substation transformer capacity

- **DPA0601 - Total installed capacity for first step transformation where there are two steps to reach distribution voltage**
- **DPA0602 - Total installed capacity for second step transformation where there are two steps to reach distribution voltage**
- **DPA0603 - Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage**
- **DPA0604 - Total zone substation transformer capacity**
- **DPA0605 - Cold spare capacity of zone substation transformers included in DPA0604**

These variables are part of RIN Table 6.2.2 as set out in worksheet 6 – Physical Assets.

The values provided for variables DPA0601, DPA0602 and DPA0603 are actuals from 2008-09 to 2012-13. Remaining years are estimates.

Information is provided for variables DPA0604 and DPA0605 are actuals for 2011-12 and 2012-13. Remaining years are estimates

6.7.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the transformer capacity used for intermediate level transformation capacity in either one or two steps.(For example, high voltages such as 132 kV, 66 kV or 33 kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6 kV.)	Demonstrated in section 6.7.3.2 (Approach).
These measures are required to be the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included) and include both energised transformers and Cold Spare Capacity.	Demonstrated in section 6.7.3.2 (Approach).
Where available, the assigned rating must be determined from results of temperature rise calculations from testing. Otherwise the nameplate rating is to be provided. For those zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders should be reported instead of transformer capacity.	Demonstrated in section 6.7.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
The total installed capacity for first step transformation where there are two steps to reach distribution voltage (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or 11 kV where there will be a second step transformation before reaching the distribution voltage. This variable is only relevant where Energex has more than one step of transformation, if this is not the case Energex must enter '0' for this variable.	Demonstrated in section 6.7.3.2 (Approach).
The total installed capacity for second step transformation is required to be reported where there are two steps to reach distribution voltage (DPA0602). (e.g. 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within Energex's system.) This variable is only relevant where Energex has more than one step of transformation, if this is not the case Energex must enter '0' for this variable.	Demonstrated in section 6.7.3.2 (Approach).
The total zone substation transformer capacity where there is only a single transformation to reach distribution voltage is to be reported (DPA0603). This variable is only relevant where there is only a single step of transformation to reach distribution voltage. If there is more than one step of transformation to reach distribution voltage, the relevant capacities must be reported in DPA0601 and DPA0602.	Demonstrated in section 6.7.3.2 (Approach).
The total zone substation transformer capacity (DPA0604) is the overall total zone substation capacity regardless of whether one or two steps are used to reach the distribution voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.)	Demonstrated in section 6.7.3.2 (Approach).
The total Cold Spare Capacity included in total zone substation transformer capacity is to be provided.	Demonstrated in section 6.7.3.2 (Approach).
A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.	Demonstrated in section 6.7.3.2 (Approach).
Cold spare capacity is the capacity of spare transformers owned by Energex but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.	Demonstrated in section 6.7.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided contain both estimates and actuals.

6.7.2 Sources

The zone substation transformer total installed capacities were extracted from the Substation Investment Forecasting Tool (SIFT) and the Network Facilities Management (NFM) database and Ellipse. This is outlined in the table below.

Data source for distribution transformer total installed capacity

Variable Code	Variable	Source
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage	SIFT
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage	SIFT
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	SIFT
DPA0604	Total zone substation transformer capacity	SIFT
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	Ellipse

The NFM database is the master electronic record of distribution installed capacity and their connectivity. It is populated from completed field work orders and reflects the normal, as constructed state of the network.

Ellipse is an Enterprise Resource Planning system used by Energex to manage internal and external resources including assets, financial resources, materials, and human resources. It is grouped into sub-systems providing:

- Maintenance and repair scheduling;
- Workforce management, resource allocation, skills, training and payroll;
- Materials management and resource management; and
- Financial management.

6.7.3 Methodology

6.7.3.1 Assumptions

The following assumptions and limitations apply to the data:

- Active and hot standby substation transformer capacities have been included;
- No data has been excluded; and
- A snapshot of the data was taken at the end of each financial year.

The following assumptions and limitations apply to the Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605):

- The number and mix of assets held in stores varies each day, where data is available, stock levels are as of the 30th of June each year;
- Actual data was available for 2011-12 and 2012-13 only.
- Spare capacity includes strategic spares as well as normal stock holding owned by Energex; and
- Cold capacity includes transformers that are in service but do not carry load under normal conditions.

6.7.3.2 Approach

The following approach was applied to calculating the variables:

- The data was extracted from SIFT as at June each year and based on Normal Cyclic rating which Energex uses to operate the network;
- The rating includes fans and allows for the load temperature rise test determine by the load profile;
- The following assets meet the definitions presented by the AER:
  - For DPA0601: 110 kV-33 kV or 132 kV-33 kV substations are a first step transformation where there are two steps to reach distribution voltage. These are referred to as bulk supply substations;
  - For DPA0602: 33 kV-11 kV substations are a second step transformation where there are two steps to reach distribution voltage. These are referred to as zone substations;
  - For DPA0603: 110 kV-11 kV or 132 kV-11 kV substations are a single step transformation to reach distribution voltage. These are referred to as direct transformation substations;
  - For DPA0604: the total capacities were the summation of all zone, bulk and direct transformation substation capacities; this also includes Cold Spare Capacity.
  - Cold capacity calculated for DPA0605 was subtracted from the SIFT extract to provide the final capacity value for DPA0601, DPA0602 and DPA0603.

Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605) incorporates both cold capacity and spare capacity:

- The approach for calculating spare capacity was as follows:
  - The data was obtained through the ECA101 inventory report, this report is generated from a database containing daily snapshots of inventory held in Ellipse;

- Power transformer assets were extracted from the ECA101 report for the 30th of June each year;
- Power transformer capacity was extracted from the stock code description; and
- For years prior to 2011-12, Energex calculated an average based on recent inventory levels.

- The approach for calculating cold capacity was as follows:
  - The data was extracted from SIFT as at June each year and based on Normal Cyclic rating which Energex uses to operate the network;
  - The extract provided the standby capacity available at each substation.

6.7.4 Estimates

6.7.4.1 Justification for estimates

Values used for Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605), from 2005-06 to 2010-11 are estimates due to the reliance on daily inventory snapshots which were not recorded prior to February 2012.

Values used for DPA0601, DPA0602, DPA0603 and DPA0605 from 2005-06 to 2007-08 are estimates due to reliance on the SIFT report for standby capacity which is available from 2008/9 to 2012/13.

6.7.4.2 Basis for the estimates

The primary data source for spare capacity is the ECA101 inventory report. Values prior to 2012 have been estimated by taking the average inventory levels over 4 days, being:

- 30th June 2012,
- 31st December 2012,
- 30th June 2013, and
- 31st December 2013.

The primary data source for cold capacity is a report generated through the SIFT database. Values prior to 2008-09 have been estimated by using the known cold capacity in 2008-09.

6.7.5 Explanatory notes

Energex stores contain both normal and strategic spares. Energex holds strategic spares for asset that are influenced by such factors as high risk, high cost, and long lead delivery time. Strategic spare capacity should stay relatively constant over time and is influenced less by the daily transactions of normal spares. In back casting historic cold spare capacity, Energex has calculated the average capacity of distribution transformers held in stores in 2012 and 2013. The table below highlights the variability of spares holding over a two year period.

Average zone substation transformer spare capacity MVA

	Zone Substation Transformer Spare Capacity (MVA)				
Inventory date	30/06/2012	31/12/2012	30/06/2013	31/12/2013	Average
Normal Spares	5.0	35.0	135.0	110.0	71.3
Strategic	292.8	304.0	339.0	339.0	318.7
Total Spares	297.8	339.0	474.0	449.0	389.9

Energex utilises a number of transformers in standby configurations where a transformer is in service but does not carry load under normal conditions. In this configuration the transformers are commissioned, connected to the network and only require switching (manual, remote or automatic) in order to carry load. The calculation of these variables required inputs to be disaggregated in order to separate standby (cold) capacity from total installed capacity. An example of this calculation is shown in the table below.

Calculation of Total zone Substation transformer capacity for 2012/13

Variable Code	Variable	Breakdown	Units	Value
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage. i.e. 132/33 kV	In service	MVA	7874.0
		Standby (cold capacity)	MVA	-81
		total	**MVA**	7793
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage. i.e. 33/11 kV	In service	MVA	7925.2
		Standby (cold capacity)	MVA	-310
		total	**MVA**	7615
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage. i.e. 110/11 kV	In service	MVA	3369.7
		Standby (cold capacity)	MVA	-86
		total	**MVA**	3284
DPA0604	Total zone substation transformer capacity	**total**	**MVA**	19643
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	Total standby capacity for first step transformation where there are two steps to reach distribution voltage	MVA	81
		Total standby capacity for second step transformation where there are two steps to reach distribution voltage	MVA	310.38
		Total standby zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	MVA	85.5
		Strategic spares	MVA	339.0
		Normal spares	MVA	135.0
		total	**MVA**	950.9

6.7.6 Accounting policies

Not Applicable

6.8 Public lighting

This Basis of Preparation relates to the following variables:

Public Lighting

- **DPA0701 - Public lighting luminaires**
- **DPA0702 - Public lighting poles**

These variables are part of RIN Table 6.3 of worksheet 6 – Physical Assets.

The values provided for all variables are actual data.

6.8.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the number of public lighting luminaires and public lighting poles.	Demonstrated in section 6.8.3.2 (Approach).
For both variables the numbers provided must include both assets owned by Energex and assets operated and maintained by Energex but not owned by Energex.	Demonstrated in section 6.8.3.2 (Approach).
Only poles that are used exclusively for public lighting are to be included in the data.	Demonstrated in section 6.8.3.2 (Approach).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all variables are actuals.

6.8.2 Sources

The number of public lighting luminaires and poles was extracted from the Network Facilities Management (NFM) database. This is outlined in the table below.

Data sources for public lighting

Variable Code	Variable	Source
DPA0701	Public lighting luminaires	NFM
DPA0702	Public lighting poles	NFM

The NFM database is the master electronic record of the public lighting assets and their connectivity. It is populated from completed field work orders and reflects the normal, as constructed state of the network.

6.8.3 Methodology

6.8.3.1 Assumptions

The following assumptions and limitations apply to the data relating to public lighting luminaires:

- Only rating 1[4] and 2[5] streetlights have been included in this count; and
- Streetlights data does not include assets that are in store or held for spares.

The following assumptions and limitations apply to the data relating to public lighting poles:

- The pole data does not include assets that are in store or held for spares;
- Only poles with a material type of 'steel' have been included;
- Only poles with a max voltage of LV or Unknown have been included;
- All timber poles have been excluded even when only a streetlight asset is installed.

6.8.3.2 Approach

The following approach was applied to calculating the variables:

- The data was obtained by running scripts through the NFM database for each of the required years. The scripts ensured that for both variables the data extracted included both assets owned by Energex, and assets operated and maintained by Energex but not owned by Energex. Further, only poles that are used exclusively for public lighting were included in the data.
- Separate scripts were run for each of the variables.
  1. The Streetlight_By_Year.sql script was run to extract the data for the Public lighting luminaires.
  2. The Poles_Streetlight_By_Year.sql was run to extract the data for the Public Lighting Poles.
- Once all of the data was extracted into Microsoft Excel for each of the required years, the data was combined into a master document and arranged into the AER Template format.
- The data was validated via checking the results against the Energex Annual Report and Distribution Annual Planning Report. In cases where the variance was greater than 1 percent, the differences would have been investigated and resolved. However, no variances of greater than 1 percent were identified.

[4] Rating 1 - A streetlight designed, constructed, owned and operated (maintained) by Energex.
[5] Rating 2 - A streetlight where the customer designs and constructs the light which is owned, operated and maintained by Energex.

6.8.4 Estimates

Not Applicable

6.8.4.1 Justification for estimates

Not Applicable

6.8.4.2 Basis for the estimates

Not Applicable

6.8.5 Explanatory notes

Not Applicable

6.8.6 Accounting policies

Not Applicable

6.8.6.1 Nature of the change

Not Applicable

6.8.6.2 Impact of the change

Not Applicable

7 QUALITY OF SERVICES

7.1 Reliability

The AER requires Energex to provide the following network reliability measures:

- **DQS0101 - Whole of network unplanned SAIDI**
- **DQS0102 - Whole of network unplanned SAIDI excluding excluded outages**
- **DQS0103 - Whole of network unplanned SAIFI**
- **DQS0104 - Whole of network unplanned SAIFI excluding excluded outages**

As well as the following measures exclusive of major event days

- **DQS0105 - Whole of network unplanned SAIDI**
- **DQS0106 - Whole of network unplanned SAIDI excluding excluded outages**
- **DQS0107 - Whole of network unplanned SAIFI**
- **DQS0108 - Whole of network unplanned SAIFI excluding excluded outages**

These variables are a part of worksheet 7 – Quality of Services.

7.1.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Reliability data must be reported in accordance with the definitions provided in the AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified.	Reporting is in accordance with the STPIS
SAIDI (System Average Interruption Duration Index) is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the total number of Distribution Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less)."	System wide SAIDI 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.
SAIFI (System Average Interruption Frequency Index) is the total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).	System wide 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.

Requirements (instructions and definitions)	Consistency with requirements
An unplanned interruption is an interruption due to an unplanned event. An unplanned event is an event that causes an interruption where the customer has not been given the required Notice for the interruption or where the customer has not requested the outage.	Reliability data has been reported in accordance with the definitions provided in the AER's STPIS for unplanned SAIDI and SAIFI.
The SAIDI and SAIFI measures must also be reported exclusive of specific outages as defined by the AER. Excluded Outages are: • load shedding due to a generation shortfall • automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition • load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator • load interruptions caused by a failure of the shared transmission network • load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning • load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.	Exclusions of outages were performed in accordance with the AER's instructions and the STPIS Guidelines.
The MED threshold must be calculated for the 2013 Regulatory Year in accordance with the requirements in the STPIS. The MED threshold calculated for 2013 must then be applied as the MED threshold for Regulatory Years prior to 2013 for the purpose of calculating SAIDI and SAIFI exclusive of MEDs as per the STPIS.	The MED threshold calculated for 2013 regulatory year is in accordance with the STPIS definition and is applied to previous years

Data provided for 2006 are estimates because actual single loss data was not collected for 2006, necessitating the application of assumptions. Data provided for the remaining years is actual because the presentation is materially dependent on information recorded in EPM and presentation in the EB RIN is not contingent on judgements and assumptions.

7.1.2 Sources

Variable Code	Variable	Source
DQS0101	Whole of network unplanned SAIDI	EPM/NFM
DQS0102	Whole of network unplanned SAIDI excluding excluded outages	EPM/NFM
DQS0103	Whole of network unplanned SAIFI	EPM/NFM
DQS0104	Whole of network unplanned SAIFI excluding excluded outages	EPM/NFM
DQS0105	Whole of network unplanned SAIDI (excluding MEDs)	EPM/NFM
DQS0106	Whole of network unplanned SAIDI excluding excluded outages (excluding MEDs)	EPM/NFM
DQS0107	Whole of network unplanned SAIFI (excluding MEDs)	EPM/NFM
DQS0108	Whole of network unplanned SAIFI excluding excluded outages (excluding MEDs)	EPM/NFM

Reliability data was sourced from two different systems, EPM and NFM. The Customer Minutes Lost (CML) and Customers Interrupted (CI) required for the basis of the SAIDI and SAIFI calculations was sourced from Energex's corporate system EPM for years 2007 to 2013.

For 2006 the data was not stored in EPM and was accessed from the NFM corporate system. The average customer numbers used in the calculations were sourced from Energex's NFM corporate system.

7.1.3 Methodology

7.1.3.1 Assumptions

All variables have been calculated exclusive of momentary interruptions as defined in the SAIDI and SAIFI definitions as <=1 minute

7.1.3.2 Approach

1) The CML and CI figures for all outages greater than 1 min in duration were extracted from the NFM (2006) and EPM (2007 – 2013) systems and summated into a daily figure (columns [C] and [D] below).

2) The daily CML and CI figures that are to be excluded for variables DSQ0102, DSQ0104, DSQ0106 and DSQ0108 were also extracted from the same systems (columns [E] and [F] below).

An example of the working can be seen below:

[A]	[B]	[C]	[D]	[E]	[F]	[G]
FINYEA	**DATE**	**ALL CML**	**ALL CI**	**Excl CM**	**Excl CI**	**AER_CU**
2006	01/07/2005	926745.12	22670.09			1156895
2006	02/07/2005	242159.57	2664.555			1156895
2006	03/07/2005	464270.9528	8115.997			1156895

3) A yearly average customer number was extracted from the Energex NFM system and assigned to each corresponding year of CML and CI data (column [G] above).

4) The daily standard SAIDI and SAIFI figures were first calculated as $\frac{CML}{\#\,Customers}$ and $\frac{CI}{\#\,Customers}$ respectively. The daily SAIDI and SAIFI figures were then calculated with the exclusion of specific outages as stated by the AER.

These calculations can be seen in columns [H], [I], [M] and [N] below:

[H]	[I]	[J]	[K]	[L]	[M]	[N]
DQS0101	DQS0103				DQS0102	DQS0104
ALL SAIDI	**ALL SAIFI**	**Excl SAIDI**	**Excl SAIFI**	**Excl Flag**	**All SAIDI Less Excl**	**All SAIFI Less Excl**
0.80106243	0.01959563	0	0	NO	0.80106243	0.01959563
0.20931854	0.0023032	0	0	NO	0.209318538	0.0023032
0.40130777	0.00701533	0	0	NO	0.40130777	0.00701533

5) The daily SAIDI and SAIFI figures were then aggregated per financial year to obtain variables DSQ0101 – DSQ0104.

6) To exclude MEDs from the SAIDI and SAIFI calculations the MED threshold was calculated for the 2013 regulatory year in accordance with the STPIS guidelines[6]. This used the historical five year data for SAIDI (2008 - 2012) less exclusions (column [M] above) and was calculated at T_{MED} = 3.26 minutes.

7) Using T_{MED} each day was flagged as either a major event day or not. The same calculations for variables DSQ0101 – DSQ0104 were then performed on the data exclusive of major event day to obtain variables DSQ0105 – DSQ0108.

The example calculations can be seen in columns [O] to [V] below:

[6] Electricity distribution network service providers - Service target performance incentive scheme, November 2009 – Appendix D: Major Event Days

[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]
Tmed							
3.26				DQS0105	DQS0107	DQS0106	DQS0108
Ln All SAIDI Less Excl	MED	SAIDI MED	SAIFI MED	All SAIDI Less MED	All SAIFI Less MED	All SAIDI Less Excl Less MED	All SAIFI Less Excl Less MED
	NO	0	0	0.80106243	0.01959563	0.80106243	0.01959563
	NO	0	0	0.20931854	0.0023032	0.20931854	0.0023032
	NO	0	0	0.40130777	0.00701533	0.40130777	0.00701533

7.1.4 Estimates

An estimate of single loss outages was used in the calculation of all 2006 figures. This has been determined to be an immaterial portion of the 2006 figures and as such Energex is confident the 2006 figures are a good representation of the data.

7.1.4.1 Justification for estimates

The single loss estimate was required as actual single loss data was not collected or reported within the business prior to 2007.

7.1.4.2 Basis for estimates

All data for the period 2007 to 2013 includes a small component for single loss incidents (involving an interruption to one customer, typically the primary fuse blowing for residential customers). The contribution is typically less than one percent of the total and is not considered material to the reported figures in the template.

The total 2006 estimate for CML and CI are 2,000,000 and 10,000 respectively. This is consistent with an analysis of historical data for the period 2007 to 2013. This estimated value has been included in the overall figures reported for 2006 and represents around 0.8% of the SAIDI total and 0.2% of the SAIFI total.

Financial Year	Customer Minutes Lost Amount	Customers Affected Count	Outage Cause Id	STPIS Cause Exclude Indicator	Network Outage Planned Indicator	STPIS Outage Include Indicator
2007	1901644.967	10015	Null		NO	YES
2008	1695916.183	10427	Null		NO	YES
2009	1341196.267	10618	Null		NO	YES
2010	1037853.217	8854	Null		NO	YES
2011	1730925.15	9662	Null		NO	YES
2012	928289.3	8025	Null		NO	YES
2013	2988667.883	9770	Null		NO	YES

For consistency of the dataset, it is considered reasonable to include an estimate of the single loss contribution for 2006 based on the historical values for the period 2007 to 2013. Apart from 2013, there has generally been a downward trend over this period. It is considered reasonable to substitute the 2007 value with some rounding up to indicate that 2006 would likely have been higher than 2007.

7.1.5 Explanatory notes

Not Applicable

7.1.6 Accounting policies

Not Applicable

7.1.6.1 Nature of the change

Not Applicable

7.1.6.2 Impact of the change

Not Applicable

7.2 Energy not supplied

The AER requires Energex to provide the following variables relating to energy not supplied to customers:

- **DQS0201 - Energy Not Supplied (planned)**
- **DQS0202 - Energy Not Supplied (unplanned)**
- **DSQ02 – Energy Not Supplied - Total**

These variables are a part of worksheet 7 – Quality of Services.

All information is estimated.

7.2.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions	Demonstrated in section 7.2.3 (Methodology).
DNSP must estimate the raw (not normalized) energy not supplied due to unplanned customer interruptions based on average customer demand (multiplied by the number of customers interrupted and the duration of the interruption). Average customer demand must be determined from (in order of preference): • average consumption of the customers interrupted based on their billing history; • feeder demand at the time of the interruption divided by the number of customers on the feeder; • average consumption of customers on the feeder based on their billing history; • average feeder demand derived from feeder Maximum Demand and estimated load factor, divided by the number of customers on the feeder.	Demonstrated in section 7.2.3 (Methodology).
Energy not supplied should be reported exclusive of the effect of Excluded Outages as defined in chapter 9	Demonstrated in section 7.2.3 (Methodology).

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all variables are estimates.

7.2.2 Sources

Variable Code	Variable	Unit	Source
DQS0201	Energy Not Supplied (planned)	GWh	NFM
DQS0202	Energy Not Supplied (unplanned)	GWh	NFM
DSQ02	Energy Not Supplied – Total	GWh	NFM

7.2.3 Methodology

Energex calculated the energy not supplied to customers in a similar method to AER's preference number 3. However, the calculation has been done at a distribution transformer level, rather than at the suggested feeder level. In general, this lower level of granularity should provide more accurate results.

In extracting the outage data the outages exclude generation/transmission events and momentary interruptions but include major event days. This aligns to the AERs requirement of "*raw (not normalized) energy not supplied due to unplanned customer interruptions".*

Energex's calculation does not require customer numbers, as customer numbers in both the numerator (number of customers interrupted) and the denominator (number of customers on each distribution transformer) of the calculation essentially cancel out. The working showing the equivalence of this methodology can be seen below:

The methodology stated by the AER can be summarised as:

$$ENS = \sum_{i=1}^{n} Average\ Demand\ of\ Customers_i \times No.of\ Customers\ Interrupted_i \times Duration_i$$

Where i = an unplanned customer interruption, and n = the number of interruptions for the given regulatory year

As stated in point 3 of the AERs guidance above the average demand of customers interrupted can be estimated by the average demand of customers on the feeder. At a transformer level of granularity this is the average demand of customers on a distribution transformer which can be stated as such:

$$Average\ Demand\ of\ Customers_i = \frac{Average\ Transformer\ Demand_i}{No.of\ Customers\ Interrupted_i}$$

The Energy not Supplied equation then becomes:

$$ENS = \sum_{i=1}^{n} \frac{Average\ Transformer\ Demand_i}{No.of\ Customers\ Interrupted_i} \times No.of\ Customers\ Interrupted_{\ i} \times Duration_i$$

$$ENS = \sum_{i=1}^{n} Average\ Transformer\ Demand_i \times Duration_i$$

This is the final formula used by Energex to calculate the Energy not Supplied variable (please note that Energex also uses a figure for the % of the transformer interrupted to ensure accuracy of the supplied figures).

The details of the approach are set out below.

7.2.3.1 Assumptions

The following assumptions have been applied to estimating the required variables:

- Completely flat load curves apply, meaning that there no load variation for time, day, or month. The materiality of this assumption will be low as outages are relatively evenly spread over time in a 12 month period.
- Where energy consumption is not available for a specific transformer the average consumption of known transformers on the same feeder is used as the average transformer demand.
- Where feeder information can also not be determined the “system” average (i.e. total system energy consumption divided by total number of distribution transformers) is used as the average transformer demand.
- Where only part of transformer is interrupted (e.g. 33% or 66%) the average transformer demand is multiplied by the percentage interrupted.
- Annual energy consumption per distribution transformer data is not available before 2008/09. The 2008/09 distribution transformer energy data was used in the calculations for 2005/06, 2006/07 and 2007/08. However, the final energy not supplied figures for these years were then prorated using the ratio of the total system energy consumption in these years compared to 2008/09.
- Data was only available for the current numbers of transformers per feeder and as such all calculations were based on these figures.

7.2.3.2 Approach

1) The total energy consumed on each distribution transformer for each regulatory year and their corresponding feeders was collated based on customer billing data (ultimately sourced from PEACE).

The following data was also extracted from the Energex NFM system:

- The current number of distribution transformers on each feeder
- The details of each outage from 2006 – 2013 including the transformer, the duration and percentage of the transformer interrupted and whether the interruption was planned or unplanned.

2) Average transformer demand was calculated as the total energy consumption on a particular distribution transformer divided by 525 600 (number of minutes in a year) to obtain an average transformer demand.

3) The average transformer demand was then mapped to the outage data from 2006 – 2013. Where the average transformer demand was unable to be mapped to the outage data, the demand was stated as the average transformer demand of the other transformers on that feeder (11 kV feeder level). If both these sources of data were unavailable the system wide average of transformer demand was used.

4) The energy not supplied for a particular outage was then calculated as:

$$ENS_i = Average\ Transformer\ Demand_i \times Duration_i \\ \times \%\ of\ transformer\ interrupted_i$$

5) Each outage was then classified as planned or unplanned and summated to give an overall figures for energy not supplied (planned) and energy not supplied (unplanned) for each regulatory year.

6) The figures for planned and unplanned energy not supplied were then summated to give a total figure for energy not supplied for a given regulatory year.

7) Energy not supplied due to single loss of supply incidents was then added to the total unplanned unsupplied energy. This was calculated by determining an average customer demand for each year and multiplying it by the customer minutes lost for that year (as determined for the SAIDI and SAIFI Reliability variables and summarised in Basis of Preparation for Reliability). The average customer demand was calculated by dividing the total energy consumption by the total number of customers in each year.

7.2.4 Estimates

The values provided for all variables are estimates.

7.2.4.1 Justification for estimates

Energex does not measure the energy not supplied to customers directly and has estimated the figures based on the methodologies specified by the AER.

7.2.4.2 Basis for estimates

The estimated figures are based on the average transformer demand multiplied by the duration of the transformer outage and the percentage of transformer interrupted. For details and assumptions please see the methodology section above.

7.2.5 Explanatory notes

Not Applicable

7.2.6 Accounting policies

Not Applicable

7.2.6.1 Nature of the change

Not Applicable

7.2.6.2 Impact of the change

Not Applicable

7.3 System losses and capacity utilisation

The AER requires Energex to provide the following variables relating quality of service:

DQS03 – System losses

DQS04 – Overall capacity utilisation

These variables are a part of worksheet 7 – Quality of Service and are to be reported for regulatory years 2006 – 2013.

All values provided for variables DQS03 and DQS04 is actual information.

7.3.1 Consistency with EB RIN Requirements

The AER has specified the following requirements in relation to reporting system losses and capacity utilisation:

Requirements (instructions and definitions)	Consistency with requirements
System losses are the proportion of energy that is lost in distribution of electricity from the transmission network to Energex customers. Energex must report distribution losses calculated via the following equation: $$system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$$ This is a system wide figure inclusive of inflows from Embedded Generation and outflows to other DNSPs.	Energex has calculated system losses in line with the guidance provided by the AER. Refer to section 7.3.3 for details.
Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year. Energex must report the sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity. For the purpose of this measure, thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant). This must be the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity should similarly be the continuous rating.	Energex has calculated capacity utilisation in line with the guidance provided by the AER. Refer to section 7.3.3 for details.

7.3.2 Sources

Variable Code	Variable	Source
DQS03	System losses	Published Distribution Loss Factor (DLF) Repots, Metering systems, PEACE
DQS04	Overall capacity utilisation	SIFT (for ratings), SCADA (for load)

7.3.3 Methodology

Both variables were calculated using the methodology specified by the AER.

7.3.3.1 Assumptions

7.3.3.2 Approach

System Losses

System loss figures are reported by Energex in the DLF reports each year. The DLF reports are calculated in the same manner to that specified by the AER for the EB RIN.

Two figures are required for the calculation of system losses, the electricity imported into the system and the electricity delivered from the system. The system loss percentage is then calculated as the energy loss divided by the total energy imported into the system.

- Electricity imported into the Energex network was obtained from metering data at system input points and summated for each regulatory year.
- Electricity sold to customers and exported from the system was obtained from the Energex billing system (PEACE) and was summated for each regulatory year. The difference between these two figures was then calculated as the energy lost from the distribution system.
- The percentage system losses was then calculated using the following equation:

$$system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$$

Capacity Utilisation

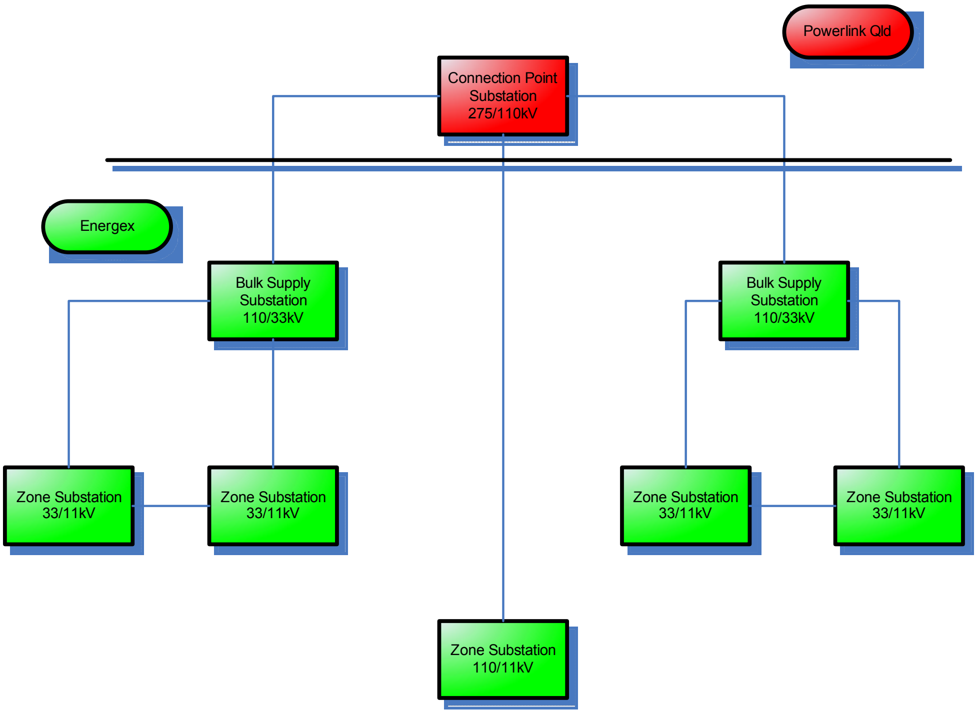
The network capacity utilisation is calculated as the percentage utilisation of zone sub-station thermal capacity. This is calculated using the total network non-coincident maximum demand divided by the total network zone sub-station thermal capacity as specified by the AER.

1) The total network non-coincident maximum demand was obtained from the Energex SCADA system and summated for each regulatory year.

2) The zone substation thermal capacity was extracted from the Energex SIFT and ERAT systems for each regulatory year. The thermal capacities included the nameplate capacities as well as any extra capacity added for cooling upgrades.

The calculation specified by the AER is not correct for estimating overall system utilisation. DPA0604 is a summation of the Energex bulk supply and zone substation capacities. The correct calculation should only include the final step of transformation (DPA0602 and DPA0603). If these values were used in the Utilisation calculation the final results would be:

DOPSD0201	4974	5053	5104	5467	5509	5296	5195	5190
DPA0602 + DPA0603	9453	10091	10206	10464	10648	10938	11190	11295
Capacity Utilisation	52.62%	50.07%	50.01%	52.24%	51.74%	48.42%	46.42%	45.95%



The diagram of the Energex supply network shows the zone substation load being supplied via bulk supply substations except in the case where direct transformation substations (110/11kV) are employed. DPA0601 is the 110/33kV bulk supply substation capacity to a meshed network supplying the 33/11kV zone substations.

7.3.4 Estimates

Not Applicable

7.3.4.1 Justification for estimates

7.3.4.2 Basis for estimates

7.3.5 Explanatory notes

Not Applicable

7.3.6 Accounting policies

Not Applicable

8 OPERATING ENVIRONMENT

8.1 Rural Proportion

The AER requires Energex to provide:

DOEF0201 – Rural proportion of line length

This is as a part of worksheet 8 – Operating Environment.

All variables are estimated information.

8.1.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Rural Proportion is Distribution line route length classified as short rural or long rural in km / total network Line Length	Demonstrated in section 8.1.3.2.
Total network Line Length is the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag	This definition of Line Length was applied
If Energex has Actual Information, Energex must report all years of available data. If Energex does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Energex does not have actual information therefore an estimate is provided for the most recent regulatory year

All variables have been provided in accordance with the AER’s instructions and definitions.

The values provided for all variables are actuals.

8.1.2 Sources

Variable Code	Variable	Source
DOEF0201	Rural proportion	ArcGIS

8.1.3 Methodology

All data to calculate the rural proportion variable was obtained through the Energex ArcGIS system. These figures were then used to calculate the proportion of rural overhead line length for each individual year. Rural proportion, expressed as a percentage, was then calculated by dividing total rural overhead line length, by route line length (which included underground circuit lengths in accordance with direction provided by the AER 9 April 2014).

8.1.3.1 Assumptions

The calculation of this variable assumed that:

- A rural area is defined by the level of demand on a network. The following ranges were used for the calculation of rural overhead line length:
  - Urban/CBD: >300 kVA/km
  - Rural: ≤300 kVA/km

8.1.3.2 Approach

1) A GIS “shapefile” was generated within the Energex ArcGIS system that defined the boundaries of where the network was considered “Rural” or “Urban”. This was built on the assumption that a rural area could be defined as having a network demand of less than 300 kVA/km.

2) The line length within the rural boundaries was then calculated by the GIS system to give a total rural proportion for each year.

8.1.4 Estimates

Estimates have been calculated for the underground portion of route line length.

8.1.4.1 Justification for estimates

It was necessary to estimate underground route line length using total underground circuit length.

8.1.4.2 Reasons for estimates

The AER (in an email dated 9 April 2014) directed that Energex include underground network in its calculation of route line length. To perform this calculation Energex had to use total underground circuit length values provided for DPA02.

8.1.5 Explanatory notes

Energex has only “short rural” line lengths.

Energex notes that the inclusion of the underground network in route line length has skewed the overall rural proportion. As noted in the Basis of Preparation for Route Line Length, Energex considers that the inclusion of underground network in vegetation management benchmarking is inappropriate given that work is drive by the overhead network. This material impacts the rural proportion as set out in the table below.

	2009	2010	2011	2012	2013
Including underground	41.95%	41.30%	40.78%	40.32%	39.95%
Excluding underground	65.85%	65.85%	65.85%	65.85%	65.85%

8.1.6 Accounting policies

Not Applicable

8.2 Maintenance spans and tree numbers

The AER requires Energex to provide:

- **DOEF0202 – Urban and CBD vegetation maintenance spans**
- **DOEF0203 – Rural vegetation maintenance spans**
- **DOEF0204 – Total vegetation maintenance spans**
- **DOEF0208 – Average number of trees per urban and CBD vegetation maintenance span**
- **DOEF0209 – Average number of trees per rural vegetation maintenance span**

These variables are a part of worksheet 8 – Operating Environment.

All figures stated for these variables are estimates based on statistical sampling.

8.2.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
A vegetation maintenance span 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 8.2.3.2.
If Energex has Actual Information, Energex must report all years of available data. If Energex does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Energex does not have actual information therefore an estimate is provided for the most recent regulatory year

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all variables are estimates.

8.2.2 Sources

Variable Code	Variable	Unit	Source
DOEF0202	Urban and CBD vegetation maintenance spans	Number of spans	Field Surveys
DOEF0203	Rural vegetation maintenance spans	Number of spans	Field Surveys
DOEF0204	Total vegetation maintenance spans	Number of spans	Field Surveys
DOEF0208	Average number of trees per urban and CBD vegetation maintenance span	Trees	Field Surveys
DOEF0209	Average number of trees per rural vegetation maintenance span	Trees	Field Surveys

8.2.3 Methodology

Energex has estimated both the number of vegetation managements spans and the average number of trees per maintenance span using a statistical sampling methodology. This was performed for both Urban/CBD and Rural areas to obtain the variable figures.

8.2.3.1 Assumptions

The following assumptions underpin the values provided:

- 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 when sampling the number of trees per maintenance span were trees within that span that require active maintenance or could be reasonably seen to require active maintenance in the future.
- Sampling of network spans to identify the portion of maintenance spans was undertaken on the distribution network, and it was assumed that the portion of maintenance spans on the distribution network is the same as that for the subtransmission network.

8.2.3.2 Approach

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. The variable "DOEF0204 – Total Vegetation Maintenance Spans" was then calculated as the sum of the Urban/CBD and Rural variables.

Obtaining span sample:

1) 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 8.2.3.1 above. This shapefile was then used to calculate the total population sizes of Urban/CBD and Rural spans in Energex's distribution network i.e. 33 kV and below (the spans of Energex's subtransmission network were not included in sample populations).

2) 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 (1984 spans for both Urban/CBD and Rural) were deliberately higher than the minimum calculated to ensure statistical relevance of the sampling.

3) 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.

4) A pole with ID of nnnn (where n = 1 → ∞) was taken. The pole ID number was generated from http://www.randomizer.org/ 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.

5) 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 required active maintenance or could be reasonably seen to require active maintenance in the future were counted.

Calculation of variables:

1) 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.

2) The total number of maintenance spans was calculated as the addition of urban/CBD and rural maintenance spans.

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

8.2.4 Estimates

All data for variables DOEF0202, DOEF0203, DOEF0204, DOEF0208 and DOEF0209 are considered estimates and have only been provided for the most recent regulatory year.

8.2.4.1 Justification for estimates

Energex did not have actual data available for these variables therefore data was estimated for the most recent regulatory year only.

8.2.4.2 Methodology 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.

8.2.5 Explanatory notes

Not Applicable

8.2.6 Accounting policies

Not Applicable

8.2.6.1 Nature of the change

Not Applicable

8.2.6.2 Impact of the change

Not Applicable

8.3 Span numbers and tropical and bushfire risk

The AER requires Energex to provide:

- **DOEF0205 – Total number of spans**
- **DOEF0212 – Tropical proportion**
- **DOEF0214 – Bushfire risk**

These variables are a part of worksheet 8 – Operating Environment and were obtained from the Energex Geographical Information System.

Data provided for DOEF0205 is actual information.

Data provided for DOEF0212 and DOEF0214 is estimated information.

8.3.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
If DNSP records poles rather than spans, the number of spans is the number of poles less one	Energex records spans.
The tropical proportion is the approximate total number of urban and Rural Maintenance Spans in the Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity).	Demonstrated in section 8.3.3.2.
The bushfire risk variable is the number of Maintenance Spans in high bushfire risk areas as classified by a person or organisation with appropriate expertise on fire risk. This includes but is not limited to: - DNSP's jurisdictional fire authority - local councils - insurance companies - DNSP's consultants - Local fire experts	Demonstrated in section 8.3.3.2.

Requirements (instructions and definitions)	Consistency with requirements
If DNSP has Actual Information, DNSP must report all years of available data. If DNSP does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Historical actual information was not available for both the "tropical portion" and "bushfire risk" variables and as such these have been estimated for 2013 only.

All variables have been provided in accordance with the AER's instructions and definitions.

Data provided for DOEF0205 is actual information whilst data provided for DOEF0212 and DOEF0214 is estimated information.

8.3.2 Sources

Variable Code	Variable	Source
DOEF0205	Total number of spans	ArcGIS
DOEF0212	Tropical proportion	ArcGIS/ BOM
DOEF0214	Bushfire risk	ArcGIS/ Queensland Government

8.3.3 Methodology

Energex has calculated the total number of overhead spans, the tropical proportion spans and the bushfire risk spans using ArcGIS. This incorporated shapefiles from the Bureau of Meteorology and the Queensland Government to obtain the number of spans within tropical and bushfire risk areas.

8.3.3.1 Assumptions

Not applicable

8.3.3.2 Approach

1) The total number of overhead spans was obtained by extracting the figures directly from ArcGIS. This was extracted for the years 2009-2013.

2) The tropical proportion variable was calculated by overlaying the Australian Bureau of Meteorology Australian Climatic Zones GIS shapefile[7] on the Energex maps. From here the total number of overhead spans that fell within the tropical regions was calculated by the GIS system. This figure was then multiplied by the total proportion of maintenance spans to non-maintenance spans from the calculated variables DOEF0204 and DOEF0205 to give the number of maintenance spans in a tropical area.

3) The bushfire risk variable was calculated by overlaying the Queensland Government Department of State Development, Infrastructure and Planning Bushfire Risk GIS shapefile[8] on the Energex maps. From here the number of overhead spans that fell within the bushfire risk regions was counted by the GIS system. This figure was then multiplied by the total proportion of maintenance spans to non-maintenance spans from the calculated variables DOEF0204 and DOEF0205 to give the number of maintenance spans in a bushfire risk area.

8.3.4 Estimates

All data provided for variables "DOEF0212 – Tropical Proportion" and "DOEF0214 – Bushfire Risk" are estimates.

8.3.4.1 Justification for estimates

The two variables of "DOEF0212 – Tropical Proportion" and "DOEF0214 – Bushfire Risk" are estimates as they rely on the figure for "DOEF0204 – Total vegetation maintenance spans" which was estimated.

8.3.4.2 Methodology for estimates

The figure for DOEF0204 was estimated using a statistical sampling methodology outlined in Basis of Preparation 8-2. Estimates were calculated by multiplying the actual figures for total number of spans in a tropical or bushfire risk areas by the statistically calculated proportion of total maintenance spans to total spans.

Underground network was not included in these calculations as the instructions specifically seek span numbers. Further, bushfire risk and tropical portion were not deemed relevant to the underground network.

8.3.5 Explanatory notes

Not Applicable

8.3.6 Accounting policies

Not Applicable

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[7] http://www.bom.gov.au/climate/averages/climatology/gridded-data-info/gridded-climate-data.shtml
[8] http://www.dsdip.qld.gov.au/about-planning/spp-mapping-online-system.html

8.4 Maintenance cycles

The AER requires Energex to provide:

DOEF0206 – Average urban and CBD vegetation maintenance span cycle

DOEF0207 – Average rural vegetation maintenance span cycle

These variables are a part of worksheet 8 – Operating Environment.

Figures stated for 2009 – 2012 are estimates.

Figures stated for 2013 are actual information.

8.4.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Maintenance span cycle is the planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed for the relevant area	Demonstrated in section 8.4.3.
If there is no available data for the 'average vegetation Maintenance Span Cycle' Variables (DOEF0206 and DOEF0207), Energex is nevertheless required to estimate five years of back cast data. The average vegetation Maintenance Span Cycle can be calculated based on a simple average of all the Maintenance Span Cycles	Demonstrated in section 8.4.4.1.
Maintenance Span Cycle is the planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed for the relevant area.	Application of this definition discussed in section 8.4.3.2
CBD and Urban Maintenance Spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant year. CBD and urban areas are consistent with CBD and urban customer classifications.	Demonstrated in section 8.4.3.1. and section 8.4.3.2
Rural Maintenance Spans are spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders. Rural areas must be consistent with rural short and rural long feeders.	Demonstrated in section 8.4.3.1. and section 8.4.3.2

All variables have been provided in accordance with the AER's instructions and definitions.

Values provided for 2009 – 2012 are estimates whilst values provided for 2013 are actual information.

8.4.2 Sources

Variable Code	Variable	Source
DOEF0206	Average urban and CBD vegetation maintenance span cycle	ArcGIS/vegetation management contracts
DOEF0207	Average rural vegetation maintenance span cycle	ArcGIS/vegetation management contracts

8.4.3 Methodology

Energex provided the DOEF0206 and DOEF0207 values using a weighted average of the Maintenance Span Cycles within urban/CBD and rural areas. The variable values were based on the current and historical vegetation management contracts which stipulated the cycle lengths. The figures for 2009 – 2012 have been estimated using the 2013 percentage split between Urban/CBD and Rural spans and the historical contract cycle lengths. Further detail is provided below.

8.4.3.1 Assumptions

A rural area is defined by the level of demand on a network. Consistent with CBD and urban customer classifications, the following ranges were used to define a rural span:

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

8.4.3.2 Approach

Energex uses three separate maintenance span cycles in their vegetation management contracts:

- 1 year – Urban areas
- 2 years – Rural areas
- 4 years – Rural areas

However the urban and rural classifications stated in these contracts are vegetation management classifications rather than feeder categories and could not be directly used. Therefore, the average maintenance span cycle for each required category was calculated using ArcGIS.

To calculate the average maintenance span cycles the relevant cycle was firstly attached to each maintenance span. These maintenance spans were then classified as Urban/CBD or Rural using the ArcGIS shapefile developed for DOEF0201 – Rural proportion. The average maintenance span cycle was then calculated for Urban/CBD and Rural.

8.4.4 Estimates

Values for the average rural vegetation maintenance span cycle from 2009–12 are estimates because these are based on maintenance spans, which are estimates (as discussed in the relevant Basis of Preparation). It is noted that input data relating to cycles and the proportion of urban and rural feeders is actual information.

8.4.4.1 Justification for estimates

Estimated values were provided for years 2009–12 as there was no historical data for the split between the spans on a two and four year rural cycle.

8.4.4.2 Basis for estimates

Due to minimal changes in the maintenance spans on a two or four year vegetation management cycle, the averages calculated for the 2013 regulatory year were considered to reflect the average maintenance span cycle for years 2009–12.

8.4.5 Explanatory notes

Not Applicable

8.4.6 Accounting policies

Not Applicable

8.5 Defects

The AER requires Energex to provide:

- **DOEF0210 – Average number of defects per urban and CBD vegetation maintenance span**
- **DOEF0211 - Average number of defects per rural vegetation maintenance span**

These variables are a part of worksheet 8 – Operating Environment.

All values provided for these variables are estimates.

8.5.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
DNSP must report the average number of vegetation related Defects that are recorded per Maintenance Span in the relevant year.	Demonstrated in section 8.5.3.2.
A Defect is any recorded incidence of noncompliance with a NSP's vegetation clearance standard. This also includes vegetation outside a NSP's standard clearance zone that is recognised as hazardous vegetation and which would normally be reported as requiring management under the NSPs Inspection practices.	Demonstrated in section 8.5.3.2.
In its basis of preparation, Energex must specify whether it records the total number of Defects for each vegetation Maintenance Span, or whether it records Defects on a vegetation Maintenance Span as one, regardless of the number of Defects on the span.	Energex does not record defects on either basis. Further discussion of this is provided in section 8.5.3.2.
If DNSP has Actual Information, DNSP must report all years of available data. If DNSP does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Energex does not have actual information prior to 2011 therefore estimates are provided for the three most recent regulatory years

Requirements (instructions and definitions)	Consistency with requirements
CBD and Urban Maintenance Spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant year. CBD and urban areas are consistent with CBD and urban customer classifications.	Demonstrated in section 8.5.3.1.
Rural Maintenance Spans are spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders. Rural areas must be consistent with rural short and rural long feeders.	Demonstrated in section 8.5.3.1.

All variables have been provided in accordance with the AER's instructions and definitions.

The values provided for all variables are estimates.

8.5.2 Sources

Variable Code	Variable	Source
DOEF0210	Average number of defects per urban and CBD vegetation maintenance span	Contract records
DOEF0211	Average number of defects per rural vegetation maintenance span	Contract records

8.5.3 Methodology

Energex has provided actual information for the average number of defects per maintenance span for both urban/CBD and rural areas. This was calculated as the actual number of defects recorded in the system, divided by the calculated number of maintenance spans. It is noted that defects reporting is unable to distinguish between urban and rural.

8.5.3.1 Assumptions

The following assumptions were applied:

- 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

- There is no statistical difference between the averages of urban/CBD and rural defects per maintenance span and thus the overall average of defects per maintenance span is a valid representation of both populations.

8.5.3.2 Approach

The data for the number of defects was gathered from records of non-compliance on field services contract invoices. These invoices indicate the number of non-conformances issued to the contractors based upon audits by Energex contract officers.

Importantly, Energex records the number of defects on a vegetation management span as one defect per vegetation management area. The Energex vegetation management policy states that, upon audit, only that a minimum number of defects need be recorded in an area for it to be classed as non-compliant. From here the contractor responsible for the site is ordered to rework the area and a single “defect” is recorded.

These defect numbers were then divided by the previously calculated number of vegetation maintenance spans (for details of calculation refer to the basis of preparation for variables DOEF0202-4) to obtain an average number of defects per maintenance span.

8.5.4 Estimates

Whilst the number of defects recorded by Energex is actual information, values provided are ultimately estimates because these are provided on the basis of maintenance span which is estimated on the basis of statistical sampling (discussed in the relevant Basis of Preparation)

8.5.4.1 Justification for estimates

These values are considered estimates due to the reliance on estimated values for maintenance span from DOEF0202-4.

8.5.4.2 Basis for estimates

Refer to the basis of preparation for DOEF0202, DOEF0203 and DOEF0204 for the methodology used to obtain estimates for maintenance spans.

8.5.5 Explanatory notes

Not Applicable

8.5.6 Accounting policies

Not Applicable

8.6 Standard vehicle access

This Basis of Preparation relates to the following variable:

- **DOEF0213 – Standard vehicle access**

This variable is a part of worksheet 8 – Operating Environment and was provided, as an estimate for the 2013 year only. Actual data on this variable is not held by Energex, therefore data is not provided for years for years 2009-12.

8.6.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Standard vehicle access is "Distribution route Line Length that does not have Standard Vehicle Access. Areas with Standard Vehicle Access are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks). An area with no Standard Vehicle Access would not be accessible by a two wheel drive vehicle."	Energex does not have data regarding line length serviced through the areas specified; or that cannot be accessed by a two wheel drive vehicle. It has therefore used line length on road reserve as a proxy.
Route line length is "the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag."	Route line length is based on GIS system distance and does not include vertical components
"If DNSP has Actual Information, DNSP must report all years of available data. If DNSP does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year."	In the absence of actual data Energex has estimated data for standard vehicle access for the most recent regulatory year using the Energex GIS as the distribution route line length that falls within the road reserve.

8.6.2 Sources

Variable Code	Variable	Unit	Source
DOEF0213	Standard vehicle access	km	ArcGIS

8.6.3 Methodology

The distribution route line length with standard vehicle access was estimated by identifying the line length that falls within the known road reserve boundaries. This was subtracted from total route line length to find the distribution route Line Length that does not have Standard Vehicle Access.

8.6.3.1 Assumptions

It is assumed that the route line length that falls within road reserve boundaries is an appropriate proxy for standard vehicle access, as this line can typically be access by standard vehicles.

8.6.3.2 Approach

The distribution route line length with standard vehicle access was estimated by identifying the line length that falls within the known road reserve boundaries. This was calculated within ArcGIS by overlaying the distribution line segments with the known road reserve boundaries and counting the line segments within those boundaries.

8.6.4 Estimates

The figure stated for the standard vehicle access variable is an estimate, given that it is contingent on judgments and assumptions, and has been provided for the 2013 year only.

8.6.4.1 Justification for estimates

This variable was estimated as Energex does not measure the distribution route line length with standard vehicle access.

8.6.4.2 Basis for estimates

As stated in the methodology section, the estimate for this variable was based on calculating the route line length that falls within the known road reserve boundaries. This was considered the most representative figure Energex could produce based on the available information.

There are two opposing situations that may affect the accuracy of this estimate:

1. Line length may be accessible by a standard vehicle but is not on a road reserve (e.g. across open paddocks off the road reserve); and
2. Line length may be within a road reserve but may not be accessible by a standard vehicle (e.g. line that falls in a section of undeveloped road reserve)

Given the lack of data held by Energex systems the effects of each these situations on the estimate are unknown, and may or may not have a balancing effect on the figure reported.

8.6.5 Explanatory notes

Not Applicable

8.6.6 Accounting policies

Not Applicable

8.7 Route Line length and customer density

This Basis of Preparation relates to the following variables:

- **DOEF0301 – Route Line length (RIN Table 8.3)**
- **DOEF0101 Customer density (RIN Table 8.1)**

These variables are a part of worksheet 8 – Operating Environment.

For DOEF0301 values are estimated information.

For DOEF0101 the values provided are estimates, given that customer number information is estimates.

8.7.1 Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which this Basis of Preparation is consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex must input the route Line Length of lines for DNSP's network.	Demonstrated in section 8.7.3.2.
Line Length is based on the distance between line segments and does not include vertical components such as line sag. The route Line Length does not necessarily equate to the circuit length as the circuit length may include multiple circuits.	Demonstrated in section 8.7.3.1.
Actual figures must be provided for years 2006-2013 and if data is unavailable the figures must be estimated.	Demonstrated in sections 8.7.3 and 8.7.4.
Customer density is the total number of customers divided by the route Line Length of the network.	Demonstrated in section 8.7.3.2.

All variables have been provided in accordance with the AER's instructions and definitions.

For DOEF0301 values provided for 2006 and 2008-13 are actual information. The value provided for 2007 is estimated information. For DOEF0101 the values provided are estimated, given that customer number information is estimates.

8.7.2 Sources

Variable Code	Variable	Source
DOEF0301	Route Line length	ArcGIS

8.7.3 Methodology

Energex has extracted actual figures for the distribution route line length for years 2008 – 2013 from ArcGIS.

8.7.3.1 Assumptions

Route line length includes only horizontal components of line length.

Route line length does not take into account multiple circuits within a line segment.

Total underground circuit length, which is the aggregate of each circuit length provided at each voltage level (variables DPA0201 to DPA0206), does not include multiple circuits with each segment.

8.7.3.2 Approach

Route line length was calculated within the ArcGIS software as the aggregate point to point distance of overhead line segments; plus the total underground circuit length (variable DPA02) for the relevant year.

This approach effectively excludes vertical components of line length and does not take into account multiple circuits on the overhead network.

To calculate customer density (DOEFO101), total customer number (DOPCN01, calculated in accordance with the Customer Numbers Basis of Preparation) for each year was divided by route line length.

8.7.4 Estimates

8.7.4.1 Justification for estimates

Due to a lack of data before in 2007 the figure for 2007 was estimated.

Customer number information is derived from estimates therefore customer density is an estimate.

8.7.4.2 Methodology for estimates

The value for 2007 was estimated by interpolating the 2008–13 data.

The Basis of Preparation for customer numbers describes the methodology that underpins estimates.

8.7.5 Explanatory notes

Energex considers that the inclusion of its underground network in the measurement of route line length is inappropriate in respect of its vegetation management program as this is driven entirely by the overhead network. The inclusion of the underground network materially overstates the network subject to vegetation management as illustrated in the table below.

	2006	2007	2008	2009	2010	2011	2012	2013
Including underground	37863	38739	39599	40484	41131	41689	42178	42587
Excluding underground	25662	25717	25772	25788	25794	25818	25828	25839

8.7.6 Accounting policies

Not Applicable.