Energex

Economic Benchmarking RIN

Basis of Preparation

2013-2014

energex

positive energy

Version control

Version	Date	Description
Version 1.0	23/10/2014	First Response 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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3.1 REVENUE

Revenue – Standard Control Services

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

3.1.1. 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

3.1.2 Revenue grouping by Customer type or class

- DREV0201 – Revenue from residential Customers
- DREV0202 – Revenue from non-residential customers not on demand tariffs
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- 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

3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes

- DREV0301 – EBSS
- DREV0302 – STPIS
- DREV0303 – F-Factor
- DREV0304 – S.Factor True up
- DREV0305 – Other
- DREV03 - Total revenue of incentive schemes

These variables are a part of Regulatory Template 3.1 – Revenue.

All total revenue in each table and figures reported for 2014 is Actual Information.

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 3.1.1) and by customer class (RIN Table 3.1.2).	SCS revenue figures have been reported in line with the AERs requirements. Demonstrated in the methodology section.
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 the methodology section.
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	Not applicable as no revenues reported.
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 3.1.3).	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"
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.

Sources

RIN Table 3.1.1 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
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 3.1.2 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
DREV0206	Revenue from Other Customers	$'000	PEACE/Regulatory Accounts
DREV02	Total revenue by customer class	$'000	PEACE/Regulatory Accounts

RIN Table 3.1.3 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	F-Factor		N/A
DREV0304	S-Factor True up		N/A
DREV0305	Other		
DREV03	Total revenue of incentive schemes	$'000	PEACE/Regulatory Accounts

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 the revenue figures.

Assumptions

The following assumptions were applied:

- All network tariff codes (NTCs) are assumed to be 100% attributable to each applicable line item;
- 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 Regulatory Template and have been included in the Opex Regulatory Template.

Approach

1) The following reports have been used for Regulatory Year 2014:

   - 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 3.1.1 – Revenue by chargeable quantity”; and the network tariff code informs “RIN Table 3.1.2 – Revenue by customer type”.

3) For RIN Table 3.1.1 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)
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) 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:

- For 2014, all unmetered supplies (being public lighting, watchman lights and other unmetered supplies) were billed in a similar manner. An additional Peace report was requested which breaks down the unmetered supplies into these three areas. This allowed Unmetered Supplies (DREV0107) and Revenue from Public Lighting (DREV0112) to have the correct allocation of unmeter supplies rather than it being apportioned as it was last year in Table 2.1. This does not affect RIN Table 3.1.2 as both line items from RIN Table 3.1.1 are already aggregated into Revenue from Unmetered Supplies (DREV0205).
- For 2014 there was a reconciliation difference to the Regulatory Accounts of -$121,560.80 as this equated to less than 1% due to the materiality level it was decided that this would be smoothed over all the Revenue Categories with the exception of DREV0113 and DREV0206.

Estimated Information

All data for 2014 is Actual Information.

Justification for Estimated Information

N/A

Basis for Estimated Information

N/A

Explanatory notes

Revenue from public lighting can be seen to increase substantially from 2013 to 2014. This is due to the unmetered supplies being able to be accurately broken down into unmetered and public streetlighting as opposed to 2013 just being based on proportions of prior years.

Revenue from unmetered supplies can be seen to slightly decrease from 2013 to 2014. This is due to the unmetered supplies being able to be accurately broken down into unmetered and public streetlighting as opposed to 2013 just being based on proportions of prior years.

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.

Revenue – Alternative Control Services

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

3.1.1. 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**

3.1.2 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**

3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes

- **DREV0301 – EBSS**
- **DREV0302 – STPIS**
- **DREV0303 – F-FActor**
- **DREV0304 – S-Factor True up**
- **DREV0305 – Other**
- **DREV03 - Total revenue of incentive schemes**

These figures are a part of Regulatory Template 3.1 – Revenue.

All figures reported for ACS revenue are Actual Information.

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 3.1.1) and by customer class (RIN Table 3.1.2).	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 Approach
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	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 3.1.3).	Figures for ACS revenue have been generated from the Regulatory Accounts for 2014.
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"
ACS are defined in the NER. By way of context, ACS 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 ACS are for DNSPs located in Queensland, excluded distribution services as determined by the Queensland Competition Authority	ACS has been reported for the year 2014.

Sources

RIN Table 3.1.1 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
DREV0112	Revenue from public lighting charges	$'000	Regulatory Accounts/ Income Statements
DREV0113	Revenue from other Sources	$'000	Regulatory Accounts/ Income Statements
DREV01	Total revenue by chargeable quantity	$'000	Regulatory Accounts

RIN Table 3.1.2 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 Statements
DREV0206	Revenue from Other Customers	$'000	Regulatory Accounts / PEACE reports/ Income Statements
DREV02	Total revenue by customer class	$'000	Regulatory Accounts

RIN Table 3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes			
Variable Code	**Variable**	**Unit**	**Source**
DREV0301	EBSS	$'000	Not Applicable
DREV0302	STPIS	$'000	Not Applicable
DREV0303	S-Factor	$'000	Not Applicable
DREV0304	S-Factor True up	$'000	Not Applicable
DREV0305	Other	$'000	Not Applicable
DREV03	Total revenue of incentive schemes	$'000	Not Applicable

Methodology

Figures for ACS revenue have been generated from the Regulatory Accounts for 2014.

Assumptions

N/A

Approach

All figures are based on the Regulatory Accounts submitted to the AER. Data was obtained from the annual RIN submitted. The reported ACS revenue figures and their method of calculation from the source documentation is provided in the table below.

Variable Code	Variable Description	Construction Methodology
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
DREV0110	Revenue from metering charges	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 • Special Meter Reads • Meter Investigation • It also included all Fee Based capital contributions revenue as these are related to metering charges.
DREV0112	Revenue from public lighting charges	The figure is inclusive of street lighting fixed charges. It also included all Street Lighting capital contributions revenue.
DREV0113	Revenue from other Sources	Calculated as the total for Quoted Services Revenue. 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 and therefore no revenue or penalties have been reported.

Accounting policies

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

3.2 OPERATING EXPENDITURE

3.2 OPERATING EXPENDITURE

As per the AER (Australian Energy Regulator) requirements, Energex is providing the following variables relating to Opex for Standard Control Services (SCS) and Alternative Control Services (ACS):

Table 3.2.1 Opex Categories

- **Table 3.2.1.1 Current opex categories and cost allocations**
  - **DOPEX0101-13 – Individual opex categories per annual Regulatory Accounting Statements**
  - **DOPEX01 – Total opex**
- **Table 3.2.1.2A Historical opex categories and cost allocations**
  - **DOPEX0101-13A – Individual opex categories per annual Regulatory Accounting Statements**
  - **DOPEX01A – Total opex**

Table 3.2.2 Opex consistency

- **Table 3.2.2.1 Opex consistency – current cost allocation approach**
  - **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**
- **Table 3.2.2.2 Opex consistency – historical current cost allocation approach**
  - **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**

These variables are a part of worksheet 3.2 Opex and are reported for regulatory year 2014.

Note that the Economic Benchmarking Regulatory Information Notice (EB RIN) template that was issued together with the EB RIN in November 2013 has been changed for 2014. In the

new EB RIN template, Opex is now in worksheet 3.2 instead of 3. The EB RIN itself including Instructions and Definitions has not changed. Therefore the table references in the AER requirements section in this basis of preparation (per the EB RIN) are different to the actual table references, which are per the new template for 2014.

All data is actual information.

Consistency with EB RIN Requirements

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

AER Requirements (refer Appendix B of the EB RIN: Economic Benchmarking Data Template Instructions and Definitions)	Consistency with AER Requirements
Energex must report Opex in accordance with the categories that they reported in response to their Annual Reporting Requirements.	Table 3.1.1 and 3.1.2 are now tables 3.2.1.1 and 3.2.1.2 Energex has reported Opex in accordance with the categories reported in response to the Annual Reporting Requirements of the relevant years as detailed in tables 3.2.1.1 and 3.2.1.2A.
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.	As this Basis of Preparation is for 2014 (one year only), Opex in table 3.2.1.1 Current Opex categories and cost allocations is the same as Opex in table 3.2.1.2A Historical Opex categories and cost allocations. Energex has reported Opex in accordance with the categories reported in response to the Annual Reporting Requirements in the Final Regulatory Information Notice for 2012/13, 2013/14 and 2014/15 issued on 28 September 2012 and re-issued by the AER on 6 August 2014.
Opex in 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.	Table 3.1.1 is now table 3.2.1.1 The Opex amounts in table 3.2.1.1 have been prepared in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements for 2014. Total Opex equals that reported in the 2014 Regulatory Accounting Statements.
Energex must report its historical Opex categories in 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	Table 3.1.2 is now table 3.2.1.2 Energex has reported its historical Opex categories in accordance with the Opex within the Annual Reporting Requirements that

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.	applied in 2014. The Opex amounts reported in table 3.2.1.2A equal Opex line items reported in the 2014 Regulatory Accounting Statements.
For 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.	Table 3.2.1 is now table 3.2.2.1 Energex has reported Opex in the categories as defined in the AER EB RIN in accordance with its current Cost Allocation Approach. Total Opex for SCS in this table aligns with that in the 2014 Regulatory Accounting Statements.
For 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.	Table 3.2.2 is now table 3.2.2.2 Energex has reported Opex in the categories as defined in the AER EB RIN in accordance with its current Cost Allocation Approach. Total Opex for SCS in this table aligns with that in the 2014 Regulatory Accounting Statements.

Sources

Table 3.2.1 Opex categories			
Variable Code	**Variable**	**Unit**	**Source**
3.2.1.1 Current opex categories and cost allocations			
DOPEX0101-13	Individual opex categories	$'000	Annual Regulatory Accounting Statements
DOPEX01	Total opex	$'000	Annual Regulatory Accounting Statements
3.2.1.2A Historical opex categories and cost allocations			
DOPEX0101-13A	Individual opex categories	$'000	Annual Regulatory Accounting Statements
DOPEX01A	Total opex	$'000	Annual Regulatory Accounting Statements

Table 3.2.2 Opex consistency			
Variable Code	**Variable**	**Unit**	**Source**
3.2.2.1 Opex consistency - current cost allocation approach			
DOPEX0201	Opex for network services	$'000	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0202	Opex for metering	$'000	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0203	Opex for connection services	$'000	N/A
DOPEX0204	Opex for public lighting	$'000	Annual Regulatory Accounting Statements
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
3.2.2.2 Opex consistency - historical cost allocation approach			
DOPEX0201A	Opex for network services	$'000	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0202A	Opex for metering	$'000	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0203A	Opex for connection services	$'000	N/A
DOPEX0204A	Opex for public lighting	$'000	Annual Regulatory Accounting Statements
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

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.

Assumptions

N/A

Approach

Table 3.2.1.1 Current opex categories and cost allocations and table 3.2.1.2 Historical opex categories and cost allocations

Table 3.2.1.1 requires Opex be stated on the basis of the current Cost Allocation Approach. Table 3.2.1.2 requires Opex be stated on the basis of the Cost Allocation Method (CAM) used in the applicable regulatory year. As the current CoS (Classification of Services) and CAM have been applied from the 2011 regulatory year, the amounts stated for 2014 for both tables 3.2.1.1 and 3.2.1.2 are the same and have been taken directly from the 2014 Regulatory Accounting Statements.

Opex consistency – current cost allocation approach

The Opex consistency table based on the current CAM (table 3.2.2.1) has been based on the values stated in table 3.2.1.1 Current opex categories and cost allocations.

Table 3.2.1.1 balances to table 3.2.2.1 for SCS only. ACS will not balance between the two tables as table 3.2.2.1 does not require the ACS Opex categories reported against DOPEX0113 from table 3.2.1.1.

DOPEX0201 – Opex for network services

Network services are defined in the EB RIN Instructions and Definitions 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 value for "DOPEX0201 – Opex for network services" has been calculated as the total Opex value stated in 3.2.1.1 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 amounts in table 3.2.1.1 for two reasons. Firstly, the variable for "Meter reading and network billing" included network billing expenditure which was required to be removed in accordance with the definition of Metering. 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 Opex for Metering amount. The formula used for calculating Opex for Metering was therefore:

$$Opex\ for\ Metering = Metering\ Dynamics + Meter\ Reading\ and\ Network\ Billing - Network\ Billing\ Costs + O\&M\ Costs\ of\ Metering$$

The network billing component is identified by the specific responsibility centre coding for network billing activities.

The metering O&M costs for 2014 were extracted from project ledger information in Ellipse.

Once all amounts were obtained for network billing and metering O&M costs, Opex for Metering was calculated using the formula above.

DOPEX0203 – Opex for connection services

The amount for "DOPEX0203 – Opex for connection services" is zero as Energex classifies all connection expenditure as Capex.

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

The amount for "DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP" is 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 therefore the amount for this variable is zero.

Opex consistency – historical cost allocation approaches

As the current CoS and CAM have been applied from the 2011 regulatory year, amounts in table 3.2.2.2 are the same for those stated in table 3.2.2.1.

Estimates

There is no estimated information for this template.

Explanatory notes

Current opex categories and cost allocations

The following explanations are provided in relation to table 3.2.1.1 Current opex categories and cost allocations:

- Other network maintenance costs (DOPEX0106) represent maintenance costs for street lights.
- From 2011, SCS Other operating costs (DOPEX0113) includes solar photovoltaic (PV) feed in tariff (FiT) payments. For transparency, solar PV FiT payments were:
  - 2011 $19.4M
  - 2012 $73.9M
  - 2013 $167.1M
  - 2014 $227.5M

The following explanations are provided for the major variances between 2014 and 2013:

- DOPEX0101 Inspection costs have increased by 55% ($8.0M) due to lower than usual inspection costs for 2013. In order to comply with the Australian accounting standards and the Electrical Safety Regulations, a provision was raised in 2012 for inspection costs following the identification of a manufacturing fault on certain overhead service lines (Mitti cable) which had led to the premature deterioration of these cables. A revised estimate to complete the inspection program resulted in a partial reversal of the provision in 2013.
- DOPEX0105 Emergency response/storms costs have reduced significantly ($18.1M, 76%) as the costs in 2013 were higher than usual driven by network repair and restoration associated with various weather events, in particular ex-Tropical Cyclone Oswald and two other major event days.
- DOPEX0107 Network operating costs increase of $5.2M (21%) was due to the implementation of the Distribution Management System (which provides real-time information on power flow, network status, outages and network changes). Also the 2013 results were impacted by an understatement in overtime.
- DOPEX0108 Meter reading and network billing costs are down by $3.6M (21%) compared to 2013, primarily due to cost efficiencies gained and a reduction in contractor costs.
- DOPEX0109 Customer services (incl. call centres) costs have increased compared to 2013 ($5.4M, 30%) due to costs associated with the overhead service line inspections. This work was originally provided for as part of the overhead service line provision (with the corresponding increase to DOPEX0101 Inspection in 2012), however when the work is performed it is incurred as a Customer Service expense.

The remaining expense in 2014 was greater than the remaining balance in the provision, resulting in an increase to Customer Services costs.

- DOPEX0110 DSM (Demand Side Management) initiatives costs have reduced ($4.3M, 27%) due to completion of three programs in 2013 including Summer Preparedness.

Accounting policies

The Group changed its accounting policy in 2014 with respect to the basis for determining the cost related to its defined benefit fund.

Nature of the change

The change is as a result of revisions to Accounting Standard AASB 119 *Employee Benefits*. The interest income component of return on plan assets is still reflected in profit and loss, whilst all other related plan asset income (for example, dividends, other income) is now reflected directly in other comprehensive income. The interest income component now forms part of net interest expense (income) that is calculated based on the net defined benefit liability (asset) by applying the discount rate used to discount the defined benefit obligation at the beginning of the annual period.

Impact of the change

The impact of the change in AASB 119 is reflected in increase in employee benefits expense of $11M and subsequent increase to all Opex and Capex categories through overhead allocations.

Opex for HV Customers

The AER requires Energex to provide the following variables relating to opex for High Voltage Customers:

3.2.4 Opex for High Voltage Customers (required for SCS only)

DOPEX0401 – Opex for High Voltage Customers

This variable is a part of worksheet 3.2 – Opex and is to be reported for regulatory year 2014.

The data reported for this variable is estimated.

Consistency with EB RIN Requirements

The AER has specified the following requirements in relation to reporting opex for high voltage customers:

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 incurred 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, and as a result does not keep a any records relating to electricity distribution transformers which are owned by its high voltage customers. As such, for reporting purposes, Energex has estimated the Opex which would otherwise have been expensed, had the company been responsible for their maintenance. The estimate of this avoided cost is derived by applying a theoretical ratio of operating expenditure to transformer capacity for Energex owned transformers used by LV metered, site specific customers, to the assumed capacities of customer owned transformers. The ratio is calculated using known capacity data and by allocating a nominal portion of total Opex required for maintenance, based on the replacement cost of the transformers as a total of the overall asset base. Only LV metered site specific customers were considered due to relevance and the completeness of the data set available (not many HV metered customers are Energex owned).

Sources

Table 3.2.4 Opex for high voltage customers for 2014			
Variable Code	**Variable**	**Unit**	**Source**
DOPEX0401	Opex for high voltage customers	$'000	Peace report and Pricing model

Methodology

Opex in table 3.2.4 was estimated using data for known Energex high voltage customers.

Assumptions

Approach

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 it is therefore estimated by multiplying an assumed ratio of maintenance costs per MVA of transformer capacity, derived from actual data for LV metered, site specific customers using Energex managed distribution transformers. The approach involves two steps; estimating customer owned transformer capacity based on known demand data, and deriving the aforementioned ratio. The following points detail the methodology used for the 2014 reporting.

1) A report from Peace was obtained from Energex Network Forecasting that contains maximum demand figures for high voltage demand customers. NMIs with the following network tariff codes (NTCs) were determined as high voltage demand 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

2) The list of NMIs received from Energex Network Forecasting was also cross-checked against a list of HV Metered customers obtained from Network Pricing. Only those NMIs that had a HV NTC and were known to be a HV metered 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 2014 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%. Maximum demand figures extracted in steps 1 and 2 were then divided by 0.47 to obtain estimated customer owned transformer capacities.

4) The operating unit cost per MVA of capacity, required to maintain Energex-managed distribution transformers was estimated using the following formula:

$$\$/MVA = \frac{Total\ operating\ cost\ \times \frac{Replacement\ cost\ of\ Energex\ LV\ metered\ site\ specific\ customer\ transformers}{Replacement\ cost\ of\ total\ Energex\ assets}}{Total\ capacity\ of\ Energex\ LV\ metered\ site\ specific\ customer\ transformers}$$

5) The unit operating cost per MVA of capacity calculated in step 4 was multiplied by the total estimated customer transformer capacity calculated in step 3 to produce a hypothetical Opex for customer owned distribution transformers that would have been expensed in each regulatory year.

Estimates

All figures provided in 3.2.4 for high voltage customers are estimated.

Justification for estimates

The opex for High voltage customers where Energex does not own the distribution transformer is not measured by Energex and is inherently estimated.

Basis for estimates

Table	Item	Reason
Table 3.4 – High voltage customers	All items	Estimated by multiplying an estimate of HV customer owned transformer capacity by the operating unit cost per MVA of capacity observed in Energex-managed distribution transformers.

Explanatory notes

NA

Accounting policies

There has been no accounting policy change that impacts on this variable.

3.2.3 Provisions

As per the AER (Australian Energy Regulator) requirements, Energex is providing the following variables relating to provisions for Standard Control Services (SCS):

Table 3.2.3 Provisions

DOPEX0301-14A	Provision for dividends
DOPEX0301-14B	Provision for Site Restoration – Toowoomba
DOPEX0301-14C	Provision for Site Restoration - Other
DOPEX0301-14D	Provision for Public Liability Insurance
DOPEX0301-14E	Provision for Employee Benefits
DOPEX0301-14F	Provision for Redundancy
DOPEX0301-14G	Provision for Overhead Service Line Inspections
DOPEX0301-14H	Provision for Environmental Offsets
DOPEX0301-14I	Provision for Other

These variables are a part of worksheet 3.2.3 Provisions and are reported for regulatory year 2014.Note that the Economic Benchmarking Regulatory Information Notice (EB RIN) template that was issued together with the EB RIN in November 2013 has been changed for 2014. In the new EB RIN template, Provisions is now in worksheet 3.2.3 instead of 3. The EB RIN itself including Instructions and Definitions has not changed. Therefore the table references in the AER requirements section in this basis of preparation (per the EB RIN) are different to the actual table references, which are per the new template for 2014.

The following data is estimated:

- DOPEX0301-14C Provision for Site Restoration - Other
- DOPEX0301-14D Provision for Public Liability Insurance
- DOPEX0301-14E Provision for Employee Benefits
- DOPEX0301-14I Provision for Other

All other data is actual information.

Consistency with EB RIN Requirements

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

AER Requirements (refer Appendix B of the EB RIN: Economic Benchmarking Data Template Instructions and Definitions)	Consistency with AER Requirements
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 financial information on provisions for Standard Control Services. From 2014, provisions were no longer required to be reported in the annual Regulatory Accounting Statements. However, the principles regarding provisions in previous years' Regulatory Accounting Statements apply to 2014 provisions. Provisions are allocated to services based on Property, Plant & Equipment (PP&E) balances, consistent with the methodology applied in apportioning balance sheet items among services adopted in previous years' Regulatory Accounting Statements. Therefore the provision amount attributed to SCS is based on the proportion of the SCS PP&E to the total PP&E. 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 2014, sourced from the supporting workings for the 2014 Regulatory Accounting Statements.

Sources

Reporting for all provisions is based on the 2014 statutory financial statements and Regulatory Accounting Statements workings.

Methodology

Methodology for the provisions reporting is detailed below.

Assumptions

The difference in PP&E allocation percentages between the current and prior regulatory years is treated as follows:

- adjustments that resulted in increased provisions are assumed to be additions to provisions; and
- adjustments that resulted in decreased provisions are assumed to be unused amounts reversed.

Approach

Provisions are allocated to services based on PP&E balances, which is consistent with the annual Regulatory Accounting Statements up to 2013. 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.

Provisions typically relate 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 workings for the annual Regulatory Accounting Statements. 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 Components
DOPEX0301-14A	Provision for dividends	Neither Opex nor Capex. It is related to Net Operating Profit After Tax and charged directly to Retained Earnings. Its movements are reported in the EB RIN under Other Component.
DOPEX0301-14B	Provision for Site Restoration - Toowoomba	Charged to Other as it represents unregulated expenditure for a former gas site.
DOPEX0301-14C	Provision for Site Restoration - Other	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.
DOPEX0301-14D	Provision for Public Liability Insurance	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.
DOPEX0301-14E	Provision for Employee Benefits	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations. 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” is not specifically disclosed in the statutory financial statements. For the EB RIN reporting purposes, this variable is based on inflation and discounting of the leave entitlements per the workings supporting employee benefits balances in the statutory financial statements, multiplied by the PP&E allocation rate and the Opex/Capex overhead allocation rate. The amount for leave

Variable Code	Variable	Capex and Opex Components
		entitlements is the accrued leave balance per payroll records plus on-costs such as payroll tax, superannuation and workers' compensation.
DOPEX0301-14F	Provision for Redundancy	Charged to other support cost directly, therefore 100% allocated to Opex.
DOPEX0301-14G	Provision for Overhead Service Line Inspections	Charged to inspection costs directly, therefore 100% allocated to Opex.
DOPEX0301-14H	Provision for Environmental Offsets	Charged to Opex and Capex directly based on relevant components, not through overhead allocations. The adjustment for the PP&E allocation difference between 2014 and 2013 has decreased the provision. As the amount is minor, it has been combined with the unused amount in the Opex component instead of being apportioned between the Opex and Capex components.
DOPEX0301-14I	Provision for Other	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.

Estimates

Within provisions, some amounts were estimated in their apportionment between Opex and Capex.

All other amounts are actual information.

Justification for estimates

The apportionment for provisions charged to indirect expenditure is based on the overhead allocation to Capex and Opex therefore it is estimated.

Basis for estimates

The overhead allocation rate for each service (SCS, ACS and Non-regulated Services) is calculated as the percentage of the allocation amount to a specific service (identified through activity codes for each service) over the total allocation (identified through the overhead allocation element).

Explanatory notes

The following explanations are provided in relation to provisions:

- Provision for Site Restoration - Toowoomba (DOPEX0301B – DOPEX0314B) – The rehabilitation provision for the Neil Street property in Toowoomba raised in 2012 has been utilised for the remedial works. The remaining balance as at 30 June 2014 is supported by estimates of costs to be incurred in 2015. There are no other legal or constructive obligations which give rise to any further provisions for the year ending 30 June 2014.

- Provision for Public liability Insurance (DOPEX0301D – DOPEX0314D) – The significant increase this year is due to a change in public liability provisions process following an extensive review to streamline the process. The provision now includes claims less than $100k and the first $100k of large/multi claims (including potential claims going back to 2009).

- Provision for Redundancy (DOPEX0301F – DOPEX0314F) – There has been a significant decrease in this provision in 2014 due to redundancy payments.

- Provision for Overhead Service Line Inspections (DOPEX0301G – DOPEX0314G) was initially recognised in 2012 to inspect faulty overhead service lines, with a corresponding increase in inspection costs (Opex). The majority of these inspections were completed in 2013, with the remainder completed in 2014.

- Provision for Environmental Offsets (DOPEX0301H – DOPEX0314H) was initially recognised in 2012 for environmental obligations required to offset the unavoidable negative impacts on the natural environment resulting from Capex projects. Utilisation occurs when offset projects have been undertaken to satisfy Energex's offset obligations. The increase in provision in 2014 includes amounts which represent payments in advance of existing environmental offset obligations that have been transferred to prepayments. Amounts reversed were to reflect adjustments to the original provision that was raised following revised estimation.

- Provision for Other (DOPEX0301I – DOPEX0314I) – Reduction was mainly due to utilisation of this provision in relation to an onerous contract.

3.3 Assets

3.3 Assets (RAB) Values

As per the AER (Australian Energy Regulator) requirements, Energex is providing the following variables for Standard Control Services (SCS), Alternative Control Services (ACS) and Network Services (NS):

Table 3.3.1 Regulatory Asset Base Values

- DRAB0101 – Opening value
- DRAB0102 – Inflation addition
- DRAB0103 – Straight line depreciation
- DRAB0105 – Actual additions (recognised in RAB)
- DRAB0106 – Disposals

Table 3.3.2 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

Table 3.3.3 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 – Value of Capital Contributions or Contributed Assets

These variables are a part of worksheet 3.3 Assets (RAB) and have been calculated using the AER Regulated Asset Base (RAB) Roll Forward Model (RFM). The exception is DRAB13 – Value of Capital Contributions or Contributed Assets, which was obtained directly from the annual Regulatory Accounting Statements and/or supporting workings.

Note that the Economic Benchmarking Regulatory Information Notice (EB RIN) template that was issued together with the EB RIN in November 2013 has been changed for 2014. In the new EB RIN template, Assets RAB is now in worksheet 3.3 instead of 4. The EB RIN itself including Instructions and Definitions has not changed. Therefore the table references in the AER requirements section in this basis of preparation (per the EB RIN) are different to the actual table references, which are per the new template for 2014.

The following data is estimated:

- **All data for NS**
- **For SCS**
  - **Table 3.3.2 Asset value roll forward for DRAB0401-7 distribution substations and transformers**
  - **Table 3.3.2 Asset value roll forward for DRAB0701-7 zone substations and transformers**
  - **Table 3.3.3 Total disaggregated RAB for DRAB1203 distribution substations including transformers**
  - **Table 3.3.3 Total disaggregated RAB for DRAB1206 zone substations**

Consistency with EB RIN Requirements

EB RIN Requirements

The AER requires Energex report its Regulated Asset Base (RAB) both in total amounts and disaggregated into the asset categories defined in the Economic Benchmarking RIN templates. The definitions of these asset categories can be seen in Appendix A 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 tables 4.1, 4.2 and 4.3 (now tables 3.3.1, 3.3.2 and 3.3.3) 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."

Consistency

Energex has produced the RAB amounts for the EB RIN based on the RAB RFM used for the 2010 Determination. SCS amounts 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 annual Regulatory Accounting Statements for years 2010 – 2014.

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 Appendix A. This approach aligns to the standard approach defined by the AER above and as such the optional additional approach has not been used.

ACS has only existed in Energex from regulatory year 2011. From their inception the ACS in Energex have contained street lighting services, quoted and fee based services. As the AER only developed a RAB for street lighting services based on the limited building block approach, only street lighting services are included in the RFM, consistent with the EB RIN Instructions and Definitions. 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 3.3.3.

For SCS and ACS, although the original 2005 RAB values included forecast data, for the purposes of the EB RIN the data has been treated as actual information for the following reasons:

- 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.)

Sources

All data prior to 2010 has been sourced from the RFM prepared for the AER for the 2010 Determination. For subsequent years the inputs to the RFM have been sourced as follows:

- Actual capex and disposals – Sourced from the annual Regulatory Accounting Statements;
- CPI information – Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities periods March to March), in line with the AER approach; and
- WACC – Sourced from the AER 2010 Determination[1]

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

Table 3.3.1: Regulatory Asset Base Values		
Variable Code	**Variable**	**Source**
DRAB0101	Opening value	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0102	Inflation addition	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0103	Straight line depreciation	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0104	Regulatory depreciation	Net of DRAB0102, DRAB0103
DRAB0105	Actual additions (recognised in RAB)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0106	Disposals	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0107	Closing value for asset value	Calculated from DRAB0101 to DRAB0106

Table 3.3.2: Asset value roll forward		
Variable Code	**Variables**	**Source**
DRAB0201-7	Overhead network assets less than 33 kV	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0301-7	Underground network assets less than 33 kV	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0401-7	Distribution substations and transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0501-7	Overhead network assets 33 kV and above	Regulatory Accounting Statements, ABS, 2010 Determination

Table 3.3.2: Asset value roll forward		
Variable Code	**Variables**	**Source**
DRAB0601-7	Underground network assets 33 kV and above	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0701-7	Zone substations and transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0801-7	Easements	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB0901-7	Meters	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1001-7	“Other” asset items with long lives	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1101-7	“Other” asset items with short lives	Regulatory Accounting Statements, ABS, 2010 Determination

Table 3.3.3: Total disaggregated RAB asset values		
Variable Code	**Variable**	**Source**
DRAB1201	Overhead distribution assets less than 33 kV (wires and poles)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1202	Underground distribution assets less than 33 kV (cables, ducts etc)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1203	Distribution substations including transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1204	Overhead assets 33 kV and above (wires and towers / poles etc)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1205	Underground assets 33 kV and above	Regulatory Accounting Statements, ABS, 2010

Table 3.3.3: Total disaggregated RAB asset values		
Variable Code	**Variable**	**Source**
	(cables, ducts etc)	Determination
DRAB1206	Zone substations	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1207	Easements	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1208	Meters	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1209	Other assets with long lives (please specify)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1210	Other assets with short lives (please specify)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB13	Value of Capital Contributions or Contributed Assets	Regulatory Accounting Statements and/or Supporting Workings

Methodology

Energex has produced the values for worksheet 3.3 based on the RAB RFM used for the 2010 Determination and in line with the RFM handbook. Following the initial EB RIN work for 2006 to 2013, this RFM was extended further to 2014, using actual information from the Regulatory Accounting Statements 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 of this sub-category 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 street lighting 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 to 2014 years.

Assumptions

NS RAB values are a subset of SCS and have been estimated by excluding any capex relating to connection assets.

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 and includes the values for:
   - Opening Asset Value;
   - Asset Remaining Life;
   - Asset Standard Life;
   - Forecast Net Capex; and
   - Forecast Regulatory Depreciation.

2) Data for 2010 existed in the original RFM, however these were forecast amounts used for the 2010 Determination. These amounts were replaced with actual amounts from the Regulatory Accounting Statements. Data for 2014 were populated with actual amounts from the Regulatory Accounting Statements.

   CPI and WACC for 2014 were input into the model. CPI was obtained from the ABS.

   Capital contributions have <u>not</u> been included in the input sheet of the RAB RFM as Energex reports the RAB inclusive of these contributions and capital contributions rows in the input sheet of the RAB RFM are a deduction from gross capex. The input of these amounts in this model would cause the amounts to be inconsistent with those approved by the QCA (Queensland Competition Authority) and AER. Capital contributions have been calculated from the Regulatory Accounting Statements and are stated in variable DRAB13.

3) Using the input amounts in step 2) the RFM calculates the following for each RFM asset category for regulatory year 2014[2]:
   - Nominal Opening Regulated Asset Base (equals 2013 closing 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 CPI.

[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 Actual Straight-line Depreciation

  Calculated as the sum of:

  a) the opening RAB depreciation inflated by CPI, and

  b) depreciation incurred on prior year's capex, half WACC adjusted (assuming an average mid-year capitalisation date) and inflated by CPI

- Nominal Actual Gross Capex

  Calculated as the actual real term capex with half WACC adjustment, and adjusted by Actual CPI (1 year lagged).

- Nominal Actual Disposal

  Calculated as the actual real term disposals with half WACC adjustment and adjusted by actual CPI (1 year lagged).

4) The amounts calculated in step 3) then formed the variables stated in tables 3.3.1, 3.3.2 and 3.3.3. Table 3.3.1 contains the aggregated RAB amounts, table 3.3.2 disaggregates these amounts into each asset category specified in the EB RIN and table 3.3.3 contains the yearly average RAB value of the disaggregated asset categories.

Table 3.3.1 – Regulatory Asset Base Values

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

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

Table 3.3.2 – Asset value roll forward

This table disaggregates each of the values in table 3.3.1 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 appendix A.

5) Table 3.3.3 – Total disaggregated RAB asset values

The amounts in table 3.3.3 are calculated as the average of the opening and closing RAB totals for each EB RIN asset category for each year by applying the 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 table 3.3.3. These values have been taken directly from the annual Regulatory Accounting Statements.

6) The Written Down Value (WDV) of 110kV Circuit Breakers at 30 June 2014 was identified through the Fixed Assets Register. This value represents 13.35% of the closing RAB value for the EB RIN asset category “Distribution Substations and Transformers”. Each component of “Distribution Substations and Transformers” in the EB RIN template was reduced by 13.35%.

   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) have been reported as Estimated Information .

Network Services

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 RFM 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;
- The amounts for capex in the SCS RFM were adjusted to exclude any capex relating to connection assets to derive the NS values.
- As disposals for SCS assets are insignificant and therefore the NS portions would also be insignificant, they have not been adjusted except for metering and low voltage services, which are connection assets and are entirely excluded.

Adjustment to the opening RAB 2005

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

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	Annual Regulatory Accounting Statements Asset Category	EB RIN Asset Category
110/132 kV	Underground Subtransmission Cables	Underground Substransmission Cables
	OH Subtransmission Line	OH Subtransmission Line
33 kV Bus	Substation Bays	Substation Bays
33 kV Line	Underground Subtransmission Cables	Underground Substransmission Cables
	OH Subtransmission Line	OH Subtransmission Line
11 kV Bus	Distribution Substation Switchgear	Distribution Substation Switchgear
11 kV Line	Underground Distribution Cables	Underground Distribution Cables
	OH Distribution Line	OH Distribution Line
LV	Distribution Transformers	Distribution Transformers
Services	Low Voltage Services	Low Voltage Services
Meters	Metering	Metering
Relays	Low Voltage Services	Low Voltage Services

As shown 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 components, a percentage split was estimated from the replacement costs in the 2013 pricing model. These can be seen below:

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 relevant EB RIN asset category (refer first column in the table below). 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 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 connection assets	**857,893,939**	
Total connection assets excl. meters and LV	**469,101,598**	
Total RAB System Assets	**4,155,595,864**	
Total RAB System excl Meters & Low Voltage Services	**3,766,803,523**	

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 (within asset classes 1 to 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.

Adjustment to the opening 2005 forecast capex and regulatory depreciation

6) Actual capex amounts for connection assets were sourced from regulatory year 2005 using a standard constructed assets WIP (FIN027) report. This report is the basis for capex reporting in the Regulatory Accounting Statements. 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

7) The total capex in these four activities was then subtracted from those asset categories identified in step 4) 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 amount 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. The formula is summarised below:

Forecast Net Capex $_{NS}$ = SCS Capex for individual asset class that contains connection assets – (Total connection assets capex minus 100% LV and metering capex) SCS Capex for individual asset class that contains connection assets / SCS Capex for all asset classes containing connection assets minus 100% LV and metering capex*

8) 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:

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

Adjustment to annual capex amounts

9) The annual capex amounts were adjusted in an identical manner to the net capex amounts in step 6 above. The total capex amounts for connection assets were generated using the EPM PoW10 report (2014 equivalent of FIN027 report referred above) and subtracted from those asset classes determined to contain connection assets. Low voltage service and metering assets were reduced by 100% and the capex for the remainder was subtracted from the remaining asset categories as a proportion of their values.

The modified NS RFM workbook then calculated the amounts for tables 3.3.1 and 3.3.2 in an identical manner as described for SCS. Amounts for table 3.3.3 were also calculated as the average of the opening and closing NS RAB totals for each EB RIN asset category.

Capital Contributions

10) 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 is as follows:

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

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 are no 110kV Circuit Breakers. Therefore, the amounts adjusted in the "Distribution Substations and Transformers" and the "Zone Substations and Transformers" for the SCS template were applied to the NS template.

Alternative Control Services

ACS has only existed in Energex from the 2011 regulatory year. From their inception the ACS in Energex have contained street lighting services, quoted and fee based services. As the AER only developed a RAB for street lighting services based on the limited building block approach, only street lighting services are included in the RFM, consistent with the EB RIN Instructions and Definitions.

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

- Actual capex for regulatory years 2011 – 2014 sourced from the Regulatory Accounting Statements (note that the PTRM input requires real amounts adjusted for inflation rather than the nominal amounts).
- The ACS capex numbers required to be reported in the Regulatory Accounting Statements for 2011 and 2012 do not include overheads. These numbers were sourced from the workings supporting the Regulatory Accounting Statements. ACS capex for 2013 and 2014 were stated in the Regulatory Accounting Statements inclusive of overheads and therefore no other source data was required;
- CPI numbers based on those used for SCS; and
- WACC numbers based on those used for SCS.

Capital contributions for ACS were sourced directly from the Regulatory Accounting Statements and/or supporting workings.

Estimates

1) All data stated for NS is considered estimated information.

2) Data for "Distribution Substations and Transformers" and "Zone Substations and Transformers" for SCS is considered to be estimated.

Justification for estimates

1) Energex has not captured the RAB for NS as it has not historically been required to report this category separately.
2) 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.

Methodology for estimates

1) 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 amounts 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 amounts for capex used in the SCS RFM were adjusted to include only those values relating to NS by excluding 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 contribution stated for NS was estimated by applying the percentage of NS RAB over SCS RAB to the SCS capital contributions amount.

   For a detailed explanation of the construction of NS RAB amounts please refer to Approach above.

2) In relation to 110kV Circuit Breakers, an adjustment has been made based on the 30 June 2014 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 Approach above.

Explanatory notes

1) Actual additions for Meters (DRAB0905) is higher than previous years due to a one off transfer from Overhead Network Assets Less Than 33kV (DRAB0205). The transfer amount of $331.4M represents 10 years of capex (from 2003/04) for meters and the relevant portion of load control devices previously included in low voltage

overhead services. This capex was previously combined with low voltage overhead services as the works are typically completed together. Disaggregation was performed in preparation for the reclassification of metering services to ACS from 2015/16.

2) The following adjustments have been made to the asset values:
   a) Closing RAB values for SCS and NS from 2011 were adjusted for the appropriate treatment of capital contributions. The 2011 and 2012 Capex as previously reported in the EB RIN information for the initial years (2006 to 2013) consisted of total capex net of capital contributions. Capital contributions were $64.4M for 2011 and $61.4M for 2012. The 2011 and 2012 capex have been re-stated to be gross capex including capital contributions consistent with the approach outlined in the Approach section above.
   b) In the EB RIN information previously reported for the initial years (2006 to 2013) the Street Lighting asset category in the SCS was not adjusted to exclude the ACS street lighting ($98.74M) from the 2011 opening value. The 2011 opening RAB for SCS has been adjusted to exclude the ACS street lighting.
   c) The PTRM used to roll forward the ACS street lighting assets has an opening asset value of $96.8M, which includes the forecast capex for 2010. In the 2014 workings, this value has been updated to $98.74M, which is based on the actual capex for 2010.
   d) The net effect of the above adjustments is an increase in the 2014 opening RAB values for SCS, NS and ACS of $25.04M, $24.96M and $1.52M respectively.

Accounting policies

The Group changed its accounting policy in 2014 with respect to the basis for determining the cost related to its defined benefit fund.

Nature of the change

The change is as a result of revisions to Accounting Standard AASB 119 Employee Benefits. The interest income component of return on plan assets is still reflected in profit and loss, whilst all other related plan asset income (for example, dividends, other income) is now reflected directly in other comprehensive income. The interest income component now forms part of net interest expense (income) that is calculated based on the net defined benefit liability (asset) by applying the discount rate used to discount the defined benefit obligation at the beginning of the annual period.

Impact of the change

The impact of the change in AASB 119 is reflected in increase in employee benefits expense of $11M and subsequent increase to all Opex and Capex categories through overhead allocations.

Appendix A – RAB EB RIN Asset Category Definitions and Mapping of EB RIN Asset Categories to Annual RIN 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 work on the power lines at all times.	Easements (System)

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
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 Street Lighting Other Equipment Control Centre - SCADA Buildings Land Equity Raising Costs
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

3.3.4 Asset Lives

As per the AER (Australian Energy Regulator) requirements, Energex is providing the following variables regarding asset lives for Standard Control Services (SCS), Alternative Control Services (ACS) and Network Services (NS):

Table 3.3.4 Asset Lives

- **Table 3.3.4.1 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**
- **Table 3.3.4.2 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 3.3 – Assets (RAB) and have all been calculated using the AER Asset Lives Roll Forward Model (RFM).

Note that the Economic Benchmarking Regulatory Information Notice (EB RIN) template that was issued together with the EB RIN in November 2013 has been changed for 2014. In the new EB RIN template, Assets RAB is now in worksheet 3.3 instead of 4. The EB RIN itself including Instructions and Definitions has not changed.

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

All data stated for ACS is considered actual information.

Consistency with EB RIN Requirements

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."

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 $\boldsymbol{j} = \sum_{\boldsymbol{i=1}}^{\boldsymbol{n}} \frac{\boldsymbol{x_{i,j}}}{\boldsymbol{RC_j}} . \boldsymbol{EL_{i,j}}$

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 Appendix A.

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 Asset Lives RFM submitted to the AER as a part of the 2010 Determination[4] 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 Asset Lives RFM submitted to the AER as a part of the 2010 Determination process, which have been updated to reflect the residual lives. 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 Basis of Preparation for Assets (RAB) Values).

Sources

All data prior to 2010 has been sourced from the RFM prepared for the AER for the 2010 Determination. For subsequent years the inputs to the RFM have been sourced as follows:

- CPI information – Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities periods March to March) in line with the AER approach and regulatory reporting;
- Capex and disposal – Sourced from the annual Regulatory Accounting Statements; and
- WACC – Sourced from the 2010 Determination.

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

Table 3.3.4.1 Asset Lives – estimated service life of new assets		
Variable Code	**Variable**	**Source**
DRAB1401	Overhead network assets less than 33kV (wires and poles)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1402	Underground network assets less than 33kV (cables)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1403	Distribution substations including transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1404	Overhead network assets 33kV and above (wires and towers / poles etc)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1405	Underground network assets 33kV and above(cables, ducts etc)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1406	Zone substations and transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1407	Meters	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1408	“Other” assets with long lives	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1409	“Other” assets with short lives	Regulatory Accounting Statements, ABS, 2010 Determination

Table 3.3.4.2 Asset Lives – estimated residual service life		
Variable Code	**Variable**	**Source**
DRAB1501	Overhead network assets less than 33kV (wires and poles)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1502	Underground network assets less than 33kV (cables)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1503	Distribution substations including transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1504	Overhead network assets 33kV and above (wires and towers / poles etc)	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1505	Underground network assets 33kV and	Regulatory Accounting Statements,

Table 3.3.4.2 Asset Lives – estimated residual service life		
Variable Code	**Variable**	**Source**
	above (cables, ducts etc)	ABS, 2010 Determination
DRAB1506	Zone substations and transformers	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1507	Meters	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1508	“Other” assets with long lives	Regulatory Accounting Statements, ABS, 2010 Determination
DRAB1509	“Other” assets with short lives	Regulatory Accounting Statements, ABS, 2010 Determination

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 RFM and Asset Life RFM produced for the AER for the 2010 Determination. These RFMs were extended from 2010 to 2014 using actual information from the Regulatory Accounting Statements.

Assumptions

Standard service life of RAB assets is constant and equal to those specified in the 2010 Determination RFM.

Approach

Standard Control Services

1) The estimated service life of new assets was calculated using the standard service life published in the 2010 Determination RFM. This service life was applied to 2014. The asset life categories in the 2010 Determination RFM were then aggregated into the categories required for the EB RIN. The aggregation used a weighted average of each of the applicable asset categories, weighted by their 2014 opening RAB value (note, previously the average RAB value over the eight years was used for the weighting for the working for the initial years of 2006 to 2013). For the mapping of the 2010 Determination RFM asset categories to the EB RIN categories refer to Appendix A.

2) The residual service life of RAB assets was calculated using the Asset Life RFM template used for the 2010 Determination using estimated standard lives for additions and residual lives of existing assets. The calculations were extended to

2014 to complete the EB RIN data requirements. This template relies on information calculated in the extended RAB RFM for SCS, ACS and NS, as detailed in Basis of Preparation for Assets (RAB) Values. 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 weighted average of:
   - The prior year's average residual life minus one; and
   - The standard life of any new acquisitions.
   - The weightings are based on the RAB value of the current year's assets (prior year RAB minus disposals, depreciation and applicable adjustments) and the newly acquired assets.

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 Appendix A.

Network Services

5) NS are defined as a subset of SCS. A separate RAB RFM has been developed on the assumptions in relation to NS contained in Basis of Preparation for Assets (RAB) Values. 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 for Assets (RAB) Values.

   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.

Alternative Control Services

6) For Energex, ACS asset categorisation starts from 2011 and since its inception only includes Street Lighting assets. A separate RFM was developed for ACS using the template supplied by the AER for the 2010 Determination. This model was then updated using actual Street Lighting asset data for regulatory years 2010 – 2014 sourced from the Regulatory Accounting Statements.

   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 for Assets (RAB) Values.

Estimates

All variables in SCS and NS are considered estimates. Variables for SCS are considered to be estimates, as the variables comprise the weighted average of the individual assets within each category. Variables for NS are considered to be estimates, as RAB information for NS is estimated.

Justification for estimates

Energex captures the assets information at a more detailed level than that required for the EB RIN reporting thereby necessitating aggregation and estimation through the application of the weighted average method.

Energex historically has not captured RAB information separately for NS.

Methodology for estimates

Standard Control Service

Where the categories comprise of a number of assets, asset lives for the whole category is calculated by weighting the lives of individual assets within that category. Weightings are calculated on the basis of the assets' shares of the RAB for the category and expected asset lives.

Network Services

The NS standard 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 Basis of Preparation for RAB Values.

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

Explanatory notes

Following adjustments made to the 2011 and 2012 capex numbers (refer to the BoP for 3.3 Asset Values), asset lives have also been updated.

Appendix A – RAB EB RIN Asset Category Definitions and Mapping of EB RIN Asset Categories to Annual RIN Categories

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
Overhead network assets less than 33kV (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 33kV (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 33kV 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 33kV 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 work on the power lines at all times.	Easements (System)

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
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 Street Lighting 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

3.4 OPERATIONAL DATA

3.4.1 Energy Delivery

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

3.4.1 Energy Delivery

- **DOPED01 – Total energy delivered**

3.4.1.1 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**

3.4.1.2. 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**

3.4.1.3. 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**

3.4.1.4. 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**

These variables are a part of Regulatory Template 3.4 – Operational Data.

All other information is Actual Information.

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.
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 3.4.	The customer types are consistent to those used in RIN Table 3.4.

Sources

Variable Code	Variable	Unit	Source
DOPED01	Total energy delivered	GWh	PEACE

RIN Table 3.4.1.1 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 3.4.1.2 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
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	GWh	-

RIN Table 3.4.1.3 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 3.4.1.4 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

RIN Table 3.4.1.4 Energy grouping – customer type or class			
Variable Code	**Variable**	**Unit**	**Source**
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

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 Table 3.4.1.1 and table 3.4.1.4 and energy purchased is reported in RIN Tables 3.4.1.2 and 3.4.1.3. Each of these figures is broken down into the categories specified by the AER.

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.

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. A large proportion of Energex customers (residential and small business are quarterly read accumulation metering and Energex are required to estimate the final end of financial year total until October each year.

Energy grouping – delivery by chargeable quantity

The calculation of each line item 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 3.4.1.1 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 DOPED0202-6) 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.

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 3.4.1.2 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

RIN Table 3.4.1.2 Energy – received from TNSP and other DNSPs by time of receipt		
Variable Code	**Variable**	**Calculation methodology**
		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 3.4.1.3 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 generation	Not applicable.
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.

RIN Table 3.4.1.3 Energy – received into DNSP system from Embedded Generation by time of receipt		
Variable Code	**Variable**	**Calculation methodology**
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 3.4.1.4 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.
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.

3.4.2 Customer Numbers

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

RIN Table 3.4.2.1 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 3.4.2.2 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**

RIN Table 3.4.2.4 Unmetered Supply

- **DOPCN0301 – UMS NMIs (e.g. 1 NMI = 1 device)**
- **DOPCN0302 – UMS - these are additional devices to the above NMI**
- **DOPCN0303 – UMS – total devices (NMIs + additional devices)**

These variables are a part of Regulatory Template 5 – Operational Data.

Values reported for customer numbers are Actual Information.

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.

Requirements (instructions and definitions)	Consistency with requirements
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.
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.
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.

Reconciliation of total customer figures between 3.4.2.1 and 3.4.2.2

Historically, the total number of customers broken down by customer type (Table 3.4.2 1) does not match the total broken down by location on the network (Table 3.4.2 2). This problem is due to reconciliation issues between the PEACE (Market CIS system) 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:

- Timing between systems when counting customers (e.g. if 1,000 new customers were made 'Active' today (from 'Greenfield'), the Network Systems don't know about it until the following day – so these NMIs would not be counted in the Network Systems – whereas they would be included in the PEACE figures).
- Missing network information for customers (such as the NAP) - you need the NAP to get the feeder category in some cases

Sources

Three key sources of data were used to produce the number of customers by customer type. PEACE, EMAS/NFM and SLIM. Numbers are actuals, not estimates.

RIN Table 3.4.2.1 Distribution customer numbers by customer type or class			
Variable Code	**Variable**	**Unit**	**Source**
DOPCN0101	Residential customer numbers	number	PEACE
DOPCN0102	Non-residential customers not on demand tariff customer numbers	number	PEACE
DOPCN0103	Low voltage demand tariff customer numbers	number	PEACE
DOPCN0104	High voltage demand tariff customer numbers	number	PEACE
DOPCN0105	Unmetered Customer Numbers	number	SLIM
DOPCN0106	Other Customer Numbers	number	Not Applicable
DOPCN01	Total customer numbers	number	PEACE and SLIM (UMS only)

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

RIN Table 3.4.2.2 Distribution customer number by location on the network			
Variable Code	**Variable**	**Unit**	**Source**
DOPCN0201	Customers on CBD network	number	EMAS/NFM

RIN Table 3.4.2.2 Distribution customer number by location on the network			
Variable Code	**Variable**	**Unit**	**Source**
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

All data relating to Unmetered NMIs and devices was sourced from the Energex SLIM system

Table 3.4.2.4 Unmetered Supply			
Variable Code	**Variable**	**Unit**	**Source**
DOPCN0301	UMS NMIs (e.g. 1 NMI = 1 device)	number	SLIM
DOPCN0302	UMS - these are additional devices to the above NMI	number	Calculation (difference between DOPCN0303 and DOPCN0301)
DOPCN0303	UMS – total devices (NMIs + additional devices)	number	SLIM

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 "de-energised" customers.

Network Tariff code has been used to split the customers across DOPCN0102, DOPCN0103, DOPCN0104. Refer to Appendix B to see exactly how it was done.

UMS count includes an average customer number (between start and end periods) for UMS NMIs and devices additional to the NMI (e.g. so each NMI represents one device – and additional devices follow), excluding streetlights and government lighting (e.g. NTC 9300).

Assumptions

Not Applicable

Approach

RIN Table 3.4.2.1 Distribution customer numbers by customer type or class

Table 3.4.2 1 Distribution customer numbers by customer type or class

This approach required a count of PEACE customers 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.

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.

2) NTC was used to determine the customer voltage. Refer to Appendix B for more details.

3) SLIM provided the count of UMS NMIs (not Street Lights or government lighting (rate 1, 2 , 3). Government owned Rate 8 street lighting was also excluded. Rate 8 privately owned lighting was included.

4) No customers fell into the “Other customers” (DOPCN0106) classification and as such these figures are zero. The AER have advised previously they do not expect data to be provided here.

Table 3.4.2 2 Distribution customer number by location on the network

5) The customer numbers broken down by their location on the network are stored on the Energex EMAS/NFM systems. Energex does not have any customers on long rural networks and therefore all rural flagged customers are classed as short rural.

6) Average customer figures were then calculated for each variable DOPCN0201-3 - the average from the start and end periods was used (e.g. snapshots from 1/7/13 and 30/6/14 were divided by 2). De-en customers were added in after (they are not currently included in our SAIDI/SAIFI/CAIDI customer numbers). UMS are also excluded from these totals and have not been added in.

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

For table 3.4.2.4, 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.

Streetlights and lighting NMIs on rate 1,2,3 and some rate 8 lighting that's government owned (Councils, Main Roads, Queensland Rail, Qld Health etc) are excluded. Rate 8 lighting that is non-government owned (e.g. private body corporate lighting etc) has been included.

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

Appendix B – 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
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

Network Tariff Code (NTC)	Type 1 Classification	Type 2 Classification
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)

3.4.3 Annual system maximum demand

The AER requires Energex to provide the following variables relating to annual system maximum demand:

3.4.3.1. 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**

3.4.3.2 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**

3.4.3.3 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**

3.4.3.4 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 Regulatory Template 3.4 – Operational Data.

All values reported are Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
RIN Tables 3.4.3.1 to 3.4.3.4 must be completed in accordance with the definitions in chapter 9.	Demonstrated in Approach.
Energex must provide inputs for these cells if it has calculated historical Weather Adjusted Maximum Demand.	Demonstrated in Approach.
For RIN Table 3.4.3.1 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 Approach.
For RIN Table 3.4.3.2 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 Approach.
For RIN Table 3.4.3.3 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 Approach.
For RIN Table 3.4.3.4 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 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 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 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 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.
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 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 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 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 Approach.

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

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
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

Methodology

Assumptions

The following assumptions apply to the calculation of 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 – 28/02;
- 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 calculation of the weather adjusted data at the transmission connection point level:

- The data is based the summer period from the 01/12 – 28/02;
- 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.

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 3.4.3.1 and 3.4.3.3):

- The kVA non-coincident Maximum Demand at zone substation level (DOPSD0201) was divided by the total number of customers of the network to find demand density.
- 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 following approach was applied to calculate the annual system maximum demand characteristics at the transmission connection point – MW and MVA (RIN Table 3.4.3.2 and Table 3.4.3.4):

- 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 peak Connection Point demand history. Energex is still developing a temperature adjustment process similar to the AEMO recommended approach for Connection Points. The coincident 10POE and 50 POE temperature adjusted demand is the total system demand. The method used is based on the total system demand temperature adjustment process.

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.

3.4.3.5 Power factor conversion between MVA and MW

The AER requires Energex to provide the following variables relating to power factor conversion:

3.4.3.5 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 3.3 kV lines**
- **DOPSD0304 - Average power factor conversion for 6.6 kV lines**
- **DOPSD0305 - Average power factor conversion for 7.6 kV lines**
- **DOPSD0306 - Average power factor conversion for 11 kV lines**
- **DOPSD0307 - Average power factor conversion for SWER lines**
- **DOPSD0308 - Average power factor conversion for 22 kV lines**
- **DOPSD0309 – Average power factor conversion for 33 kV lines**
- **DOPSD0310 – Average power factor conversion for 44 kV lines**
- **DOPSD0311 – Average power factor conversion for 66 kV lines**
- **DOPSD0312 – Average power factor conversion for 110 kV lines**
- **DOPSD0313 – Average power factor conversion for 132 kV lines**
- **DOPSD0314 – Average power factor conversion for 220 kV lines**

These variables are part of Regulatory Template 3.4 – Operational Data.

The figures provided for all variables are Actual Information, except the average power factor conversions for low voltage distribution line variables are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 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 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 Approach.

All variables have been provided in accordance with the AER's Instructions and Definitions.

The values provided for all variables are Actual Information, except the average power factor conversions for low voltage distribution line variables, which are Estimated Information.

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 3.3 kV lines	Factor	SIFT/SCADA
DOPSD0304	Average power factor conversion for 6.6 kV lines	Factor	SIFT/SCADA
DOPSD0305	Average power factor conversion for 7.6 kV lines	Factor	SIFT/SCADA
DOPSD0306	Average power factor conversion for 11 kV lines	Factor	SIFT/SCADA
DOPSD0307	Average power factor conversion for SWER lines	Factor	SIFT/SCADA
DOPSD0308	Average power factor conversion for 22 kV lines	Factor	SIFT/SCADA

DOPSD0309	Average power factor conversion for 33 kV lines	Factor	SIFT/SCADA
DOPSD0310	Average power factor conversion for 44 kV lines	Factir	SIFT/SCADA
DOPSD0311	Average power factor conversion for 66 kV lines	Factor	SIFT/SCADA
DOPSD0312	Average power factor conversion for 110 kV lines	Factor	SIFT/SCADA
DOPSD0313	Average power factor conversion for 132 kV lines	Factor	SIFT/SCADA
DOPSD0312	Average power factor conversion for 220 kV lines	Factor	SIFT/SCADA

Methodology

Assumptions

The methodology and justification for the low voltage distribution line power factor conversion is discussed below in Approach.

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.

Estimated Information

Basis for the Estimated Information

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

3.4.3.6 Demand supplied

The AER requires Energex to provide the following variables relating to demand supplied:

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

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

3.4.3.7 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 Regulatory Template 3.4 – Operational Data.

The values provided are Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex is only required to complete RIN Table 3.4.3.6 if it charges customers for Maximum Demand supplied. If Energex does not charge customers on this basis then Energex should enter '0'.	Demonstrated in 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 Approach.
Energex is only required to complete RIN Table 3.4.3.7 if it charges customers for demand supplied. If Energex does not charge customers on this basis then Energex must enter '0'.	Demonstrated in 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 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 Actual Information, whereas the MVA measure is based on estimated contracted and measured power factor data.

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 August 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

Methodology

Assumptions

No assumptions were applied to calculating these variables.

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.

3.5 PHYSICAL ASSETS

3.5.1 Circuit Length

The AER requires Energex to provide the following variables relating to circuit length:

3.5.1.1 Overhead network length of circuit at each voltage

- **DPA0101 - Overhead low voltage distribution**
- **DPA0102 - Overhead 2.2 kV**
- **DPA0103 - Overhead 6.6kV**
- **DPA0104 - Overhead 7.6 kV**
- **DPA0105 - Overhead 11 kV**
- **DPA0106 - Overhead SWER**
- **DPA0107 - Overhead 22 kV**
- **DPA0108 - Overhead 33kV**
- **DPA0109 - Overhead 44 kV**
- **DPA0110 - Overhead 66 kV**
- **DPA0111 - Overhead 110 kV**
- **DPA0112 - Overhead 132 kV**
- **DPA0113 - Overhead 220 kV**
- **DPA0114 - Other**
- **DPA01 - Total overhead circuit km**

3.5.1.2 Underground network circuit length at each voltage

- **DPA0201 - Underground low voltage distribution**
- **DPA0202 - Underground 5 kV**
- **DPA0203 - Underground 6.6 kV**
- **DPA0204 - Underground 7.6 kV**
- **DPA0205 - Underground 11 kV**
- **DPA0206 - Underground SWER**
- **DPA0207 - Underground 22 kV**
- **DPA0208 - Underground 33 kV**
- **DPA0209 - Underground 66 kV**
- **DPA0210 - Underground 110 kV**
- **DPA0211 - Underground 132 kV**
- **DPA02 - Total underground circuit km**

These variables are part of RIN Table 3.5.1.1 and RIN Table 3.5.1.2 as set out in Regulatory Template 3.5 – Physical Assets.

The figures provided for all variables are Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 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 Approach. Energex's figures do not include pilot cables as they are a secondary system, as per the definition below.
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 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 Assumptions.

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

The figures provided for all variables are Actual Information.

Sources

The circuit lengths at each voltage level were extracted from 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 2.2 kV	Not Applicable
DPA0103	Overhead 6.6 kV	Not Applicable
DPA0104	Overhead 7.6 kV	Not Applicable
DPA0105	Overhead 11 kV	NFM
DPA0106	Overhead SWER	NFM
DPA0107	Overhead 22 kV	Not Applicable
DPA0108	Overhead 33 kV	NFM
DPA0109	Overhead 44 kV	Not Applicable
DPA0110	Overhead 66 kV	Not Applicable
DPA0111	Overhead 110 kV	NFM
DPA0112	Overhead 132 kV	NFM
DPA0113	Overhead 220 kV	Not Applicable
DPA0114	Other	Not Applicable
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 5 kV	Not Applicable
DPA0203	Underground 6.6 kV	Not Applicable
DPA0204	Underground 7.6 kV	Not Applicable
DPA0205	Underground 11 kV	NFM
DPA0206	Underground SWER	NFM
DPA0207	Underground 22 kV	Not Applicable
DPA0208	Underground 33 kV	NFM
DPA0209	Underground 66 kV	Not Applicable
DPA0210	Underground 110 kV	NFM
DPA0211	Underground 132 kV	NFM
DPA0212	Other	Not Applicable
DPA02	Total underground circuit km	NFM

The NFM database is the master electronic record of all network assets and their connectivity. NFM is populated from completed field work orders and reflects the “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.

Methodology

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).

  Energex limited the impact customer owned conductors would have on 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.

- The conductor data does not include conductors that are in store or held for spares.
- The circuit length data only includes those lines that are in service. Conductors that are in the field but de-energised have not been included.
- 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.

Approach

The following approach was applied to calculate the variables:

1) The data for 2013-14 was obtained by running scripts through the NFM database. In particular:
   - The Line_Lengths_By_Year.sql script was run to extract data for each of the voltage levels (11kv including SWER line) for 13-14. The script extracted data for the overhead and underground circuit length of each voltage level; and
   - A SWER_Line_Lengths_By_Year.sql script was run to extract data for the overhead circuit length of the SWER lines for 2013-14.
2) The SWER length was then deducted from DPA0105 11 kV overhead length and added to DPA0106 Overhead SWER.

The current template requires Energex to segregate the 110kV and 132kV feeders as a separate category. This separation is done based on the allocated voltage level for each feeder as per ERAT2 and is verified through the Energex PSS/E models and DMS systems.

The data was validated by checking the results against the Energex Annual Report and Distribution Annual Planning Report (DAPR). In cases where the unexplained variance was greater than 1%, the differences have been investigated and resolved. Estimated Information

The figures provided for all variables are Actual Information.

Explanatory notes

The figures stated for circuit length in RIN Tables 3.5.1.1 and 3.5.1.2 may differ from those used in the calculation of circuit capacity in RIN Tables 3.5.1.3 and 3.5.1.4. 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 3.5.1.3 and 3.5.1.4 is on an “as operated basis”.

3.5.2 Circuit Capacity – MVA

The AER requires Energex to provide the following variables relating to circuit capacity for low voltage distribution:

3.5.1.3. Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0301 – Overhead low voltage distribution**
- **DPA0302 – Overhead 6.6 kV**
- **DPA0303 – Overhead 7.6 kV**
- **DPA0304 – Overhead 11 kV**
- **DPA0305 – Overhead SWER**
- **DPA0306 – Overhead 22 kV**
- **DPA0307 – Overhead 33 kV**
- **DPA0308 – Overhead 44 kV**
- **DPA0309 – Overhead 66 kV**
- **DPA0310 – Overhead 110 kV**
- **DPA0311 – Overhead 132 kV**
- **DPA0312 – Overhead 220 kV**
- **DPA0313 Other**

3.5.1.4. Estimated underground network weighted average MVA capacity by voltage class

- **DPA0401 – Underground low voltage distribution**
- **DPA0402 – Underground 5 kV**
- **DPA0403 – Underground 6.6 kV**
- **DPA0404 – Underground 7.6 kV**
- **DPA0405 – Unerground 11kV**
- **DPA0406 – Underground SWER**
- **DPA0407 – Underground 12.7 kV**
- **DPA0408 – Underground 22 kV**
- **DPA0409 – Underground 33 kV**
- **DPA0410 – Underground 66 kV**
- **DPA0411 – Underground 110 kV**
- **DPA0412 – Underground 132 kV**
- **DPA0413 – Other**

These variables are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

The figures provided are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 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 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 Approach.

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

The figures provided for all variables are Estimated Information.

Sources

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

Variable Code	Variable	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

Methodology

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 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 the same as those used to prepare the LV circuit line lengths for DPA0101 and DPA0201 variables in RIN Table 3.5.1.1 and 3.5.1.2.

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.

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 Regulatory Years 2014 (this data is covered in the Basis of Preparation for circuit lengths). The circuit line length and conductor data was cross checked for consistency with the total lengths data for overhead and underground conductors provided in the RIN;
2) A conductor rating table was created 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 55 degree rating was assigned to overhead “imperial” conductors and 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 for conductors was assigned in 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 multiplied by 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 using the following formulas:

$$underground\ Rating\ MVA =$$

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

$$overhead\ Rating\ MVA =$$

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

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.

7) The current template requires Energex to segregate the 110kV and 132kV feeders as a separate category. This separation is done based on the allocated voltage level for each feeder as per ERAT2 and is verified through the Energex PSS/E models and DMS systems.

Estimated Information

Justification for Estimated Information

Average thermal de-rating factors for overhead and underground network do not exist as part of the normal planning and 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 Information.

Reasons for Estimated Information

Energex's approach recognises that LV network are typically voltage constrained rather than thermally 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 applied 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.

3.5.3 Circuit Capacity – 11 kV and SWER

The AER requires Energex to provide the following variables relating to circuit capapcty for 11kV and SWER:

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0304 - Overhead 11 kV**
- **DPA0305 - Overhead SWER**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0405 - Underground 11 kV**

These variables are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

The values provided for all variables are Estimated Information.

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 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 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 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 Estimated Information.

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 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
DPA0304	Overhead 11 kV	DINIS
DPA0305	Overhead SWER	NFM

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

Variable Code	Variable	Source
DPA0405	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.

Methodology

Assumptions

The following assumptions underpin the calculation of these figures:

- '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.

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 where possible;

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

- Each cable segment was categorised as overhead or underground;

Different approaches were applied for feeder capacity and are 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

Estimated Information

Justification for Estimated Information

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.

Basis for Estimated Information

For the 2013/14 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 2013/14.

3.5.4 Circuit Capacity – 33 kV

The AER requires Energex to provide the following variables relating to circuit capacity for 33kV:

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0307 - Overhead 33 kV**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0409 - Underground 33 kV**

These variables are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

The figures provided for all variables are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and how the figures are 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 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 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 Approach.

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

The values provided for all these variables are Estimated Infomation.

Sources

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

Variable Code	Variable	Source
DPA0307	Overhead 33 kV	Sincal, GIS/NFM, ERAT2
DPA0409	Underground 33 kV	Sincal, GIS/NFM, ERAT2

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

- 'SIFT or Mailbot – to investigate the commissioning date of feeders

Methodology

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;
- All of the results were based on energised operating voltage.

Approach

The following approach was applied to calculating the variables:

1) The feeder rating data for 2013/14 was obtained from the ERAT2.
2) As 33 kV feeders in the Energex network are point to point sub-transmission circuits. The 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.
3) Line length data was extracted from the GIS or Sincal. Based on feeder names the line length data was linked to ERAT2 data to obtain the feeder rating.
4) To obtain the weighted average MVA, each feeder was divided into its respective UG and OH length components, which is recorded in the GIS.

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

6) 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)

Estimated Information

Justification for Estimated Information

The values provided are based on the available data as there is a lag between project commissioning and when data is uploaded into GIS. On occasions where GIS data is not available, the data is populated based on Energex's Sincal model, which contains data based on Project Scope Statement. The Sincal model contains data on existing and proposed network, and is maintained as project scopes are refined.

Basis for Estimated Information

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 be undertaken to match the historical feeder name to the latest name. There have been numerous changes in the 33 kV network in recent 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.

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.

$$\text{Rating (A)} \times 33000\ \text{(V)} \times \sqrt{3} / 1000000 = \text{Rating (MVA)}$$

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 3.5.1.1 and 3.5.1.2 are different (and higher in value). Unaccounted for lengths included the following:

- Reported line lengths in RIN Tables 3.5.1.1 and 3.5.1.2 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 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, UNNAMED626.)

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

3.5.5 Circuit capacity - 110 kV and 132 kV

The AER requires Energex to provide the following variables relating to circuit capacity for 110/132kV:

Overhead network weighted average MVA capacity by voltage class

- **DPA0306 Overhead 22 kV**
- **DPA0308 Overhead 44 kV**
- **DPA0309 Overhead 66 kV**
- **DPA0310 Overhead 110 kV**
- **DPA0311 Overhead 132 kV**
- **DPA0312 Overhead 220 kV**

Underground network weighted average MVA capacity by voltage class

- **DPA0408 Underground 22 kV**
- **DPA0410 Underground 66 kV**
- **DPA0411 Underground 110 kV**
- **DPA0412 Underground 132 kV**

variables are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

The figures reported for DPA0310, DPA0311, and DPA0411 are Estimated Information, with the remaining figures being Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and how the figures are 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 Approach.

Requirements (instructions and definitions)	Consistency with requirements
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 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 Approach.

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

The values provided for the 110 kV and 132 kV voltage class are Estimated Information. The values provided for the 22 kV, 44 kV, 66 kV and 220 kV voltages classes are Actual Information. The Energex network does not comprise 22 kV, 44 kV, 66 kV or 220kV voltage classes, therefore the values provided for these are 0.

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.

Variable Code	Variable	Source/s
DPA0310	Overhead 110 kV	PSS/E, ERAT 2, NFM/GIS
DPA0311	Overhead 132 kV	PSS/E, ERAT 2, NFM/GIS
DPA0411	Underground 110 kV	PSS/E, ERAT 2, NFM/GIS

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

- SIFT or Mailbot - to investigate feeder variances in relation to past projects, the commissioning date of the secondary systems components relating to a feeder;

Methodology

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;
- All of the results were based on the energised operating voltage.

Approach

The following approach was applied to calculating the variables:

1) The feeder rating data for 13/14 was obtained from ERAT2.
2) The current template requires Energex to segregate the 110kV and 132kV feeders as a separate category. This separation is done based on the allocated voltage level for each feeder as per ERAT2 and is verified through the Energex PSS/E models and DMS systems.
3) 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.
4) Line length data was extracted from Energex GIS system or PSS/E and matched to each feeder name and rating.
5) To obtain the weighted average MVA, each feeder was divided into its respective voltage levels and to its UG and OH length components.
6) Each feeder length component was then multiplied by the feeder rating for the most constrained feeder section, and then aggregated.
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:

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

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

Where,

MVA is the constrained feeder rating of feeder F_n
UG_Length is the total UG length (km) of feeder F_n
OH_Length is the total OH length (km) of feeder F_n
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

Estimated Information

Values provided for the 110 kV and 132 kV voltage class are Estimated Information.

Justification for Estimated Information

The values provided are based on the available data as there is a lag between project commissioning and when the data is uploaded onto GIS. Where actual data is unavailable, estimated values are presented.

Basis for Estimated Information

The ERAT2 and GIS system can only accurately extract data based on the latest (last known) feeder information associated to the segment. On occasions where actual data is not readily available, the data is populated based on Energex's PSS/E model, which contains data based on Project Scope Statement. The PSS/E models contain data on existing and proposed network, and is maintained as project scopes are refined.

Explanatory notes

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA was done assuming nominal voltage of 110 kV and 132 kV.

$$\text{Rating (A)} \times 110000\text{ (V)} \times \sqrt{3} / 1000000 = \text{Rating (MVA)}$$

$$\text{Rating (A)} \times 132000\text{ (V)} \times \sqrt{3} / 1000000 = \text{Rating (MVA)}$$

It should be noted that not all of the circuit length data reported in RIN Tables 3.5.1.1 and 3.5.1.2 of the AER EB RIN data template were used to calculate the weighted average capacities for 110 kV and132 kV due to the following reasons:

- Segments of a valid feeder with no circuit/feeder (ever) being provided. There are a number of segments which do not have a feeder/circuit at that specific point in time in relation to a segment. Further, decommissioned routes, dummy routes, civil works and any segment had a vaild circuit prior to the specified date were not extracted. This was ue to the fact that these feeders do not have a null Feeder/Circuit but a date outside the specified date; and

- Circuit construction voltage was used when extracting the length data. In the DAPR, EB RIN, DAPR and Annual Report, the constructed voltage (segment voltage) was used which does not reflect the energised voltage.

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 3.5.1.1 and 3.5.2.1 are different (and higher in value). These unaccounted for lengths are due to:

- No feeder names being allocated to the feeder length data. (For example, UNAMED319)
- Feeders that are 110 kV 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.

3.5.6 Distribution transformer total installed capacity

The AER requires Energex to provide the following variables relating to 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 3.5.2.1 as set out in Regulatory Template 3.5 – Physical Assets.

The figure provided for DPA0501, DPA0502 and DPA0503 is Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are consistent with those requirements.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report total installed Distribution Transformer Capacity.	Demonstrated in 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 Approach.
The capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).	Demonstrated in 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 Approach.
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in Approach. The data does not include forced cooling as it is not applicable for Energex.
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 Approach.

Requirements (instructions and definitions)	Consistency with requirements
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 Approach.
Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in 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 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 Approach.

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

The values provided contain Actual Information.

Sources

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

Variable Code	Variable	Source
DPA0501	Distribution Transformer Capacity owned by utility	NFM/Ellipse
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 "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.

Methodology

Assumptions

The following assumptions and limitations apply to "Distribution transformer capacity owned by utility" (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 Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- The value is estimated based on the peak demand recorded by the customer for the 2013/14 period.

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

- The number and mix of assets held in stores varies each day. Stock levels are as of the 30th of June 2014;
- Actual Information was available for 2013-14.
- 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.

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 2013-14 period;
- The data was then combined into a master document and arranged into the AER template format; and
- Cold spare capacity was added to the distribution transformer installed capacity to give total distribution transformer capacity owned by Energex.

The following approach was applied to calculating 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 2014;

  Distribution transformer capacity was extracted from the stock code description;

Estimated Information

Justification for Estimated Information

The figures provided for all variables are Actual Information.

3.5.7 Zone substation transformer capacity

The AER requires Energex to provide the following variables relating to 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 3.5.2.2 as set out in Regulatory Template 3.5 – Physical Assets.

The figures provided for DPA0601, DPA0602, DPA0603 DPA0604 and DPA0605 are Actual Information for 2013/14.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 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 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 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 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 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 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 Approach.
The total Cold Spare Capacity included in total zone substation transformer capacity is to be provided.	Demonstrated in 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 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 Approach.

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

The values provided contain Actual Information.

Sources

The zone substation transformer total installed capacities were extracted from the Substation Investment Forecasting Tool (SIFT) 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

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.

Methodology

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 2013-14 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. Stock levels are as of the 30th of June 2014;

- 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.

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 determined 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 2014;
  - Power transformer capacity was extracted from the stock code description; and
- 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.

Estimated Information

The values provided contain Actual Information.

Explanatory notes

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 2013/14

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	8169.4
		Standby (cold capacity)	MVA	-127.5
		total	**MVA**	**8041.9**
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	7906.9
		Standby (cold capacity)	MVA	-179.4
		total	**MVA**	**7727.5**
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	3766.4
		Standby (cold capacity)	MVA	-152.2
		total	**MVA**	**3614.2**
DPA0604	Total zone substation transformer capacity	**total**	**MVA**	**20119.2**
DPA0605	Cold spare capacity of zone substation transformers included	Total standby capacity for first step transformation where there are two	MVA	127.5

	in DPA0604	steps to reach distribution voltage		
		Total standby capacity for second step transformation where there are two steps to reach distribution voltage	MVA	179.4
		Total standby zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	MVA	152.2
		Strategic spares	MVA	276.5
		Normal spares	MVA	0
		total	**MVA**	**735.6**

3.5.8 Public lighting

The AER requires Energex to provide the following variables relating to public lighting:

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

These variables are part of RIN Table 3.5.3 of Regulatory Template 3.5 – Physical Assets.

All values are Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER and the compliance 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 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 Approach.
Only poles that are used exclusively for public lighting are to be included in the data.	Demonstrated in Approach.

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

The values provided for all variables are Actual Information.

Sources

The number of public lighting luminaires and poles was extracted from the 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.

Methodology

Assumptions

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

- Only rating 1[5] and 2[6] 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.

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 by checking the results against the Energex Annual Report and Distribution Annual Planning Report. In cases where the unexplained variance was greater than 1%, the differences was investigated and resolved.

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

3.6 QUALITY OF SERVICES

3.6.1 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 Regulatory Template 3.6 – Quality of Services.

All values reported are Actual Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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

Requirements (instructions and definitions)	Consistency with requirements
	greater than one minute.
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.
Whilst the MED Threshold for Financial year 2013 was derived from financial years 2008 to 2012 and applied to system results for 2013 and all previous years. For the current financial year 2014 the MED level was derived from system results from 2009 to 2013 inclusive but was only applied to system results for 2014.	The MED threshold calculated for 2014 Regulatory Year is in accordance with the STPIS definition and is applied to 2014 system results.

Sources

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

Energex has used outage data from three sources, NFM (Network Facilities Management), EPM (Energex Performance Management) and PON OMS (Power On Outage Management System). These combined sources were queried to retrieve all transformer interruptions with their customer counts and durations.

Methodology

Assumptions

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

2) From the raw source data (253,500 records) there were 276 sustained transformer interruptions that had a valid outage report number but no category due to no feeder allocation at the time of the outage.

   These interruptions were not included in the data used for the yearly SAIDI and SAIFI values. This equated to a CML of 76111 and customer count value of 1271. Represented as a system SAIDI and SAIFI value as below:

   SYSTEM SAIDI = 0.056 minutes

   SYSTEM SAIFI = 0.000938 interruptions

The unallocated system SAIDI and SAIFI as a percentage for normalised data (Excluding excluded data) is represented below:

SAIDI – 0.056/70.04 = 0.08%

SAIFI – 0.0009/0.893 = 0.1%

Source Data

1) CML and CI - From the three corporate data sources transformer interruption data was retrieved for the year resulting in a combined listing of 253,500 records. Energex compiled these transformer records to an "outage table" containing 20,259 sustained interruptions (>1 minute) with each record having a valid outage report number, outage category and outage feeder. Energex doesn't have any long rural feeders.

2) Customer Base – The NFM system customers at the start and end of the reporting period were averaged to create a regulatory customer base. This is listed in column G in the below table.

Approach

1) The CML and CI figures for all outages greater than 1 min in duration were extracted from the outages table 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 table (columns [E] and [F] below).

[A]	[B]	[C]	[D]	[E]	[F]	[G]
FINYEAR	DATE	ALL CML	ALL CI	Excl CML	Excl CI	AER_CUST
2014	28/06/2014	349056.8905	5138			1355285
2014	29/06/2014	324253.2139	5874			1355285
2014	30/06/2014	93787.34241	1476			1355285

3) An AER compliant yearly average customer number was calculated 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 $\frac{\text{CML}}{\text{\# Customers}}$ and $\frac{\text{CI}}{\text{\# Customers}}$ respectively. The daily SAIDI and SAIFI figures were then calculated with the exclusion of specific outages as stated by the AER.

5) 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

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

7) To exclude MEDs from the SAIDI and SAIFI calculations the MED threshold was calculated for the 2014 Regulatory Year in accordance with the STPIS guidelines7. The TMED calculation for 2014 Regulatory Year = 3.41 minutes.

8) Using TMED 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.

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

[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

Estimated Information

For the reported year there are four valid outage reports that have no cause data as below. For these outages a “No Cause” (GN-NR) code was used enabling inclusion in forced outage data.

tblCA_RIN_Combined				
DATE_SH	TIME_SH	OUTAGE_REPORT_SUN	OPERTN_ID	FEEDER_CATEGORY
30/06/2014	16:19	INCD-6061-g	GYGGYS6	RURAL
30/06/2014	08:46	INCD-5890-g	RWD1	RURAL
20/06/2014	17:48	INCD-4165-g	NVL3	URBAN
27/05/2014	08:36	INCD-914-h	TWT12A	RURAL

Justification for Estimated Information

Estimation of cause codes facilitated inclusion of deficient outage reports.

[7] Electricity distribution network service providers - Service target performance incentive scheme, November 2009 – Appendix D: Major Event Days

3.6.2 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 Regulatory Template 3.6 – Quality of Services.

All figures provided are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which these figures are 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 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 Methodology.
Energy not supplied should be reported exclusive of the effect of Excluded Outages as defined in chapter 9	Demonstrated in Methodology.

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

The values provided for all variables are estimated information.

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

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. 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 to the AER's 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.

Assumptions

The following assumptions have been applied to estimating the required variables:

- Completely flat load curves apply, meaning that there is 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.

- At the time of preparation of the 2013/14 figures, customer energy consumption was only available up to March 2014. This is due to customer meter data being manually read on a quarterly basis. Therefore, the period of 1 April 2013 to 31 March 2014 was used as the annual energy consumption for each distribution transformer.

- On 25 May 2014, Energex moved to a new Outage Management System (OMS) to record customer interruption data. At the time of preparation of the 2013/14 figures, the customer interruption data in the new OMS was still undergoing testing and validation. Therefore, for the 2013/14 figures, 12 months of transformer outage data was extracted from the legacy system for the period 25 May 2013 to 24 May 2014.

  Although the outage data from the new OMS has been incorporated in other 2013/14 Energex reliability measures in the RIN, the level of accuracy required for these measures is much more significant. Therefore, Energex expended considerable time and effort in ensuring the reported SAIDI and SAIFI figures included outage data from the new system. Given that Energex is unable to directly measure energy not supplied to customers, the required Energy Not Supplied variables have previously been reported as “estimated”. Therefore, Energex deemed that use of the latest 12 months of outage data from the legacy system in calculating Energy Not Supplied was a reasonable assumption given the level of accuracy required. Regardless, Energex considers that this data is representative of the outage data for the 2013/14 regulatory year.

- Data was only available for the current numbers of transformers per feeder and as such all calculations were based on these figures.

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 2014 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 2014. 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) 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) There is a small portion of the overall supplied energy which has not been able to be assigned to a current distribution transformer or feeder. In 2013/14, this portion was 5.9% of the total energy sales. To adjust for this shortfall, the calculated energy not supplied figures were increased by this portion to determine the final energy not supplied figures.

Estimated Information

The values provided for all variables are estimates.

Justification for Estimated Information

Energex does not measure the energy not supplied to customers directly and has estimated the figures based on the methodologies specified by the AER.

Basis for Estimated Information

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.

3.6.3 System losses and capacity utilisation

The AER requires Energex to provide the following variables relating to system losses and capacity utilisation:

- **DQS03 – System losses**
- **DQS04 – Overall capacity utilisation**

These variables are a part of Regulatory Template 3.6 – Quality of Service.

All figures reported for variables DQS03 and DQS04 are Actual Information.

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 methodology 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 methodology for details.

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)

Methodology

Both variables were calculated using the methodology specified by the AER.

Assumptions

Not Applicable

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:

$$system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$$

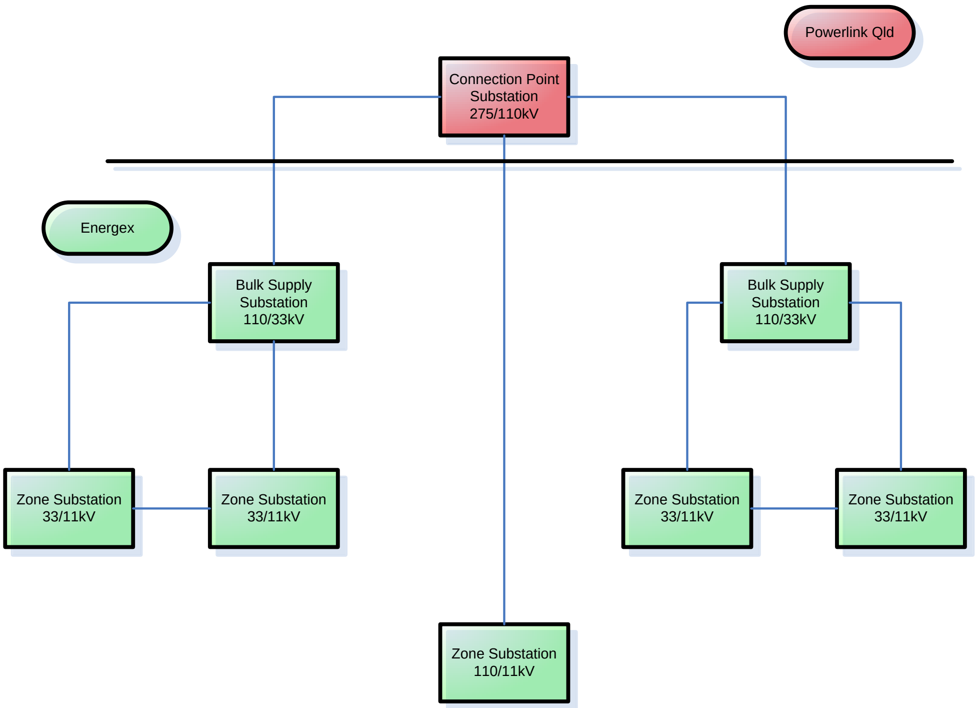
Capacity Utilisation

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).



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.

3.7 OPERATING ENVIRONMENT FACTORS

3.7.1 Rural Proportion

The AER requires Energex to provide the following variables relating to rural proportion:

- **DOEF0201 – Rural proportion of line length**

This is as a part of Regulatory 3.7 – Operating Environment Factors.

All variables are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 Approach.
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.

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

The values provided for all variables are Actual Information.

Sources

Variable Code	Variable	Source
DOEF0201	Rural proportion	ArcGIS

Methodology

All data to calculate the rural proportion variable was obtained through ArcGIS. 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).

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
- Underground route lengths are assumed as urban.

Approach

1) A GIS “shapefile” was generated within 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 ≤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.

Estimated Information

Estimated Information has been provided for the underground portion of route line length.

Justification for estimated information

It was necessary to estimate underground route line length using total underground circuit length.

Reasons for estimated information

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.

Explanatory notes

Energex has only “short rural” line lengths. The value of the rural proportion has altered from previous years due to recalculation of urban / rural areas and a new release of ArcGIS which reportedly provides more accurate information.

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 driven by the overhead network.

3.7.2 Maintenance spans and tree numbers

The AER requires Energex to provide the following variables relating to in relation to maintencance spancs and tree numbers:

- **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 Regulatory Template 3.7 – Operating Environment Factors.

All figures reported for these variables are estimated information based on statistical sampling.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 Approach.
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 and 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 figures provided for all variables are Estimated Information.

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

Methodology

Energex has estimated both the number of vegetation management 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 figures.

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 sub-transmission network.

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 Assumptions 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.

Estimated Information

All data for variables DOEF0202, DOEF0203, DOEF0204, DOEF0208 and DOEF0209 are considered Estimated Information.

Justification for Estimated Information

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

Methodology for Estimated Information

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.

3.7.3 Span numbers, tropical proportion and bushfire risk

The AER requires Energex to provide the following variables relating to span numbers, tropical proportion and bushfire risk:

- **DOEF0205 – Total number of spans**
- **DOEF0212 – Tropical proportion**
- **DOEF0214 – Bushfire risk**

These variables are a part of Regulatory Template 3.7 – Operating Environment Factors and were obtained from the Energex Geographical Information System.

Figures provided for DOEF0205 are Actual Information.

Figures provided for DOEF0212 and DOEF0214 are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the data 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 Approach.
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 Approach.

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.	These have been estimated .

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.

Sources

Variable Code	Variable	Source
DOEF0205	Total number of spans	ArcGIS
DOEF0212	Tropical proportion	ArcGIS/ BOM
DOEF0214	Bushfire risk	ArcGIS/ Queensland Government

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. It is noted that the Queensland Government has made changes to bushfire layers which are refleted in the changed values compared to the previous EBRIN.

Assumptions

Not applicable

Approach

1) The total number of overhead spans was obtained by extracting the figures directly from ArcGIS. This was extracted 27/8/14.

2) The tropical proportion variable was calculated by overlaying the Australian Bureau of Meteorology Australian Climatic Zones GIS shapefile[8] 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[9] 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.

Estimated Information

All figures provided for variables “DOEF0212 – Tropical Proportion” and “DOEF0214 – Bushfire Risk” are Estimated Information.

Justification for Estimated Information

The two variables of “DOEF0212 – Tropical Proportion” and “DOEF0214 – Bushfire Risk” are Estimated Information as they rely on the figure for “DOEF0204 – Total vegetation maintenance spans” which was also Estimated Information.

Methodology for Estimated Information

The figure for DOEF0204 was estimated using a statistical sampling methodology outlined in Basis of Preparation 3.7.2. Estimated information was 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.

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[8] http://www.bom.gov.au/climate/averages/climatology/gridded-data-info/gridded-climate-data.shtml
[9] http://www.dsdip.qld.gov.au/about-planning/spp-mapping-online-system.html

3.7.4 Maintenance cycles

The AER requires Energex to provide the following variables relating to maintenance cycles:

- **DOEF0206 – Average urban and CBD vegetation maintenance span cycle**
- **DOEF0207 – Average rural vegetation maintenance span cycle**

These variables are a part of Regulatory 3.7 – Operating Environment Factors.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 Methodology.
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 Assumptions and Approach.
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 Assumptions and Approach.

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

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

Methodology

Energex provided the DOEF0206 and DOEF0207 values using a weighted average of the Maintenance Span Cycles within urban/CBD and rural areas. The figures were based on the current and historical vegetation management contracts which stipulated the cycle lengths.

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

Approach

Energex uses a supplier managed program to determine maintenance span cycles. The suppliers work program is based on post codes and since they report on start and completion dates, the relevant cycle time for each maintenance span can be derived.

For each of the maintenance spans, Energex can classify into Urban/CBD and Rural using the ArcGIS shapefile for Urban/CBD (DOEF0202) and Rural (DOEF0201).

The average maintenance cycle is then derived as follows:

1) For each of the maintenance spans in a category (eg Urban/CBD) multiply the lengths of each maintenance spans by the relevant cycle time
2) Summate all of these maintenance span length x cycle time values in the category
3) Divide this summation by the total length of maintenance spans – this then provides the average maintenance span cycle for the category.

Estimated Information

Values for the average vegetation maintenance span cycle are Estimated Information because these are based on maintenance spans, which are also Estimated Information (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.

3.7.5 Defects

The AER requires Energex to provide the following variables relating to defects:

- **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 Regulatory 3.7 – Operating Environment Factors.

All figures reported for these variables are Estimated Information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 Approach
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 Approach
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 Approach
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 has Actual Information
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 Assumptions

Requirements (instructions and definitions)	Consistency with requirements
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 Assumptions

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

The figures provided for all variables are Estimated Information.

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

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.

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.

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 needs 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.

Estimated Information

Whilst the number of defects recorded by Energex is Actual Information, values provided are ultimately Estimated Information 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)

Justification for Estimated Information

These values are considered Estimated Information due to the reliance on estimated values for maintenance span from DOEF0202-4.

Basis for Estimated Information

Refer to the basis of preparation for DOEF0202, DOEF0203 and DOEF0204 for the methodology used to obtain Estimated Information for maintenance spans. Energex recorded 18 non conformances across it’s network in 2013/14. The figure is too low to appear in table 3.7 but it is 0.0000836992375. Energex is aware that it has more defects than this but these defects do not meet the definition provided by the AER as they are neither **recorded** or deemed a **non-compliance.**

3.7.6 No Standard vehicle access

The AER requires Energex to provide the following variables relating to standard vehicle access:

- **DOEF0213 – Standard vehicle access**

This variable is a part of Regulatory 3.7 – Operating Environment Factors and was provided, as an estimate for the 2013/4 year only.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in the figures are 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 Information Energex has estimated figures for standard vehicle access for the most recent Regulatory Year using the Energex GIS as the distribution route line length that does not fall within the road reserve.

Sources

Variable Code	Variable	Unit	Source
DOEF0213	Standard vehicle access	km	ArcGIS

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.

Assumptions

It is assumed that the route line length that does not fall within road reserve boundaries is an appropriate proxy for standard vehicle access, as this line cannot typically be accessed by standard vehicles.

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. This was subtracted from total route line length to find the distribution route Line Length that does not have Standard Vehicle Access.

Estimated Information

The figure stated for the standard vehicle access variable is an estimate, given that it is contingent on judgments and assumptions.

Justification for Estimated Information

The figures were estimated as Energex does not measure the distribution route line length with standard vehicle access.

Basis for Estimated Information

As stated in the methodology section, the estimate for this variable was based on calculating the route line length that does not fall 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.

3.7.7 Route Line length and density

The AER requires Energex to provide the following variables relating to route line length and density:

- **DOEF0301 – Route Line length (RIN Table 3.7.3)**
- **DOEF0101 - Customer density (RIN Table 3.7.1)**
- **DOEF0102 - Energy density (RIN Table 3.7.1)**
- **DOEF0103 Demand density (RIN Table 3.7.1)**

The AER requires Energex to provide information on Weather Stations

Table 3.7.4 contains information pertaining to Weather Staitons

These variables are a part of Regulatory 3.7 – Operating Environment Factors.

Information provided for DOEF0301 and DOEF0101, DOEF0102 and DOEF0103 figures reported are actual information.

Consistency with EB RIN Requirements

The table below sets out the relevant instructions and definitions provided by the AER, and the way in which the figures are 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 Approach
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 Assumptions
Customer density is the total number of customers divided by the route Line Length of the network.	Demonstrated in Approach
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 Energy And Demand Densities

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 the Weather Stations table such that all weather stations within its network will be included.	Rows have been added to the Weather Stations Template and appropriately coded
Energex must input the weather station number, post code, suburb/locality for all weather stations in its service area.	Refer to Weather Stations

All variables have been provided in accordance with the AER's instructions and definitions. All information provided for DOEF0301, DOEF0101, DOEF0102 and DOEF0103 is actuals.

Sources

Variable Code	Variable	Source
DOEF0301	Route Line length	ArcGIS

Methodology

Energex has extracted figures for the distribution route line length for 2014 from ArcGIS.

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.

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 numbers (DOPCN01, calculated in accordance with the Customer Numbers Basis of Preparation) for each year were divided by route line length.

Energy And Demand Densities

“DOEF0102 – Energy density” was calculated by dividing the total energy delivered to customers (DOPED01) by the total number of customers from RIN Table 3.4.2. The energy delivered was multiplied by 1000 to convert the figures to MWh.

“DOEF0103 – Demand density” was calculated by dividing the total non-coincident system annual maximum demand (DOPSD0201 from RIN Table 3.4.3.3) by the total number of customers (DOPCN01 from RIN Table 3.4.2.1) from RIN Table 3.4.2. The total non-coincident system annual maximum demand was multiplied by 1000 to convert the figures to MVA.

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.

	2013-14
DOEF0101 Customer Density	32.130
DOEF0301 Route Line Length	42,833

Weather Stations

Weather Station ID	Post code	Suburb	Materiality
040004 Amberley	4306	Amberley	Yes
040842 Brisbane Airport	4008	Brisbane Airport	Yes
040211 Archerfield Airport	4108	Archerfield	Yes
040717 Coolangatta	4225	Coolangatta	Yes
040861 Maroochydore	4564	Marcoola	Yes