Basis of Preparation

**Endeavour Energy
Response to AER Determination RIN**

Submission date: 30 May 2014

CONTENTS

Purpose

The Determination Regulatory Information Notice (RIN) requires Endeavour Energy to prepare a Basis of Preparation for all historic information in the Regulatory Templates which are the worksheets contained within the Microsoft Excel workbooks at Appendix A of the RIN. By this, the AER mean that for every historic variable in the Templates, Endeavour Energy must explain the basis upon which we prepared information to populate the input cells. The Basis of Preparation must be a separate document (or documents) that Endeavour Energy submits with its completed Templates. The AER will publish Endeavour Energy's Basis of Preparation along with the Templates.

This document is Endeavour Energy's Basis of Preparation in relation to the historic information contained within the Regulatory Templates required to be submitted to the AER by 31 May 2014.

AER's instructions

The AER requires the Basis of Preparation to follow a logical structure that enables auditors, assurance practitioners and the AER to clearly understand how Endeavour Energy has complied with the requirements of the RIN.

To do this, Endeavour Energy has structured its Basis of Preparation with a separate section to match each of the worksheets tabs where a Basis of Preparation is required.

The AER has set out what the minimum requirements for the Basis of Preparation are. This is detailed in Table 1 below:

1	Demonstrate how the information provided is consistent with the requirements of the Notice.
2	Explain the source from which Endeavour Energy obtained the information provided.
3	Explain the methodology Endeavour Energy applied to provide the required information, including any assumptions Endeavour Energy made.
4	In circumstances where Endeavour Energy cannot provide input for a Variable using Actual Information, and therefore must use an estimate, explain: (i) why an estimate was required, including why it was not possible for Endeavour Energy to use Actual Information; (ii) the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is Endeavour Energy's best estimate, given the information sought in the Notice.

Structure of this document

The document is structured as follows:

- We outline our general approach to developing our response to the RIN. We identify key systems used to provide data, note issues relating to data quality, and make comments on the reliability of the data for economic benchmarking purposes.

- We set out our response to worksheets in accordance with the AER's instructions. We note that Worksheets 1 and 3 and Tables 2.16, 7.1, 7.2 and 7.3 do not require a Basis of Preparation to be provided as they are either contain forecast information or require no input material.

General approach

In this section, we identify our general approach to collecting and preparing information.

Systems used to provide data

Where methodologies or assumptions were required to complete the files other than the mere application of the AER approved CAM to the general purpose financial statements Endeavour Energy has included commentary by way of the "note" function within Microsoft Excel to provide guidance to the AER.

Below is a listing of Endeavour Energy's systems that, to a greater or lesser extent, were directly related to or supported the development of the information contained in the RIN templates:

- Cognos – Business reporting system managing database information such as organisation policies and procedures;

- Ellipse – financial management system including: accounts payable; payroll; asset and equipment registers and financial reporting functions. The Ellipse system also caters for defect management (condition based) and also routine maintenance (planned). The equipment register is also linked to various other supporting systems such as field inspections and the Geographical Information System (GIS);

- TM1 – Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory accounts allocations. It is a cube based technology which allows rules to be created between cubes and within cubes;

- eFrams – Endeavour Energy uses this system in relation to IT Allocation Drivers. The system enables access to all telecommunication billing, inventory management/asset register and reporting;

- Remedy - Endeavour Energy uses this system in relation to IT Allocation Drivers. This is a BMC tool used by CGI for asset management, definitive software library, incident management and service request management;

- Autocad - Endeavour Energy uses this system in relation to Property Drivers. This is a program used for computer-aided design and drafting. The program is used to maintain Floor Plans which can be used to summarise occupancy by business unit;

- Banner – Endeavour Energy's customer database and billing system;

- Figtree – Worker's compensation claims management data base. This system is maintained separate (but linked at aggregate levels) to other systems to maintain confidentiality of data as required by legislation;

- Value Development Algorithm (VDA) – Endeavour Energy uses the Value Development Algorithm (VDA) for its high level asset renewal expenditure modelling. The model is populated with specific asset data in order to produce the replacement capital forecast. Data for each asset is allocated into asset categories, which represent major components that make up the network such as poles, transformers, conductor, cable, switchgear etc. Each asset type is assigned an asset life and a replacement cost. The quantity of assets installed on the network each financial year is also entered, thus generating an age profile of the network assets;

- Visual Risk – Endeavour Energy uses this Treasury Management System for improving the productivity of its treasury operations. Visual Risk provides functions such as capturing a facility drawdown; valuing an FX option; and facilitating back office administration and financial reporting. Specifically it was used to prepare the cost of funds schedule;

- System Fault Recording (SFR) – Endeavour Energy used this Oracle database system for all reliability reporting up until 2011/12. The data in this system is accessed using Cognos, with further analysis and processing of data being undertaken using Microsoft Office programs such as Access and Excel;

- SCADA - Endeavour Energy uses this system to monitor and control its network. Information from this system feeds into OMS (see below) to enable the calculation of reliability reporting information;

- Outage Management System - - Endeavour Energy uses this system to log outages and other events on its network. From 2012/13 onwards this system has been used as the source of data for all reliability reporting; and

- Contact Centre 6 – Endeavour Energy's call centre uses this system to run reports on historical call volume according to skill set (Call Type). The system is also used to assign agents to specific call taking groups based on call type.

Data quality issues

In previous consultations on the RIN, we have raised significant concerns with providing historical data in the form required by the AER. We will outline our concerns in relation to the detailed templates when we submit final audited data.

Approach to our obligations under the NEL

Our view of the NEL is that a DNSP is only obligated to provide information that is available, that is, data which has been historically collected in our systems. In cases, where that information cannot be provided in the form required by the AER from our systems, we would have a reasonable excuse under section 28(5) of the NEL not to comply with that element of the notice. We have strong doubts that a RIN can require a business to prepare information by way of estimate that cannot be reasonably derived from information currently held in its systems.

Our understanding of the term 'prepare' relates to a power the AER has to compel a DNSP to collect information in the form required by the AER for future periods (for example, by developing new systems) rather than to manipulate historical data in potentially inaccurate ways. We suggest that the AER should give more careful consideration to whether it has appropriately informed itself of the distinction under section 28D of the NEL between the ability of a RIN to require existing information to be provided and the ability to require information to be prepared, maintained and kept on a going forward basis.

Despite this Endeavour Energy has prepared and included the estimated data on an unaudited basis. We will address this issue in more detail in the Basis of Preparation for the final Audited Information.

Recognition by AER that 'best estimates' are not robust

The AER has acknowledged that if we are compelled to provide best estimates then there is potential for the data to lack robustness. Endeavour Energy will address the implications of using best estimates which are not robust in its Basis of Preparation to accompany the final Audited Information.

Worksheet 2.1 – Expenditure Summary & Reconciliation

2.1.1 Standard control services capex, 2.1.2 Standard control services opex by category, 2.1.3 Alternative control services capex & 2.1.4 Alternative control services opex

Compliance with requirements of the notice

The data presented in worksheet 2.1 is consistent with the requirements of the Reset RIN. In particular:

- Total opex and capex reported represents the expenditure split into Standard Control Services and Alternative Control Services in accordance with the definitions of these services and reconciles to the historical amounts reported in previous audited RINs.

- Total capex reported in tables 2.1.1 and 2.1.3 reconciles to the capex amounts reported in tables 2.2 to 2.10 and 4.1 to 4.4.

- The items included in the "Balancing item" row include those capex items not reported in tables 2.2 to 2.10 and 4.1 to 4.4. This includes expenditure associated with table 4.2 for "metering" which does not have its own discrete row in this table, capital contributions, infrastructure land purchases, system access/switching costs, essential spares, reliability capex, smart grid, power quality, environmental enhancement, asset relocations, direct capital overheads (not included in table 2.10 as these are not transferred from opex), a capitalised overhead adjustment and public lighting (which was double counted in tables 2.2 and 4.1).

- Total opex reported in tables 2.1.2 and 2.1.4 reconciles to the opex amounts reported in tables 2.2 to 2.10 and 4.1 to 4.4. The historical opex in tables 2.1.2 and 2.1.4 has been categorised and reported in a manner that is consistent with Endeavour Energy's approved Cost Allocation Method and most recent annual reporting RIN activities in the 2012/13 Regulatory Financial Statements.

- The items included in the "Balancing item" row include the duplicated costs captured under the "non-network" line in this table which would have been captured under the "Network and Corporate Overhead" categories.

- Total historical opex reported in tables 2.1.2 and 2.1.4 aligns to the approach adopted for the Benchmarking RIN and in particular Table 3.1.1. This approach was adopted as there has been a material change (over the course of the back cast time series) in Endeavour Energy's basis of preparation for its Regulatory Accounting Statements. As a consequence, the opex reported in tables 2.1.2 and 2.1.4 is not consistent with the Opex reported for the 2005/06 to 2010/11 financial years at a regulatory category level, but does reconcile to the total historical Opex as disclosed in the Regulatory Accounting Statements.

  Since Endeavour Energy completed the 2009 Distribution Determination RIN there have been a range of structural and operational changes across divisions as well as within the network functions.

  As a consequence, Endeavour Energy's activities and sub-activities that are used to identify actual costs by the opex categories contained in the annual RIN were reviewed and updated to ensure that the relationship between internal functions and reported costs is as robust and accurate as possible. This review identified several improvements to the segregation of the

standard control operating costs (which were unaffected by this review in aggregate) in the RIN operating cost categories as well as a change in the allocator for direct and indirect overhead costs from a percentage of direct labour to a percentage of direct operating expenditure.

Consequently, the main driver for Endeavour Energy's basis of preparation change in tables 2.1.2 and 2.1.4 is in the mix of costs being reported at a RIN category level compared to the historical RINs due to the re-allocation of activities and sub-activities to better reflect the reporting costs by the RIN categories. This is also relevant for overhead costs, due to changes in corporate structures which can be directly attributed to the Standard Control Service, but not to an individual RIN category.

Source of information

Capex

The following RIN tables were used to populate table 2.1.1:

- **Replacement expenditure** = 2.2 Repex;
- **Connections** = 2.5 Connections;
- **Augmentation expenditure** = 2.3 Augex;
- **Non-Network** = 2.6 Non Network;
- **Capitalised Network Overheads** = 2.10 Overheads;
- **Capitalised Corporate Overheads** = 2.10 Overheads; and
- **Balancing Item** = The reconciling difference to the historical RINs and the forecast expenditure, this includes expenditure associated with
  - table 4.2 for "metering" which does not have its own discrete row in this table;
  - public lighting which was included in table 2.2 for "repex" however it forms part of alternate control services hence it was subtracted within the balancing item as it was a duplicate;
  - the following items which were not asked to be included in any of the proceeding tables: reliability capex, infrastructure land purchases, essential spares, smart grid, power quality, environmental enhancement, asset relocations, direct capital overheads (that have not been included in the "capitalised network or corporate overheads" transferred from opex in 2.10), capital contributions and system access/switching costs.
  - Capitalised overheads – during the 2012/13 Annual RIN process the treatment of the allocation of capitalised overheads in capex and opex was reviewed, as a misalignment in the approach was identified. Historically the application of the CAM was applied to total opex and resulted in capitalised overheads being allocated across all the service classifications (ie SCS, ACS and unregulated). For capex, the capital overheads were allocated based on the proportion of direct capex, resulting in the overheads predominately being allocated to SCS and the remainder to public lighting (ACS). As noted in the Compliance with the Requirements section above, there was a change in the approach we adopted for the Benchmarking RIN (in particular Table 3.1.1) as there was a material change over the course of the back cast time series in Endeavour Energy's basis of preparation for its Regulatory Accounting Statements. As we have used the benchmarking RIN as the baseline for the opex schedule (and in particular table 2.10 for overheads), there is a mismatch in the historical overheads reported in the historical RINs and the Reset RIN and the benchmarking RIN data. This mismatch had been corrected from the annual reporting period of 2012/13 onwards so they now both align.
  - Other –Other variances are considered immaterial. Breakdown of balancing item attached below.

		Previous period	Current regulatory period			
			Actual/ estimate ($000s nominal)			
		2008/09	2009/10	2010/11	2011/12	2012/13
	balancing item	90,914,851	84,804,990	91,905,735	118,454,809	103,523,106
	Metering	4,163,789	3,108,415	3,393,943	4,161,682	3,062,625
	Cap Cons	56,032,000	44,127,000	50,798,302	62,378,465	67,218,974
	Infrastructure Land	3,531,527	7,962,732	1,098,402	490,798	24,760
	Switching	4,505,108	4,549,873	5,032,463	5,342,401	6,601,698
	Essential Spares	1,454,735	1,664,221	151,370	29,240	2,142,136
	Reliability	9,115,079	9,647,364	9,625,341	11,232,209	10,972,122
	Smart Grid	-	-	262,728	6,569,201	7,300,615
	Power Quality	141,671	110,998	40,945	155,301	297,776
	Environmental Enhancement	558,763	264,326	152,950	132,057	55,631
	Asset Relocation	1,874,776	1,469,753	527,101	2,062,498	1,276,318
	Direct Capitalised Overheads	6,128,458	9,004,643	14,003,085	14,908,507	14,628,766
	Capitalised Overheads Adjustment	7,483,135	9,482,497	7,510,082	15,765,261	1,286
	Public Lighting (double counted in tables 2.2 and 4.1)	(4,058,771)	(3,920,396)	(4,334,371)	(5,526,971)	(5,710,195)
	Other (balancing item of other items)	(15,419)	(2,666,435)	3,643,395	754,160	(4,349,408)
	Total	90,914,851	84,804,990	91,905,735	118,454,809	103,523,106
	Variance	-	-	-	-	-

The following RIN tables were used to populate table 2.1.3:

- **Connections** = 2.5 Connections;
- **Metering** = 4.2 Metering;
- **Public Lighting** = 4.1 Public Lighting;
- **Fee & Quoted** = 4.3 Fee-based services and 4.4 Quoted services; and
- **Balancing Item** = The reconciling difference to the historical RINs and the forecast expenditure – this is an immaterial variance.

Opex

The following RIN tables were used to populate table 2.1.2:

- **Vegetation management** = 2.7 Vegetation management;
- **Maintenance** = 2.8 Maintenance;
- **Emergency Response** = 2.9 Emergency Response;
- **Non-Network** = 2.6 Non Network;
- **Network Overheads** = 2.10 Overheads;
- **Corporate Overheads** = 2.10 Overheads; and
- **Balancing Item** = The reconciling difference to the historical RINs and the forecast expenditure, this includes expenditure associated with the duplicated costs captured under the "non-network" line in this table which would have been captured under the "Network and Corporate Overhead" categories.

The following RIN tables were used to populate table 2.1.4:

- **Connections** = 2.5 Connections;
- **Metering** = 4.2 Metering;
- **Public Lighting** = 4.1 Public Lighting;
- **Fee & Quoted** = 4.3 Fee-based services and 4.4 Quoted services; and
- **Balancing Item** = The reconciling difference to the historical RINs and the forecast expenditure – this is an immaterial variance.

Methodology and assumptions

Table	Methodology	Assumptions
2.1.1, 2.1.2, 2.1.3 & 2.1.4	1/ Extract expenditure from the Reset RIN templates listed in the source of information above.	Nil
	2/ Reconcile table totals to historical RINs and the forecast expenditure and explain any variances.	Nil

Use of estimated information

All historical information provided for the tables in section 2.1 consist of actual information (no estimated information required).

Reliability of information

All historical information provided represents Information extracted from Endeavour Energy's reporting systems and has been reconciled to reported figures in previous audited RINs. As a result, the information contained in tables 2.1.1, 2.1.2, 2.1.3 and 2.1.4 is considered to be reliable. Future forecast information is considered to be estimated.

2.1.5 Dual function assets capex

Compliance with requirements of the notice

Endeavour Energy does not have any dual function assets and hence does not need to complete this table in the Excel workbook.

2.1.6 Dual function assets opex by category

Compliance with requirements of the notice

Endeavour Energy does not have any dual function assets and hence does not need to complete this table in the Excel workbook.

Worksheet 2.2 – Repex

2.2.1 Cost metrics by asset category and 2.2.2 Descriptor metrics

Compliance with requirements of the notice

Past and future expenditure and replacement quantities were estimated and provided to comply with the requirements of tables 2.2.1 and 2.2.2.

Source of information

Data was sourced as follows:

- Age profiles derived from Table 5.2.1
- Finance historical expenditure data
- Finance current year (2013/14) data
- 2014/15 SAMP Data
- VDA data
- Ellipse

Methodology and assumptions

- Historical replacement quantities were calculated by applying a renewal component percentage to age profiles developed for table 5.2.1. The renewal component percentage was calculated based on past expenditure of SARP projects to the total SAMP on a year by year basis.
- Past and future expenditure was categorised into the major categories of the Repex input sheet. The category totals were proportioned into subcategories. Proportioning was weighted by quantity and past replacement costs from VDA. Substations Miscellaneous and Establishments totals were provided as totals due to difficulties allocating these costs. Capacitor banks costs were included in the substation miscellaneous total.
- Future replacement quantities were estimated by dividing future expenditure by a new calculated replacement cost. New calculated replacement costs were calculated by dividing the proportioned past replacement costs by the past replacement quantities.
- Exceptions made for service mains and capacitor banks where actual numbers were used.
- Failure rates were obtained from work orders out of Ellipse. A failure may not have resulted in a replacement.
- Failures for distribution switchgear lumped into one line whereas replacement quantities were split into switchgear types.
- Quantities for Urban, Rural Short and Rural Long assets were estimated by applying percentages to total volumes and estimated replacement quantities. Percentages were calculated from feeder lengths and their classifications.
- Total MVA replaced was estimated by multiplying replacement quantities and the median rating of the transformer category.
- Total MVA disposed was assumed to be equal to the Total MVA replaced.
- Historical replacement quantities were calculated by applying a renewal component

Use of estimated information

Historical expenditure were proportioned into required categories and used to calculate estimates. Actuals could not be used due to high level reporting and lack of discrete data in Ellipse.

Reliability of information

- Source of calculations was based on historical finance data. Estimates and proportioning were based on this data.

- Reliability of failure data is poor and it was not possible to calculate this for most of the asset categories due to the difficulty of obtaining required data.
- Areas in the tables were data was unavailable were filled with zeroes as per instructions.

Worksheet 2.3 – Augex project data

2.3.1 Augex asset data – Subtransmission substations, switching stations and zone substations

Compliance with requirements of the notice

The information provided on this work sheet is consistent with the requirements of this Notice. Where possible actual costs and values have been used, in areas where individual work orders would need to be obtained and analysed estimates have been made as outlined below.

Source of information

Project information has been obtained from the following sources:

- Network Investment Options Reports
- Project Definitions
- Transmission line designs
- Post Commissioning Review Reports
- Ellipse

Methodology and assumptions

The methodology used to complete table 2.3.1 is outlined below:
- From the Finance group a list of all projects that had money spent from the 2008/2009 financial year to Feb 2014 was obtained. The remaining costs for the 2013/14 year were estimated by the Finance group and have been incorporated into the data tables for Table 2.3.1.
- From these projects, projects with minimal spend in the above period were removed
- For each of the remaining projects:
    - Actual costs for each of the projects by organisational unit broken into the categories "Labour, Materials, Contractors & Consultants, IT&T Expenses and Other Expenses" for each financial year from 2006/2007 to Feb 2014 was obtained.
    - Actual costs for each of the projects separated into Labour, Materials etc. was obtained for the period 2000/01 to 2005/06. These costs were not available on an organisational unit basis and hence were separated using averages from the 2006/07 to Feb 2014 costs.
    - The organisational units were divided into six distinct categories, "Subs, Mains, Subs Civil, Distribution, Land and Projects" based on the organisational unit. The Projects category was required as often work for project is costed to the "Capital Projects" or "Major Projects" group which encompasses substations and mains works, it also includes outsourced work.
    - The number of transformers, switchgear (i.e. hv and lv circuit breakers, e.g. for a 132/11kV zone substation the number of 132kV and 11kV circuit breakers installed) and capacitor banks installed under the project and the actual costs for these plant items was obtained from Ellipse.
    - From the initial Project Definition a ratio of "Transmission Mains costs", "Transmission mains civil costs", "Substation civil costs" and "Substation costs" to the total costs of the project was obtained. Where one of these classes of costs was not available an estimate was made based on other projects of a similar nature. These ratios were used to divide the costs of the "Projects" category between table 2.3.1 and 2.3.2.
    - The costs for "Civil Works", "Other Direct", "Non-Related Party Contracts" were calculated by apportioning actual costs based on the ratios calculated for the "Projects" type above between the table 2.3.1 and 2.3.2.

- For a limited number of projects the costs had to be subtracted from the "Non-Related Party Contracts" column and added to "Other Plant Costs" to give positive costs for the "Other Plant Costs". In these scenarios it is likely that the other plant was actually purchased under contracts and hence is in the "Contractors & Consultants" costs.
- We note that the instructions provided in Appendix E section 7.2(l) of the notice require total expenditure for transformers, switchgear, capacitors and other plant items to include only the procurement costs of the equipment. This must not include installation costs. The template for table 2.3.1 however includes a formula that includes installation labour costs and other direct expenditure. These costs are therefore included in the Total Expenditure column.

The costs have been indexed based on the multipliers below:

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
CPI	0.015	0.045	0.044	0.030	0.028	0.023	0.027	0.035	0.0233
Index	1.452	1.390	1.331	1.293	1.258	1.229	1.197	1.156	1.130

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
CPI	0.0435	0.0182	0.0285	0.0339	0.018	0.025	0.025	0.025	0.025
Index	1.083	1.063	1.034	1	0.983	0.993	0.983	0.993	0.983

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CPI	0.025	0.025	0.025	0.025	0.025	0.025
Index	0.993	0.983	0.993	0.983	0.993	0.983

It should be noted that the majority of projects have a substations and a mains component. The total project costs are the sum of the substations and mains component. If the costs from these tables are to be used to determine a $/MVA for the costs a new zone substation then the costs from the substations component (Table 2.3.1) and the costs from the mains component (Table 2.3.2) have to be summated.

It should be noted that the following projects have been initiated predominantly due to a need to connect new customers (these include non-material projects as well):

Project Number	Project Number	Project Number	Project Number	Project Number
PR029	PR223	PR291	PR424	PR509
PR070	PR238	PR292	PR425	PR546
PR110	PR241	PR302	PR427	PR559
PR128	PR244	PR306	PR429	PR572
PR156	PR254	PR329	PR430	PR596
PR165	PR255	PR338	PR432	PR602
PR168	PR257	PR339	PR436	PR605
PR182	PR260	PR341	PR437	PR656
PR183	PR261	PR342	PR438	PR659
PR184	PR279	PR386	PR444	PR674
PR190	PR280	PR408	PR499	

Use of estimated information

Other Plant Item Expenditure

This value was calculated by subtracting total material costs (apportioned to the substations component) minus the costs for transformers, switchgear and capacitors. In some projects some costs from the "Contracts" component have been moved to the "Other Plant" costs as the plant may have been procured under "Contracts". This estimation method was required as it would have been too time consuming to go through individual project work orders to obtain the material costs for each "Other Plant Item".

Installation (Labour) – Volume

For the periods 2006/07 to Feb 2014 volume of labour was readily available from the financing systems. For periods outside this the volume of labour has been estimated based on the average $/hour of the period 2006/07 to Feb 2014. This labour volume is the labour for the whole project it includes volume for work outside of the installation of plant. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine labour attributable to installation and labour that isn't.

Installation (Labour) – Expenditure

This value was calculated by adding costs from the "Labour" category. The breakdown of the "Projects" component has been estimated based on the initial Project Definition. This labour expenditure is the labour expenditure for the whole project (except for civil works) it includes volume for work outside of the installation of plant. The labour expenditure for 2014/15 and beyond have been adjusted for increases in labour costs above standard inflation rate. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine labour attributable to installation and labour that isn't.

Other Expenditure - Civil Works

This value was calculated by adding costs from the "Subs civil" category and "Projects" category. The breakdown of the "Projects" component has been estimated based on the initial Project Definition. This estimation method was required as it would have been too time consuming to go through individual project work orders to obtain the material costs for each "Other Plant Item".

Other Expenditure – Other Direct

This value was calculated by adding costs from the "Other Expenses" group, the breakdown of the "Projects" component has been estimated based on the initial Project Definition. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine parts attributable to table 2.3.1 and 2.3.2.

All non-related party contracts – Total

This value was calculated by adding costs from the "Contactors and Consultants" group, the breakdown of the "Projects" component has been estimated based on the initial Project Definition. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine parts attributable to table 2.3.1 and 2.3.2.

Reliability of information

The actual total costs (total costs from Table 2.3.1 and Table 2.3.2 summated for the project) for the projects are reliable as it is straight from Ellipse. The cost breakdowns between table 2.3.1 and 2.3.2

are estimates; these estimates are then applied to variables outlined above. The apportioning of costs associated incurred by the "Projects" group to the substation/mains component is based on initial estimates in the Project Definitions. The actual proportions may have changed depending on actual designs and unforseen issues.

2.3.2 Augex asset data – Subtransmission lines

Compliance with requirements of the notice

The information provided on this work sheet is consistent with the requirements of this Notice. Where possible actual costs and values have been used, in areas where individual work orders would need to be obtained and analysed estimates have been made as outlined below.

Source of information

Project information has been obtained from the following sources:
- Network Investment Options Reports
- Project Definitions
- Transmission line designs
- Post Commissioning Review Reports
- Ellipse
- GIS

Methodology and assumptions

The methodology used to complete table 2.3.2 is outlined below:
- From the Finance group a list of all projects that had money spent from the 2008/2009 financial year to Feb 2014 was obtained. The remaining costs for the 2013/14 year were estimated by the Finance group and have been incorporated into the data tables for Table 2.3.2.
- From these projects, projects with minimal spend in the above period were removed
- For each of the remaining projects:
  - o Actual costs for each of the projects by organisational unit broken into the categories "Labour, Materials, Contractors & Consultants, IT&T Expenses and Other Expenses" for each financial year from 2006/2007 to Feb 2014 was obtained.
  - o Actual costs for each of the projects separated into Labour, Materials etc. was obtained for the period 2000/01 to 2005/06. These costs were not available on an organisational unit basis and hence were separated using averages from the 2006/07 to Feb 2014 costs.
  - o The organisational units were divided into six distinct categories, "Subs, Mains, Subs Civil, Distribution, Land and Projects" based on the organisational unit. The Projects category was required as often work for project is costed to the "Capital Projects" or "Major Projects" group which encompasses substations and mains works, it also includes outsourced work.
  - o The number of poles/towers added, upgraded was obtained from the relevant transmission line design drawings. Where a pole was replaced it was counted as upgraded, where a new pole was installed it was counted as pole added.
  - o The transmission line lengths were obtained from project definitions, transmission line drawings and the GIS system.
  - o From the initial Project Definition a ratio of "Transmission Mains costs", "Transmission mains civil costs", "Substation civil costs" and "Substation costs" to the total costs of the project was obtained. Where one of these classes of costs was not available an estimate was made based on other projects of a similar nature. These ratios were used to divide the costs of the "Projects" category between table 2.3.1 and 2.3.2.

- o The costs for "Civil Works", "Other Direct", "Non-Related Party Contracts" were calculated by apportioning actual costs based on the ratios calculated for the "Projects" type above between the table 2.3.1 and 2.3.2.
- o For a limited number of projects the costs had to be subtracted from the "Non-Related Party Contracts" column and added to "Other Plant Costs" to give positive costs for the "Other Plant Costs". In these scenarios it is likely that the other plant was actually purchased under contracts and hence is in the "Contractors & Consultants" costs.
- o Where existing lines being operated originally at a lower voltage have been reused at a higher voltage without any reconductoring they have still been included in "Circuit km upgraded"

The costs have been indexed based on the multipliers below:

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
CPI	0.015	0.045	0.044	0.030	0.028	0.023	0.027	0.035	0.0233
Index	1.452	1.390	1.331	1.293	1.258	1.229	1.197	1.156	1.130

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
CPI	0.0435	0.0182	0.0285	0.0339	0.018	0.025	0.025	0.025	0.025
Index	1.083	1.063	1.034	1	0.983	0.993	0.983	0.993	0.983

	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
CPI	0.025	0.025	0.025	0.025	0.025	0.025
Index	0.993	0.983	0.993	0.983	0.993	0.983

It should be noted that the majority of projects have a substations and a mains component. The total project cost is the sum of the substations and mains component. If the costs from these tables are to be used to determine a $/MVA for the costs a new zone substation then the costs from the substations component (Table 2.3.1) and the costs from the mains component (Table 2.3.2) have to be summated.

It should be noted that the following projects have been initiated predominantly due to a need to connect new customers (these include non-material projects as well):

Project Number	Project Number	Project Number	Project Number
PR029	PR190	PR339	PR499
PR070	PR244	PR342	PR521
PR110	PR255	PR425	PR596
PR165	PR261	PR427	PR656
PR182	PR280	PR429	PR674
PR183	PR292	PR444	

Specifically in relation to Schedule 2 instruction 7.3(p) for Table 2.3.2, Endeavour Energy does not record easements as a separate project line item. Endeavour Energy does not acquire land for sub-transmission lines, its policy is to only acquire easements. Land and Easements are itemised as separate expenses within a project.

Use of estimated information

Poles/Towers – Expenditure

A standard rate has been assumed for the pole costs based on the most common pole type used which has then been multiplied by the number of poles added and upgraded. This estimation method was required as it would have been too time consuming to go through individual project work orders to obtain the material costs for each pole.

Overhead Lines/Underground Cables – Expenditure

A per km rate for material for the standard types of conductors/cables was obtained from the Transmission Mains group. The type of conductor/cable was determined from transmission line drawings/network characteristics document. The standard material rate was applied to the transmission line to calculate the material costs. This estimation method was required as it would have been too time consuming to go through individual project work orders to obtain the material costs for each conductor/cable.

Other Plant Item – Expenditure

This value was calculated by subtracting total material costs (apportioned to the mains component) minus the costs for poles, conductors and cables. In some projects some costs from the "Contracts" component have been moved to the "Other Plant" costs as the plant may have been procured under "Contracts". This estimation method was required as it would have been too time consuming to go through individual project work orders to obtain the material costs for each "Other Plant Item".

Installation (Labour) – Volume

For the periods 2006/07 to Feb 2014 volume of labour was readily available from the financing systems. For periods outside this the volume of labour has been estimated based on the average $/hour of the period 2006/07 to Feb 2014. This labour volume is the labour for the whole project it includes volume for work outside of the installation of plant. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine labour attributable to installation and labour that isn't.

Installation (Labour) – Expenditure

This value was calculated by adding costs from the "Labour" category. The breakdown of the "Projects" component has been estimated based on the initial Project Definition. This labour expenditure is the labour expenditure for the whole project (except for civil works) it includes volume for work outside of the installation of plant. The labour expenditure for 2014/15 and beyond have been adjusted for increases in labour costs above standard inflation rate. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine labour attributable to installation and labour that isn't.

Other Expenditure - Civil Works

This value was calculated by adding costs from the "Subs civil" category and "Projects" category. The breakdown of the "Projects" component has been estimated based on the initial Project Definition. This estimation method was required as it would have been too time consuming to go through individual project work orders to obtain the material costs for each "Other Plant Item".

Other Expenditure – Other Direct

This value was calculated by adding costs from the "Other Expenses" group, the breakdown of the "Projects" component has been estimated based on the initial Project Definition. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine parts attributable to table 2.3.1 and 2.3.2.

All non-related party contracts – Total

This value was calculated by adding costs from the "Contactors and Consultants" group, the breakdown of the "Projects" component has been estimated based on the initial Project Definition. This estimation method was required as it would have been too time consuming to go through individual project work orders to determine parts attributable to table 2.3.1 and 2.3.2.

Reliability of information

The actual total costs (total costs from Table 2.3.1 and Table 2.3.2 summated for the project) for the projects are reliable as it is straight from Ellipse. The cost breakdowns between table 2.3.1 and 2.3.2 are estimates; these estimates are then applied to variables outlined above. The apportioning of costs associated incurred by the "Projects" group to the substation/mains component is based on initial estimates in the Project Definitions. The actual proportions may have changed depending on actual designs and unforseen issues.

2.3.3 Augex asset data – HV/LV feeders and distribution substations

Compliance with requirements of the notice

This section is intended to demonstrate how the information provided is consistent with the requirements of this Notice, specifically those set out in the relevant parts of Section 7.4, 7.5 and 7.6.

Specifically, Table 2.3.3 displays the following over the requested time periods:

- The quantum of assets **added** in the HV Feeder category (both overhead and underground)

- The quantum of assets **added** in the LV Feeder category (both overhead and underground)

- The quantum of assets **added** in the Distribution Substation category (Indoor, ground mounted and pole mounted)

- The quantum of assets **upgraded** in the HV Feeder category (both overhead and underground)

- The quantum of assets **upgraded** in the LV Feeder category (both overhead and underground)

- The quantum of assets **upgraded** in the Distribution Substation category (Indoor, ground mounted and pole mounted)

- The total costs of these activities on an annual basis from 2008/09 to 2018/19

Source of information

Project information for the HV feeder category was gathered in a similar manner to that for Tables 2.3.1 and 2.3.2, that is, costs were obtained from financial data contained in the Ellipse system associated for the list of relevant projects that were completed (or are to be completed) within the requested time frames. This includes costs for those items that were contracted out. The asset length data for HV feeders was estimated from the planning estimates in the Distribution Works Program using length factors (typical augmentation costs per km for overhead and underground work). Those Network Connections works that are initiated to allow individual connections to the network are not included in this data.

For Distribution Substations and LV Feeders, the annual expenditure for each of these categories was obtained from the Ellipse database. The categories are:

LV001 – Overloaded distribution substation uprates: This captures the upgrading of distribution substation transformers (pole mount, ground mount and indoor) based on maximum demand readings.

LV002 – Quality of supply reactive projects: This captures the costs of responding to customer complaints such as low volts, frequent loss of supply due LV overloads and overvoltage issues. The rectification work may include installing new pole or ground mounted substations and new or the upgrading of LV overhead or underground feeders.

LV003 – Quality of supply for planned projects: This is reserved for when transformers are not able to be upgraded in LV001 due to capacity constraints and a new substation at another location needs to be established. The scope of work may include installing new pole mount or ground mount subs and new LV overhead or underground feeders.

LV004 – Low voltage system augmentation: This is used to augment mainly LV overhead feeders, for example upgrading undersized LV conductors due to overloading or voltage drop issues.

The physical information for each of the above categories was gathered by the Regional Services section in the North, Central and Southern Regions based on their best available data.

Table 2.3.3 does not contain expenditure and quantities on network augmented due to customer connection.

Methodology and assumptions

The financial details and data on length of asset installed gathered on a project by project basis for HV feeders, together with the project description in the Distribution Works Program, allowed a division into new construction added or upgraded to be completed. This allowed categorisation into the "Units Added" and "Units Upgraded" tables in 2.3.3.1. The assembly of costs for HV feeders in each category was brought together in Table 2.3.3.2. Note that, for HV feeders, no "non material projects" have been identified. This is explained by highlighting that the vast majority of distribution feeder works exceed the $500,000 threshold for inclusion as material projects and moreover those smaller items can be thought of as works directly linked to the other, larger, items. Typically, non material projects amount to some 3-4% of the whole.

For distribution transformers and LV feeders, each Region provided an estimate for the physical quantities for the number of distribution transformers (pole, ground and indoor), LV overhead and underground cables added or upgraded.

The allocation of costs to each activity (in $000's) was based on the application of typical historical ratios for the split of expenditure across these categories as follows::

(i)	LV feeder augmentations - overhead lines:	$D+(B+C)*0.1$
(ii)	LV feeder augmentations - underground cables:	$(B+C)*0.4$
(iii)	Distribution substation augmentations - pole mounted ($000's) :	$0.54*(A+(B+C)*0.4)$
(iv)	Distribution substation augmentations - ground mounted ($000's):	$0.44*(A+(B+C)*0.4)$
(v)	Distribution substation augmentations - indoor ($000's):	$0.02*(A+(B+C)*0.4)$

And, LV feeder non-material projects: $T – [(i)+(ii)+(iii)+(iv)+(v)]$

where:

$A=LV001, B=LV002, C=LV003, D=LV004, T=A+B+C+D$

Use of estimated information

Growth predictions for HV feeders is based on forward projections in the Distribution Works Program, however, forward expenditure in the Distribution Substation and LV Feeder augmentation categories has been assumed to continue at a steady rate. The estimation of lengths of upgraded or new HV distribution feeders was based on typical $/km for underground and overhead augmentation works. Apart from the assumptions mentioned above, no other estimated information has been used in this section.

Reliability of information

The base origin of the data presented in Table 2.3.3 is resident in Endeavour Energy's Ellipse system which provides both financial tracking and project lists. Detailed analysis of the project lists within the Distribution Works Program were also utilised to provide more detailed understanding of proportional costs within the high voltage feeders area.

The data is therefore considered to be reliable.

2.3.4 Augex asset data – total expenditure

Compliance with requirements of the notice

The information is obtained from the available data in Endeavour Energy.

Source of information

The financial information was sourced from the Ellipse database.

Methodology and assumptions

The expenditure for the following rows was derived as follows:

- Subtransmission Substations, Switching Stations, Zone Substations: From table 2.3.1
- Subtransmission Lines: From table 2.3.2
- HV Feeders: From table 2.3.3.2
- HV Feeders - Land Purchases and Easements: No land purchase cost captured as most HV feeders are on State land or on road reserves.
- Distribution Substations: From table 2.3.3.2
- Distribution Substations - Land Purchases and Easements: Cost is estimated only for any added ground substations that require land easement. Not required for pole mount or indoor substation.
- LV Feeders: From table 2.3.3.2
- LV Feeders - Land Purchases and Easements: No land purchase cost captured as most LV feeders are on State land or on road reserves.
- Other Assets; Nil

The sum of group augmentation expenditures in Table 2.3.4 does not reconcile directly with Tables 2.3.1, 2.3.2 and 2.3.3. This is because Tables 2.3.1 and 2.3.2 are expressed in real $12/13 and Table 2.3.4 requires expenditure as incurred in each year. In addition Tables 2.3.1 and 2.3.2 required costs in relation to total project expenditure which includes expenditure outside of the years specified in Table 2.3.4 prior to 2008/09.

Use of estimated information

A land purchase and easement cost is paid only for newly added ground mount substation. It is very time consuming to search the individual cost of these easements, thus an estimate cost of $12,000(includes land purchase, survey and legal cost) was used for each ground mount substation added as shown in Table 2.3.3.2. An estimated cost was provided by the Network Property section.

Reliability of information

The information is based on input from other tables.

Worksheet 2.4 – Augex model

2.4.1 Augex model inputs - asset status – subtransmission lines

Compliance with requirements of the notice

This section is intended to demonstrate how the information provided is consistent with the requirements of this Notice, specifically those set out in the relevant parts of Section 8.2 (a) to (f).

Specifically, Table 2.4.1 displays the following for the 2012/13 and 2018/19 years:

- Each subtransmission line identified by a unique ID number and its originating and terminating points

- Each subtransmission line rating

- Subtransmission line maximum demand weather corrected at 50 per cent probability of exceedance

- The expected growth per feeder in the 2012/13 to 2018/19 period

Source of information

The list of subtransmission feeders in Table 2.4.1 was obtained from Endeavour Energy's Network Characteristics Database as of 30 June 2013. This database was also the source of route line lengths and line ratings.

For each of the years 2008/09 and 2012/13 line load data has been provided. This was obtained from the Network Load History (NLH) database, which accesses Endeavour Energy's network operating data acquired directly from Endeavour's SCADA system. In a small number of cases in the far western part of the network (i.e. lines from the Mt Piper/Ilford Hall/Kandos area), maximum demand data on lines is not always available and data sourced from the Transmission Network Planning Review (TNPR) reports in the relevant years has been used. Where lines are removed or new lines constructed in the time period covered by Table 2.4.1, this is noted in the table data. Note also that network configurations can change significantly over the time period studied and make the matching of lines to a "before" and "after" situation difficult in some cases. However, all lines are matched in the most appropriate way. Where lines are generally on standby (i.e. normally open), this is also noted. In two cases associated with supplies ex-Springhill TS, the load to major customer supplies at BOC (98B) was not available in 2008/09 and the load to Figtree on Feeder 7098 in 2012/13.

Line ratings were obtained from Endeavour Energy's Network Characteristics Database (current as of 30 June 2013). These are the line ratings used in augmentation planning and are calculated in accordance with standard industry methodologies (see standards references below). In situations where only the normal cyclic rating of a line is recorded in the database, the emergency rating of that particular line was assumed equal to the normal cyclic rating. Note that where lines are comprised of different elements (eg a mix of conductor sizes), the overall line rating is that of the section with the lowest rating. The basis of ratings is presently as follows:

- Overhead lines – Mains Design Instruction 42, which in turn refers to ESAA publication D(b)5:1988 (Current rating of bare overhead line conductors) as the design basis.

- Underground cables - Mains Design Instruction 46, which uses IEC 60287 as the design basis.

The Network Characteristics Database is progressively being brought up to full alignment with the standards regimes mentioned above.

Methodology and assumptions

Maximum Demand:

Generally, only 'b' phase current data for lines is gathered and made available in the NLH database and this was obtained for the relevant lines for the 2008/2009 and 2012/2013 years. The actual maximum demand (in MVA) was then calculated assuming that the loads on lines are balanced and the lines are operated at the rated voltage.

In order to determine an estimated 50% PoE demand for each subtransmission feeder listed in Table 2.4.1, each feeder was grouped with its Transmission Substation as indicated in the Network Characteristics Database. The power factor and the ratio of actual maximum MVA to weather corrected maximum MVA at 50% PoE for each Transmission Substation was then determined for 2008/2009 and 2012/2013 using data in the TNPR. This ratio (and the power factor) were then applied to the actual maximum demand for each subtransmission feeder to determine weather corrected maximum demand (in both MVA and MW) at 50% PoE. The methodology is further explained below.

To calculate the 50% PoE value for each feeder, the following ratio calculated at all Transmission Substations (TS) was applied to the actual maximum demand of subtransmission feeders to determine an estimated weather corrected maximum demand (in MVA) at 50% PoE.

$$Ratio = \frac{Actual\ Maximum\ Demand\ (MVA)at\ the\ TS}{Weather\ corrected\ maximum\ demand\ at\ 50\%\ PoE\ (MVA)at\ the\ TS}$$

In order to determine the weather corrected maximum demand of a line in MW, the power factor of the applicable TS was multiplied by the weather corrected maximum demand of the line in MVA which is obtained as stated above.

These line loads represent the demand used for forward planning purposes, and exclude abnormal operating conditions.

No calculations in relation to the use of a 10% PoE forecast have been carried out.

Forecast Growth in Feeder Demand

The feeder demand from 2012/13 to 2018/19 has been estimated using the growth rates at each relevant substation in accordance with the following approach:

- For each line that has a single end point, the growth rate for that end point over the period 2012/13 to 2018/19 has been applied to the load data.
- For lines that are connected in a meshed fashion, i.e. there are at least two end points serviced from the line, the growth rate at the source has been applied to the load data.

The application of this approach ensures that the growth in feeder load reasonably reflects that in the demand forecast.

Note that where a line supplies a dedicated HV major customer, no growth in the feeder load has been applied.

Forecast maximum demand growth rates are those reflected in Endeavour Energy's published forecasts and are therefore the most realistic expectation of demand at the time of responding to the

regulatory information notice, and are the forecast maximum demands used in developing proposed capital or operating expenditure.

This forecast maximum demand growth rate reflects the approach typically used for planning purposes.

Use of estimated information

As mentioned above, a small amount of modelled load data has been used for the Western area. This is not considered to be a significant issues due to the relatively small loads encountered in this area.

The attribution of "Urban", "Long Rural" and "Short Rural" classifications to subtransmission feeders is difficult due to the high mix of load types, and their relative magnitudes, at each location. The classifications entered are based on local understanding of the regions supplied and not strictly in accordance with any calculation methodology.

Reliability of information

The base origin of the data presented is resident in Endeavour Energy's NLH database. This database contains both metered and SCADA data sourced via direct measurement instruments attached to the network. Given the scale of the penetration of measurement, the network database is extremely powerful. As such, a strong foundation for the understanding of network constraints is available. This is supplemented by a planning approach that looks to ensure that the data used in the preparation of augmentation proposals is valid, for example that no abnormal operating conditions result in misleading data. A typical verification method would be to compare NLH data with modelled data to ensure that the measured data has a close degree of conformity to the expected data.

2.4.2 Augex model inputs - asset status – high voltage feeders

Compliance with requirements of the notice

This section is intended to demonstrate how the information provided is consistent with the requirements of this Notice, specifically those set out in the relevant parts of Section 8.3 (a) to (h).

Specifically, Table 2.4.2 displays the following:

- a row for each high voltage feeder on Endeavour Energy's network together with the required details

- each high voltage feeder identified by a unique ID number

- each high voltage feeder rating based upon the main trunk segment exiting the substation

- maximum demand measured at the feeder exit from its associated substation

Source of information

The list of distribution feeders in Table 2.4.2 was obtained from Endeavour Energy's Distribution Network Status Report (DSR) as of 7 December 2012. This database was also the source for route line lengths and line ratings. The DSR in turn sources its data from the Network Load History (NLH) database for feeder loadings and GIS for feeder lengths. The Network Load History (NLH) database accesses Endeavour Energy's network operating data directly from Endeavour's SCADA system, in this case from instrumentation connected to feeder circuit breaker panels.

In most cases, only 'b' phase current data for lines is available for use as an input to the DSR and these were obtained for the relevant feeders for the 2008/2009 and 2012/2013 years. The actual maximum demand (in MVA) for each feeder was then calculated assuming that the loads on lines are balanced and the lines are operated at the rated voltage. The raw load data is filtered within the DSR preparation process to ensure that abnormal operating conditions are eliminated. This filtering includes a calculation that compares observed maximums on all feeders to ensure that no "outlying" result is included in the feeder maximum loads. In a small number of cases, load data has not been available and these instances have been noted in Table 2.4.2.

Feeder ratings are based on Endeavour Energy's Mains Design Instruction No 11 (Underground distribution cables – continuous current ratings). The first section of each feeder from its source substation has been attributed a rating in accordance with its type and size and, for underground cables, includes a de-rating factor to allow for the close grouping of cables at the exit points from the substation. This rating is in accordance with the principles outlined in the above Design Instruction. A copy of this document can be made available if required.

Methodology and assumptions

Feeder loads are sourced from NLH data and are filtered to exclude abnormal operating conditions and normally represent the demand used for forward planning purposes. It is considered that this approach gives a better representation of the loads that the feeders are expected to encounter in a true operational sense than the 50% PoE demands requested in the RIN template. However, 50% PoE figures have been provided as requested.

To determine an estimated 50% PoE demand for each distribution feeder listed in Table 2.4.2, each feeder was grouped with its source Zone Substation. The ratio of actual maximum MVA to weather corrected maximum MVA at 50% PoE for each Zone Substation was then determined for 2008/2009 and 2012/2013 using data in the Transmission Network Planning Review (TNPR). This ratio (and the associated source power factor) were then applied to the actual maximum demand for each

distribution feeder to determine weather corrected maximum demand (in both MVA and MW) at 50% PoE. This was carried out as follows:

The following ratio calculated at all Zone Substations (ZS) was applied to the actual maximum demand of distribution feeders to determine an estimated weather corrected maximum demand (in MVA) at 50% PoE.

$$Ratio = \frac{Actual\ Maximum\ Demand\ (MVA) at\ the\ ZS}{Weather\ corrected\ maximum\ demand\ at\ 50\%\ PoE\ (MVA) at\ the\ ZS}$$

In order to determine the weather corrected maximum demand of a line in MW, the power factor of the applicable ZS was multiplied by the weather corrected maximum demand of the line in MVA.

In relation to the average growth in feeder demand over the 2012/13 to 2018/19 period, feeder loads were augmented in this period in accordance with the forecast for their source Zone Substation. The application of this approach ensures that the growth in feeder load reasonably reflects that in the demand forecast. Due to the fact that growth appears in variable blocks on to new substations, growth figures across the requested period can be distorted in these cases. For example, a substation that has zero load in 2011/12 can have significant load in 2018/19. In the cases where load appears in 2012/13 or 2013/14, the average calculation is carried out over this period in order to present a more sensible and realistic indication of growth.

Note that where a line supplies a dedicated HV major customer, no growth in the feeder load has been applied.

Forecast maximum demand growth rates are those reflected in Endeavour Energy's published forecasts and are therefore the most realistic expectation of demand at the time of responding to the regulatory information notice, and are the forecast maximum demands used in developing proposed capital or operating expenditure.

No calculations in relation to the use of a 10% PoE forecast have been carried out.

Use of estimated information

No other estimated information has been used in this section.

Reliability of information

The base origin of the data presented is resident in Endeavour Energy's Network Load History (NLH) database. This database contains both metered and SCADA data sourced via direct measurement instruments attached to the network. Given the scale of the penetration of measurement, the network database is extremely powerful. As such, a strong foundation for the understanding of network constraints at main distribution feeder level is available. This is supplemented by a planning approach that looks to ensure that the data used in the preparation of augmentation proposals is valid, for example that no abnormal operating conditions result in misleading data

2.4.3 Augex model inputs - asset status – subtransmission substations, subtransmission switching stations and zone substations

Compliance with requirements of the notice

This section is intended to demonstrate how the information provided is consistent with the requirements of this Notice, specifically those set out in the relevant parts of Section 8.4 (a) to (h).

Specifically, Table 2.4.3 displays the following:

- a row for each subtransmission substation, subtransmission switching station and zone substation on Endeavour Energy's network together with the required details
- number and rating of transformers at each location
- maximum demand weather corrected at 50% probability of exceedance at each location
- average per annum growth in maximum demand from 2012/13 to 2018/19

Source of information

The list of substations in Table 2.4.3 was obtained from Endeavour Energy's Network Characteristics Database as of 30 June 2013. This database was also the source for equipment ratings.

For each of the years 2008/09 and 2012/13 substation load data has been provided. This was obtained from the Network Load History (NLH) database, which accesses Endeavour Energy's network operating data acquired directly from Endeavour's SCADA system.

Transformer ratings were obtained from Endeavour Energy's Network Characteristics Database (current as of 30 June 2013). These are the ratings used in augmentation planning and are calculated in accordance with standard industry methodologies (see standards references below). Only the normal cyclic rating of a transformer is currently available and this is therefore assumed to be equal to the emergency rating of that particular unit. Transformer ratings are presently based on Australian Standard AS2374.7 (recently updated to AS60076.7). However, the data gathering and calculations necessary to implement the application of emergency ratings has not been completed to date, and no data up to 2012/13 is available at this time.

A new Endeavour Energy standard document (GNV 1105) is currently under preparation to consolidate the transformer rating requirements and efforts are being made to address the overall emergency rating issue such that the Network Characteristics Database can progressively be brought up to full alignment with the standards regimes mentioned above.

Methodology and assumptions

50% PoE demands for each substation location are directly available from Endeavour Energy's published forecast data, which includes historic actual demands at all substation locations.

The average per annum load growth at each location over the period 2012/13 to 2018/19 was evaluated directly from the Endeavour Energy 2014/23 published summer forecast, with a simple averaging of the demand growth over the relevant period being calculated. In carrying out this calculation, summer load data has been used as this represents the most onerous condition on transformer plant.

Forecast maximum demand growth rates are those reflected in Endeavour Energy's published forecasts and are therefore the most realistic expectation of demand at the time of responding to the

regulatory information notice, and are the forecast maximum demands used in developing plans for augmentation capital expenditure.

It should be noted that, in all cases, the Substation "normal cyclic" has been assumed to be equal to the Transformer "normal cyclic" as there are no known locations where plant other than the transformers (eg bushings, cables etc.) limits the delivery capacity of the transformers.

No calculations in relation to the use of a 10% PoE forecast have been carried out.

Use of estimated information

No other estimated information has been used in this section.

Reliability of information

The base origin of the transformer data presented is resident in Endeavour Energy's Network Characteristics Database. The data is therefore considered to be sound, however an expanded understanding of emergency ratings would be advantageous in assessing future actions in relation to transformer augmentations.

The forecast data is derived fundamentally from both metered and SCADA data sourced via direct measurement instruments attached to the network. Given the scale of the penetration of measurements, this network database is extremely powerful. As such, a strong foundation for the building of forecasting methodologies is available. More detail on the robustness of forecasting principles is included in regulatory templates 5.3 and 5.4.

2.4.4 Augex model inputs - asset status – distribution substations

Compliance with requirements of the notice

The information provided on this work sheet is consistent with the requirements of this Notice and is based on the available information in Endeavour Energy.

Source of information

The maximum demand readings and the rated kVA of the distribution transformers were sourced from the Ellipse database.

Methodology and assumptions

The maximum demand readings were done on yearly basis for distribution transformers greater than 100kVA but some transformer rated at ≤63kVA are read on need basis. A total of 22,917 readings were recorded in the Eliipse database for readings in 2012/2013 against a total of 29,721 distribution transformers. Similarly, for 2008/2009 it was 21,246 readings against a total of 27,005. As required by AER, the transformers without maximum demand readings were estimated.

The name plate ratings of the transformer were used for the calculation as it is not Endeavour's practice to use cyclic rating for distribution transformers. Only since 2013/2014, Endeavour began using cyclic rating based on SMI 116 for uprating the transformer based on the results of continuous monitoring.

The transformers in the distribution substations were categorised as pole sub or pad sub (ground mount) in locations fed by urban, rural short or rural long feeders with the following ratings:
Pad subs <= 500kVA – ground mount transformers 500,400*,300*,315,300*,250*,150*,100*kVA
Pad subs > 500kVA - ground mount transformers 750*,800*,1000,1500kVA
Pole sub < =63kVA – pole mount transformers 63,58*,50,30*,25,23*,20*,16,15*,10*,7.5*,5*,3*,2*kVA
Pole sub <=400kVA:- pole mount transformers 75*,100,110*,150*,160*,200,250*,300*,315,400kVA
- *non- standard transformers*

Distribution network information system (DINIS) a network analysis software package is used as a planning tool to determine feeder loads, busbar voltages, voltage drops and short circuit currents of the transmission, sub transmission and high voltage distribution networks.
Only the raw maximum demand reading from Ellipse database is used yearly for the above analysis, while transformers without reads are estimated. Any planned connections are also included in the analysis.
No weather corrected at 50 percent or 10 percent probability of exceedance is used for the maximum demand of distribution transformers.

The utilisation percentage was calculated based on the number of transformers in the utilisation category against the total number of transformers for that regulatory period.
An example for 2012-13 follows:

Utilisation band 60 – 80%

Distribution subs – Urban Pad subs <= 500kVA	5.67%
Number of transformers from this category that is within 60-80% utilisation	1,686
Total number of transformers in 2012-13 `	29,721
Percentage utilisation within 60-80% = 1,686/29,721	= 5.67%

Use of estimated information

The maximum demand for transformers that do not have maximum demand readings for that period is estimated based on the location of the subs that are fed either by either urban or rural feeder.
The maximum demand is estimated as follows: (based on Branch procedure NCP1110)
Urban subs: 80% of nameplate
Rural: 70% of nameplate

To estimate a forward program for replacement due to overload, an average per annum growth rate of 0.22% per annum over the 2012-13 to 2018-19 period was applied. This estimate was based on a study undertaken by Primary Systems Branch on load growth patterns at distribution substation level.

Reliability of information

The information is based on actual maximum demand readings taken by Endeavour Energy staff. There is a possibility of reading errors, faulty meters and high maximum demand due to temporary load transfer (this is evident in a small percentage of subs recording greater than 150% loading which needs to be verified).

2.4.5 Augex model inputs – network segment data

Compliance with requirements of the notice

Endeavour Energy has created the following segments:

Network segment ID	Network segment title	AER segment group
1	132kV summer peaking	1
2	132kV winter peaking	1
3	66kV summer peaking	1
4	66kV winter peaking	1
5	33kV summer peaking	1
6	33kV winter peaking	1
7	TS, summer 2 tx	2
8	TS, summer 3 tx	2
9	TS, summer 4 tx	2
10	TS, summer 8 tx	2
11	TS, winter 1 tx	2
12	TS, winter 2 tx	2
13	TS, winter 3 tx	2
14	1 tx summer	3
15	2 tx summer	3
16	3 tx summer	3
17	1 tx winter	3
18	2 tx winter	3
19	3 tx winter	3
20	Urban Summer	5
21	Urban Winter	5
22	Short rural Summer	6
23	Short rural Winter	6
24	Long rural Summer	7
25	Long rural Winter	7
26	Pad subs <= 500kV	9
27	Pad subs > 500kVA	9
28	Pole sub <= 63kV	9
29	Pole Sub <= 400kVA	9
30	Pad subs <= 500kVA	10
31	Pad subs > 500kVA	10
32	Pole sub < =63kVA	10
33	Pole sub <=400kVA	10
34	Pad subs <= 500kVA	11
35	Pad subs > 500kVA	11
36	Pole sub < =63kVA	11
37	Pole sub <=400kVA	11

Description of Network Segments

AER Segment Group 1 - The transmission lines have been broken up by voltages and whether the feeder is summer or winter peaking. This categorisation was used as the $/MVA vary between the voltages and the ratings of the lines differ between summer and winter.

AER Segment Group 2 - The transmission substations have been categorised by the number of transformers installed and whether they are winter or summer peaking. This categorisation was used as the capacity factor varies based on the number of transformers installed .

AER Segment Group 3 - The zone substations have been categorised by the number of transformers installed and whether they are winter or summer peaking. This categorisation was used as the capacity factor varies based on the number of transformers installed.

AER Segment Group 5, 6 and 7 - The high voltage feeders have been categorised on whether they are summer peaking or winter peaking. These are the 11kV and 22kV voltage feeders supplying distribution substations from zone substations. 22kV feeders have been grouped with 11kV feeders due to relatively small number of 22kV feeders.

AER Segment Group 9, 10 and 11 - The distribution substations have been categorised on size. This is due to the fact the $/MVA and capacity factor changes depending on the size of the substations.

Note: Endeavour Energy does not have any CBD feeders or distribution substations.

Source of information

The sources of information are:
- Project definitions
- Project definition cost estimates
- Actual costs from Finance (Ellipse)

Methodology and assumptions

Unit Costs and Capacity Factors

AER Segment Group 1 – The unit costs for transmission lines have been determined by analysing a sample of past major projects which had line works included in them (irrespective of if they had sub transmission feeder constraints or not). The capacity factor for transmission lines was determined by analysing only projects which addressed capacity constrained sub transmission feeders. The source of information was the project definitions created at the time of project initiation and the project cost estimates at the time of project initiation, and actual costs where available. Actual costs are available for completed projects, projects that are incomplete will have estimated costs. The process followed is outlined below:

- From the project definition and the network needs report determine the capacity added e.g. a 15MVA line augmented to 20MVA – capacity added = 20MVA – 15MVA = 5MVA, capacity factor = Capacity Added/15 = 1.33. A new line built with a rating of 50MVA, the line that had constraints on it had a rating of 36MVA, capacity added = 50MVA, capacity factor = capacity added/36 = 1.38. An average of all projects capacity factors for that category was then calculated and is used in Table 2.4.5.
- The unit costs were obtained by dividing the total actual project costs (where available) by the capacity added. (costs were indexed to 12/13 dollars). An average of all project unit costs for that category was then calculated and is used in Table 2.4.5.

AER Segment Group 2 – The unit costs for sub transmission stations have been determined by analysing a sample of past and current major projects which includes the augmentation of a sub transmission substation (irrespective of if they had sub transmission substation constraints or not). The capacity factor for sub transmission stations was determined by analysing only projects which addressed capacity constrained sub transmission stations. The source of information was the project definitions created at the time of project initiation. The project cost are actuals incurred in the past and forward estimate cost indexed to 2012/13 real dollar. In categories where there were no past projects the costs of another category have been used.

AER Segment Group 3 – The unit costs for zone substations have been determined by analysing a sample of past and current major projects which includes the augmentation of a zone substation (irrespective of if they had zone substation constraints or not). The capacity factor for zone substations was determined by analysing only projects which addressed capacity constrained zone substations. The source of information was the project definitions created at the time of project initiation. The project cost are actual costs incurred in the past and forward estimate cost indexed to 2012/13 real dollar. In categories where there were no past projects the costs of another category have been used.

AER Segment Group 5,6 and 7 – The unit costs and capacity factors for distribution lines was determined by analysing high voltage distribution feeder works items created in the last four years.

For each category of feeders the number of projects that created a new feeder (i.e. connection to a zone substation circuit breaker) was identified. From this the capacity added was calculated by multiplying the number of feeders added by the standard capacity of a feeder (300A). From the project description the number of overloaded feeders (at the zone substation circuit breaker) it was addressing was also noted. The capacity factor was obtained by dividing the number of new feeders created by the number of overloaded feeders addressed.

The costs for all other projects during this period (excluding fault level exceeded items), e.g. augment overloaded conductor, establish cross feeder tie etc., and the costs for projects that created new feeders were summated to give a total cost for all projects. The $/MVA was then calculated by dividing these summated costs by the capacity added. The project costs are actual cost where projects are completed. Estimate costs are used for projects which are in progress.

AER Segment Group 9, 10 and 11 - The unit costs for distribution substations have been obtained from actual costs from sample projects. The capacity factor is calculated by the change in size of transformers for the categories.

The unit costs used for the various categories compare relatively to the Optimised Depreciated Replacement Costs Valuation of the Endeavour Energy network completed in 2010.

Utilisation Thresholds

AER Segment Group 1 – The utilisation threshold for 33kV feeders general was calculated by analysing past projects which addressed constraints on sub transmission feeders. The forecast load on the feeder three years ahead of the time of project initiation identified in the project's investment options report was divided by the rating of the feeder at the time of project initiation to determine the utilisation threshold. The load three years ahead was used as in general projects are initiated three years before the need for the project. In general the loads on the feeder in project investment options reports only have feeder loads under n-1 conditions, to get the feeder load under n conditions the n-1 load was multiplied by 2.

For the 66kV lines and 132kV lines due to the limited number of projects a utilisation threshold mean of 60% which is based on the 120% of n-1 capacity limit placed by the previous licence conditions and utilisation threshold standard deviation of sqrt(60) has been used.

AER Segment Group 2 – The utilisation threshold mean of sub transmission substations in general was calculated by analysing past projects which addressed constraints on sub transmission substation. The forecast load on the substation three years ahead of the time of project initiation identified in the project's investment options report was divided by the rating of the substation at the time of project initiation to determine the utilisation threshold. An average utilisation and standard deviation was calculated from these projects. The load three years ahead was used as in general projects are initiated three years before the need for the project.

Where there was a limited number of projects for analysis a utilisation threshold of 50% has been used as prescribed in the previous license conditions (100% of n-1 capacity).

AER Segment Group 3 – The utilisation threshold mean of zone substations in general was calculated by analysing past projects which addressed constraints on zone substations. The forecast load on the zone substation three years ahead of the time of project initiation identified in the project's investment options report was divided by the rating of the zone substation at the time of project initiation to determine the utilisation threshold. An average utilisation and standard deviation was calculated from these projects. The load three years ahead was used as in general projects are initiated three years before the need for the project.

AER Segment Group 5,6 and 7 – The utilisation threshold was determined by averaging the utilisation threshold of high voltage distribution feeder works items created in the last four years. This was calculated by dividing the load on the feeder at the time of project creation (obtained from the project reason for works description) by the standard 300A feeder rating.

AER Segment Group 9, 10 and 11 – The utilisation threshold mean is based on an internal standard specifying utilisation thresholds of 100% for padmount substations and 110% for pole mount substations. The threshold standard deviation is the square root of the mean.

With reference to utilisation thresholds as a trigger for augmentation and the relationship to internal/and or external planning criteria:

- For historical projects the NSW Licence conditions specified thresholds for utilisation in relation to different levels of the network. This included an 80% utilisation threshold on forecast demand for 11kV and 22kV urban feeders, a 20% threshold on load above thermal capacity under N-1 conditions for zone substations and sub-transmission substations. For underground sub-transmission lines forecast demand forecast demand was not to exceed thermal capacity under N-1, as such for a two feeder system maximum allowable utilisation would have been 50%. Although these conditions apply to specific locations in the network, they would have an impact on segment level utilisation as an outcome.

- For expenditure in the next regulatory period, some of this relates to completion of projects in progress that were approved under the previous Licence Conditions and utilisation for these locations are affected in the same way as historical projects.
  The majority of new capacity driven projects in the next regulatory period for Endeavour Energy are for greenfield development including projects that are required to establish the initial 'N' supply in a new development precinct. For constraints under N-1, Endeavour Energy a cost benefit analysis would apply.

Use of estimated information

- The $/MVA for sub transmission lines, sub transmission/zone substations and hv feeders are based on estimated project costs.
- The $/MVA for distribution substations is based on actual costs for replacement/augmentation for projects over the last 4 years..

Reliability of information

The actual costs for the sub transmission lines, sub transmission/zone substations and hv feeders projects have been used where available to calculate $/MVA. Only incomplete projects in the samples had estimated costs applied. This should ensure a high level of reliability.

Segments have been chosen to avoid double counting of capacities added. Methodology of how capacity and costs were allocated to various segments from projects is described in the Methodology and Assumptions above. The data will be audited independently as part of the quality assurance process for the RIN tables.

2.4.6 Capex and net capacity added by segment group

Compliance with requirements of the notice

This section is intended to demonstrate how the information provided is consistent with the requirements of this Notice, specifically those set out in the relevant parts of Section 8.7 (a) to (c).

Specifically, Table 2.4.6 displays the following over the requested time periods:

- The type of net capacity added (i.e. Types 1, 2 and 3 for each of the categories of subtransmission and zone substations and Types 1 and 2 for subtransmission lines)

- The costs for each line item in the table and which costs are attributed to "customer initiated" or "NSP initiated" capacity related augmentations.

Source of information

Project information has been gathered in a similar manner as that for Tables 2.3.1 and 2.3.2, that is, costs were obtained from financial data associated with the list of relevant projects that were completed (or are to be completed) within the requested time frames. Capacities added were obtained from project related information such as Network Investment Options Reports, Project Definitions, Transmission line designs and Post Commissioning Review Reports. Indexation data to allow the rationalising of the financial data into 10/14/15 dollars was obtained from Endeavour Energy's Finance section.

Equipment ratings were obtained from Endeavour Energy's Network Characteristics Database as of 30 June 2013.

Future expenditure profiles were obtained as follows:
- For Subtransmission lines, Subtransmission substations and subtransmission switching stations and Zone substations - from the data presented in Endeavour Energy's latest version of the Strategic Asset management Plan (SAMP)
- For HV Feeders – growth to 2018/19 is based on projections in the 2013/14 issue of the Distribution Works Program. Growth in Connections Work expenditure is taken from the SCI and is based on projections of historic expenditure trends.
- For distribution substations (including downstream LV network) – an equivalent growth rate to that developed for HV feeders has been used in forward projections

Methodology and assumptions

Financial data was gathered on a project by project basis as well as an overall activity basis in relation to high voltage distribution feeder works, distribution transformers and the associated low voltage works. In the case where individual projects are readily visible, that is for major projects and distribution feeder works, including those works associated with major projects, these projects were individually categorised into "NSP initiated" or "customer initiated" and the relevant costs and capacities entered into Table 2.4.6. The categorisation into "urban", "short rural" and "long rural" was also carried out on a project by project basis for major subtransmission and zone substation projects. In the case of distribution feeder works, the ratio of customer/NSP initiated works was determined by the ratio of feeder works carried out in association with new customer associated zone substation works and feeder works contained in the annual Distribution Works Program. For other connection works, that is those works that are directly associated with the connection of customers (and Endeavour funded), the split into OH or UG for the connection works group was assumed to be equivalent to the ratio for other HV works. For future connection works, a notional

per meter installation cost was assumed to determine future lengths and the split into OH and UG was assumed to be the average split over the current regulatory period for HV works.

For the distribution transformer (including downstream LV network) category, the customer initiation proportion was provided using customer connection data that indicated a proportion of 90/10 customer/NSP ratio in this class. The urban/short rural/long rural split was determined for high voltage feeder works by assuming a ratio split equal to the ratio of urban/short rural/long rural feeders within Endeavour Energy. The urban/short rural/long rural split for distribution transformer (including downstream LV network) was determined by assessing the proportion of transformers (from a capacity perspective) that were installed on either urban or short rural feeders. The distribution transformer costing calculations were developed by using typical estimated unit costs per transformer scaled by the transformer numbers involved. The transformer uprate costs used were $70k per pole substation, $150k per padmount substation and $200k per indoor substation.

The date assigned to the capacity added columns was the date when the project is completed, eg a project commenced in 2010/11 but not completed till 2014/15 would have the capacity added in 2014/15.

The 2013/14 costs for high voltage feeder works have been pro-rated from accrued cost data up to March 2014.

"Unmodelled augmentation" costs are considered to be, in this case, those distribution works that involve the replacement of fault rating exceeded conductors. These needs typically arise as a result of increasing fault levels as a result of other network augmentations. Where no specific data on this expenditure is available (in this case 2006/07, 2007/08 and 2015/16 to 20018/19) a proportion of total high voltage feeder works equal to the average for the years 2008/09 to 2014/15 has been used.

Note that Endeavour Energy has no CBD feeders or transformers and these cells have been entered as "0".

Use of estimated information

Apart from the assumptions mentioned above, no other estimated information has been used in this section.

Reliability of information

The base origin of the data presented in Table 2.4.6 is resident in Endeavour Energy's Ellipse system which provides both financial tracking and project lists. Detailed analysis of the project lists within the Distribution Works Program were also utilised to provide more detailed understanding of proportional costs within the high voltage feeders area.

The data is therefore considered to be reliable.

Worksheet 2.5 – Connections

2.5.1 Connections metrics

Compliance with requirements of the notice

The data provided in this section seeks to address the requirements of Appendix E, Clause 10 and Appendix F of the Regulatory Information Notice. Where the data is readily available, actual data has been used to complete template 2.5.1. In other instances, data has been derived from actual data and for the remainder, data has been estimated/calculated based on a number of known parameters.

Source of information

Data has been obtained from a number of internal sources as outlined below;

- Finance and Compliance Division – Ellipse (general ledger, fixed asset register) and Banner (customer data).
- People and Service Division – customer complaint information.
- Network Operations Division – GSL data
- Network Connections Branch – Customer connection, NOSW information and SAMP 10 year forecast of lots serviced.

Methodology and assumptions

The data held by the Company did not in all cases align with the data breakout as required by the reporting template. As a result it was necessary to cross match and supplement base data with other actual data available from other Company systems. Where data was not readily available from historical records, required template information was derived/calculated from actual data and current information obtained from analysis and review of available information.

The data used in the completion of the template were as follows;

- Actual customer numbers by class and forward estimate
- Fixed asset register and general ledger for financial details by class
- Customer Application Management System (CAMS) for validation of transformer numbers and size
- Asset Valuation Sheet (AVS) used for the estimation of UG and OH circuit lengths
- Actual GSL data, numbers and payments. It should be noted that for the forecast period Endeavour Energy target zero GSL breaches.
- Actual customer complaint numbers. It should be noted that for the forecast period, Endeavour Energy target zero customer complaints.
- March 2014 Notification of Service Work (NOSW) Endeavour Energy form number FPJ4503, sample used to determine connection types, customer proportions and connection methodology. This data was used to assist in proportioning the connections between residential and subdivision and as a subset the embedded generator connections that occur to an existing network connection.
- Developed estimation ratios for each connection class and type to fill template requirements
- Financial Report actuals and forward estimates
- Strategic Asset Management Plan (SAMP) 10 year financial data
- SAMP 10 year Lot forecast

Use of estimated information

Endeavour Energy has used estimated information for the following elements of the template;

- The split of OH and UG connections for each of the Connection Subcategories in Template 2.5.1
- The circuit km added to the network for each of the Connection Subcategories in Template 2.5.1
- Forward estimates beyond the 2012/2013 reporting period for which actual data is not available.

- An estimate was required for the above reporting elements because actual data was not available from Company records.

- The basis for the estimates is outlined below;

  a) Split of OH and UG connections – This estimation was applied to connections in the Residential, Commercial/Industrial and Subdivision categories of template 2.5.1. Whilst historical customer data was maintained by the Company in the three major reporting categories it did not naturally break into overhead and underground connections. The Embedded Generation category also needed to be addressed for connection type. A sample of NOSW forms for March 2014 was analysed to determine the connection methodology and type of connection being made. From this analysis, assumptions were developed and applied to the actual data provided in the customer numbers document. These numbers were then included in the reporting template. The process applied used the year on year customer number change, split the numbers into the required categories and then applied the proportion of the OH and UG connection split.

  b) Circuit km added to the network – The Company did not have available the data that would allow the ready completion of the template for these categories for HV and LV connection. Financial data was available from the financial reports, for both overhead and underground connections, however, route length was not available. To derive these lengths, the current Asset Valuation Sheet (AVS) was used to develop typical costs for standard construction types per km for both HV and LV overhead and underground installations. Indexation is not applied to these costs. The financial data from the AVS was then used to derive route lengths for each connection type. The 2012-13 AVS data was used to calculate the preceding year's conductor length data.

  c) To prepare forward estimates of the various descriptor metrics required for the Connection Subcategories, the forward financial estimates provided by Finance and Compliance Division have been used as a basis for determining activity levels. The financial data was used to develop a relational factor for each year. This factor when applied to the base descriptor metrics contained in the 2012/13 actual activity levels has produced relevant data for each of the reporting periods. It has been assumed that the forward financial estimates reflect the agreed incremental activity levels.

  d) Cost per Lot has been obtained by calculation using the SAMP financial data and the lot numbers included in the SAMP 10 year lot forecast.

Reliability of information

The core data used in the approximation was Company data that had a high level of integrity. The estimation process outlined in (a), (b) and (c) is technically sound and when applied to the core data has produced acceptable results.

The forward estimate data has been calculated using forward financial data as a basis for determining the means of estimating the forward descriptor metrics. The estimation method is sound and verifiable.

Information Not Included in the Template

The following information has not been included in the template;

- **Residential – Mean Days to Connect Residential Customer with LV single phase connection**

The Company does not maintain records of the length of time negotiated or accomplished by a Level 2 Accredited Service Provider in completing the Connection Service arranged with their individual customers. The Company has no involvement in the allocation or monitoring of work completion by Level 2 Accredited Service Providers.

- **Embedded Generation – Distribution Substations and Circuit Augmentation**

Small scale embedded generation systems connected to the network are required to first be a retail customer and have an installation which is already connected to the network. As a result load related matters are dealt with during the load connection process. There are no available Company records that indicate that any distribution substations have been added to the network or circuit augmentation required to facilitate the connection of a small scale embedded generator.

The numbers included in the templates for embedded generator connections are not considered as additional new customers connecting to the network. They therefore are not included in the connection data by Connection Subcategory – Residential, Industrial / Commercial or Subdivision. The data provided in the Actual customer numbers by class document, has a line item for the increase in the number of solar connections. This number was used as the basis to apply the connection ratio to determine the number of OH and UG connections.

The numbers quoted are stand alone based on the connection requirements outlined in paragraph 1 of this reporting item.

2.5.2 Cost metrics by connection classification

Compliance with requirements of the notice

The data provided in this section is based on the core data used to respond to the requirements for template 2.5.1. The data for this template is a restatement of the data provided in the previous template with a focus in this instance on the connection methodology defined in Appendix F.

Source of information

Data has been obtained from a number of internal sources as outlined below;

- Finance and Compliance Division – Ellipse (general ledger, fixed asset register) and Banner (customer data).
- People and Service Division – customer complaint information.
- Network Operations Division – GSL data
- Network Connections Branch – Customer connection and NOSW information.

The data included in template 2.5.1 using the above sources has been used to complete the relevant parts of template 2.5.2. For example, the number of simple residential connections included in table 2.5.2 for 2012-13 is the sum of the OH and UG connections from line number 1 and 2 of the residential category in table 2.5.1.

Methodology and assumptions

The data held by the Company did not align with the data breakout as required by the reporting template. As a result it was necessary to cross match and supplement base data with other actual data available from other Company systems. Where data was not readily available from historical records, required template information was derived from actual data and current information obtained from analysis and review of available information.

The assumptions used in the completion of this template are as follows;

- **Residential** – All residential connections are simple connections to existing LV infrastructure allowing connection of up to 100 amps single phase or 63 amps three phase.
- **Commercial / Industrial** – All commercial / industrial connections are complex, customers are connected at LV and there is some upstream network works required.
- **Subdivision –** All subdivision connections are complex with HV extension to the network to allow connections to be completed at LV to developed infrastructure.
- **Embedded Generation –** All embedded generation less than 5kW single phase is a simple connection made to an existing network connection for the residential load at the connected premises.

Use of estimated information

The completion of this template has been based on information contained in template 2.5.1. The data used are actual values based on the source data provided by groups listed under the heading "Source of Information".

The forward estimates contained in template 2.5.1 have also been used to develop the forward data required in this template. The basis for calculation of the base data is outlined in 2.5.1 - **Use of estimated information** part (c) and (d)

Reliability of information

The data used to complete the historical data in the template is based on actual data and has a high level of integrity and reliability.

The forward estimate data has been calculated using forward financial data as a basis for determining the means of estimating the forward descriptor metrics. The estimation method is sound and verifiable.

Information Not Included in the Template

- **Residential** – The rows for Complex Connection LV and Complex Connection HV, have not been allocated any values for the period.
- **Commercial / Industrial** – The rows for Simple Connection, Complex Connection HV (Customer Connected at LV, upstream asset works), Complex Connection HV (Customer connected at HV) and Complex Connection Sub – Transmission, have not been allocated any values for the period.
- **Subdivision** – The rows for Complex Connection, and Complex Connection HV (with upstream asset works), have not been allocated any values for the period.
- **Embedded Generation** – The rows for Complex Connection HV (Small Capacity) and Complex Connection HV (Large Capacity), have not been allocated any values for the period.

Worksheet 2.6 – Non-network

2.6.1 Non-network expenditure

Service Subcategory

IT and Communications

Compliance with requirements of the notice

The data presented in the tables contained in table 2.6.1 is consistent with the definition of Non-network IT and Communications Expenditure per the RIN definitions contained in Appendix F. In particular:

• The data presented in table 2.6.1 reflects IT & Communications opex and capex expenditure. The data is reported by Asset Category in accordance with the RIN definitions contained in Appendix F.

• The non-network IT & Communications opex and capex listed in table 2.6.1 is all non-network expenditure directly attributable to IT and communications assets including replacement, installation, operation, maintenance, licensing, and leasing costs but excluding all costs associated with SCADA and Network Control Expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices.

• The opex data presented in tables 2.6.1 represents the total operating expenditure including labour, overtime, plant, materials, maintenance, other contractors, professional services and other operating expenses pertaining to all non-network IT & Communications expenditure. Further, Maintenance includes Computer Expenses (expense element 3600), Telephone-Land Line Lse/Purch/Call Chrgs (expense element 3610), Telephone-Employee Rembrs Call Chrg/Rent (expense element 3615) and Telephone-Mobile Phone Lse/Purch/Call Chr (3616).

• The Capex data presented in tables 2.6.1 represents the total operating expenditure including labour, overtime, plant, materials, maintenance, other contractors, professional services and other operating expenses pertaining to all non-network IT & Communications expenditure.

• The non-network IT & Communications opex and capex in table 2.6.1 is directly attributable to this expenditure category in this regulatory template. For the purposes of table 2.6.1 we have reported all capex and/or opex as *Direct Costs* as required, irrespective of them also being classified as *Corporate Overheads* or *Network Overheads* or other capex or opex categories.

Source of information

The information used to populate the tables contained in section 2.6.1 was extracted directly from TM1. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes.

Set out in the table below are the specific cubes used to obtain the required information for the tables in section 2.6.1, along with a description in relation to the use of the cube by Endeavour Energy:

Table	TM1 Cube	Description
2.6.1	PNL cube	The PNL cube contains General ledger information sourced from Ellipse (GL system) based on Endeavour's chart of accounts.
2.6.1	Project Reporting cube	The Project Reporting cube contains General ledger information sourced from SQL server database which is extracted nightly from Ellipse (GL System).

In addition, information from Work orders was utilised in section 2.6.1 which is extracted directly from MS Access query against the SQL server database which is extracted nightly from Ellipse. Query is run on parameters specified to extract the data.

Methodology and Assumptions

The following table sets out the methodology applied to calculate the required data for the IT and Communications sections in table 2.6.1:

Table	Methodology	Assumptions
2.6.1 (opex)	1. Extract IT & Communications Opex data from the TM1 PNL cube for Information Communication & Technology Division. 2. Extract IT & Communications Maintenance data from the TM1 PNL cube for all Divisions (excluding Information Communication & Technology Division). 3. Extract Work order data from MS Access query, parameters org unit I350 ICT Contracts & Commercial, Maintenance expense elements. Balance to extract of TM1 PNL cube for org unit I350, Maintenance category. 4. Extract data from TM1 cube Project Reporting to identify Retail Sale Labour Costs included in Information Communication & Technology Division Labour category. 5. Asset category allocation of above data based on RIN definitions. 6. Reconcile Asset Category to TM1 PNL cube data extracted above.	• Table 2.6.1 reflects historic opex figures stated in nominal dollars and all expenditure forecasts for the forthcoming regulatory period are stated in real 13/14 $'s. • The 1415 SCI assumptions includes in particular: COLA 2.5%, growth, market testing savings and transition in/out costs.

Table	Methodology	Assumptions
	7. Identify subcategory SCADA and Network Control from Work order data extract above and exclude for IT & Communications Asset Categories Client Device, Recurrent and Non-Recurrent expenditure as have individual subcategory. 8. Convert revised data forecast numbers to real 13/14 $'s applying escalation factors provided. 9. Extract standard control only component by calculating the average opex standard control % of each branch associated with these non-network categories	
2.6.1 (capex)	1. Extract Capital Expenditure data from the TM1 PNL cube for all Org Units across Endeavour coded to IT Capex Sub-Activities: • WD – WIP – IT&T Hardware • WE – WIP – IT&T Software • WF – WIP – IT&T Infrastructure 2. Extract data from TM1 cube Project Reporting against above Sub-Activities and allocate asset category against projects per RIN definition. 3. Forecasts for forthcoming regulatory period extracted from 1415SCI capex program. 4. Reconcile TM1 cube Project Reporting extract & 1415SCI program data to TM1 PNL cube IT Capex. 5. Convert forecast numbers to real 13/14 $'s applying escalation factors provided. 6. Extract standard control only component by reconciling to previous RINs then allocating variances and assuming a 4% alternate control allocation for forecast years.	• 1415 SCI capital program forward years are reflected in the data in TM1 cube PNL, IT Capex Sub Activities, with program details provided by the Information Communications and Technology Division. • Re-current refers to capital expenditures to Maintain Capability; example includes: applications and server refresh. • Non re-current refers to capital expenditures to Develop New Capabilities and New business enabling technologies, examples include: Transformation, Strategic Re-engineering, Process Re-engineering, CRM, Mobility and AMI. • Table 2.6.1 reflects historic opex figures stated in nominal dollars and all expenditure forecasts for the forthcoming regulatory period are stated in real 13/14 $'s.

Use of estimated information

While Endeavour Energy made an assumption in order to allocate the IT and Communications expenditure into the Asset Categories in the RIN templates, the opex and capex in table 2.6.1 reconciles to previous audited RINs (as outlined above), it has not used estimated Information as provided in the definitions with the Regulatory Information Notice.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems and reconciles to all reported IT and Communications opex and capex figures in previous audited RINs however assumptions were made in order to classify the data into Asset Categories. As a result, the information contained in the tables in section 2.6.1 is considered to be reliable.

2.6.1: Non Network Expenditure

Service Subcategory

Motor Vehicles

Compliance with requirements of the notice

The data presented in the tables contained in table 2.6.1 is consistent with the definition of Motor Vehicles Expenditure per the RIN definitions contained in Appendix F. In particular:

- The Opex data presented in tables 2.6 represents the total operating expenditure including leasing, fuel, registration, CTP insurance, self-insurance, inspections, labour, materials, maintenance, contractor and other operating expenses pertaining to all Motor Vehicle expenditure.

- The Capex data presented in tables 2.6 represents the total capital expenditure pertaining to all Motor Vehicle expenditure including procurement of motor vehicles, labour, materials and major overhaul costs.

- The non-network Motor vehicle opex and capex in table 2.6.1 is directly attributable to this expenditure category in this regulatory template. For the purposes of table 2.6.1 we have reported all capex and/or opex as *Direct Costs* as required, irrespective of them also being classified as *Corporate Overheads* or *Network Overheads* or other capex or opex categories.

Source of information

The information used to populate the tables contained in section 2.6.1 was extracted directly from TM1. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes.

Table	TM1 Cube	Description
2.6.1	PNL cube	The PNL cube contains General ledger information sourced from Ellipse (GL system) based on Endeavour's chart of accounts.

In addition, information was also sourced from:
- The Ellipse Equipment register was utilised in section 2.6.1 which was utilised to extract vehicle numbers and is extracted directly from MS Access query against the SQL server database which is extracted nightly from Ellipse. Query is run on parameters specified to extract the data; and

- Fuel reports provided by suppliers were utilised to calculate kilometres travelled

Methodology and Assumptions

The following table sets out the methodology applied to calculate the required data for the motor vehicles sections in table 2.6.1:

Table	Methodology	Assumptions
2.6.1 (opex)	1. The Opex data presented in table 2.6.1 was sourced from TM1 through the Fleet org units below which contain all motor vehicle expenditure. • S750 – Fleet Management • S751 – Fleet Operations • S752 - Vehicle Workshops • S753 – Fabrication Workshops 2. Historical data for the years 2008/09 to 2012/13 are based on actuals in TM1, 2013/14 figures are based on the Q2 Forecast, 2014/15 figures are based on the budget and 2015/16 to 2018/19 annual figures are sourced from the 2014/15 SCI version in TM1 for the outer years	• Motor vehicle leasing, fuel, registration and CTP insurance costs by vehicle type have been maintained since Endeavour started leasing vehicles in December 2009, thus allowing the classification of costs. Future year's cost have been allocated based on the forecasted fleet numbers • Motor vehicle leasing costs also includes the cost of leasing I-Safe devices since FY1213. • Fleet Labour, materials, contractors and other costs are not captured by vehicle type hence was apportioned based on advice from the Fleet manager • Self-insurance costs for future years are based on the FY1314 proportions for vehicle categories.
2.6.1 (capex)	1. The Capex data presented in table 2.6.1 was sourced from TM1 through org unit: • S350 – Fleet Capital 2. Historical data for the years 2008/09 to 2012/13 are based on actuals in TM1, 2013/14 figures are based on the Q2 Forecast, 2014/15 figures are based on the budget and 2015/16 to 2018/19 annual figures are sourced from the 2014/15 SCI version in TM1 for the outer years	

Use of estimated information

While Endeavour Energy made an assumption in order to allocate motor vehicle expenditure into the Asset Categories in the RIN templates, Labour, contractors, material and other costs were also apportioned based on estimated time spent on each vehicle category as advised by the Fleet Manager.

The opex and capex in table 2.6.1 reconciles to previous audited RINs (as outlined above), it has not used estimated Information as provided in the definitions with the Regulatory Information Notice.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems and reconciles to all reported motor vehicle opex and capex figures in previous audited RINs however assumptions were made in order to classify the data into Asset Categories. As a result, the information contained in the tables in section 2.6.1 is considered to be reliable.

2.6.1: Non Network Expenditure

Service Subcategory

Buildings & Property

Compliance with requirements of the notice

The data presented in the tables contained in table 2.6.1 is consistent with the definition of Non-network Buildings and Property Expenditure per the RIN definitions contained in Appendix F. In particular:

- The Opex and Capex data presented in table 2.6.1 represents the total operating expenditure including labour, plant, property, taxes, materials, maintenance, contractor and other operating expenses pertaining to all non-network building and property expenditure.

- The Capex data presented in tables 2.6 represents the total capital expenditure pertaining to all building and property expenditure.

- The non-network building and property opex and capex in table 2.6.1 is directly attributable to this expenditure category in this regulatory template. For the purposes of table 2.6.1 we have reported all capex and/or opex as *Direct Costs* as required, irrespective of them also being classified as *Corporate Overheads* or *Network Overheads* or other capex or opex categories.

Source of information

The information used to populate the tables contained in section 2.6.1 was extracted directly from TM1. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes.

Table	TM1 Cube	Description
2.6.1	PNL cube	The PNL cube contains General ledger information sourced from Ellipse (GL system) based on Endeavour's chart of accounts.

Methodology and Assumptions

The following table sets out the methodology applied to calculate the required data for the building and property expenditure sections in table 2.6.1:

Table	Methodology	Assumptions
2.6.1 (opex)	1. The Opex data presented in table 2.6 was sourced from TM1 through the Property Services org units below which contain all the non-network buildings and property expenditure • S200 - Facilities, Business & Information Support • S220 - Facilities Support - FSC	

Table	Methodology	Assumptions
	• S230 - Facilities Support - Office Accommodation • S500 - Security Management • S510 - Security Locking • S210 - Property Portfolio Management • S300 - Fleet & Property Management 2. Only 50% of S300 costs were allocated to Buildings & Property expenditure as this org unit contains the Property & Fleet branch management costs which are split between Property & Fleet. 3. Historical data for the years 2008/09 to 2012/13 are based on actuals in TM1, 2013/14 figures are based on the Forecast, 2014/15 figures are based on the budget and 2015/16 to 2018/19 annual figures are sourced from the 2014/15 SCI version in TM1 for the outer years.	
2.6.1 (capex)	1. The Capex data presented in table 2.6.1 was sourced from TM1 through the same org units as opex and for all costs coded to Sub-Activity WC – Non Infrastructure Buildings. 2. Historical data for the years 2008/09 to 2012/13 are based on actuals in TM1, 2013/14 figures are based on the Forecast, 2014/15 figures are based on the budget and 2015/16 to 2018/19 annual figures are sourced from the 2014/15 SCI version in TM1 for the outer years.	

Use of estimated information

While Endeavour Energy made an assumption in order to allocate non-network building and property expenditure into the Asset Categories in the RIN templates, the opex and capex in table 2.6.1 reconciles to previous audited RINs (as outlined above), it has not used estimated Information as provided in the definitions with the Regulatory Information Notice.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems and reconciles to all reported non-network building and property opex and capex figures in previous audited RINs however assumptions were made in order to classify the data into Asset Categories. As a result, the information contained in the tables in section 2.6.1 is considered to be reliable.

2.6.2: Non Network Expenditure

Service Subcategory

IT and communications expenditure

Compliance with requirements of the notice

The data presented in the tables contained in table 2.6.2 is consistent with the definition of Non-network IT and communications expenditure per the RIN definitions contained in Appendix F. In particular:

- The *Non-network IT & Communication - user numbers* are the active IT system log in accounts used for regulated purposes and the *Non-network IT & Communications – device numbers* are the number of client devices used to provide regulated services. Client Devices are hardware devices that accesses services made available by a server and may include desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones, tablets and laptops.

Source of information

The information used to populate the tables contained in section 2.6.2 financials was extracted directly from TM1. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes.

Table	TM1 Cube	Description
2.6.2	Labour Info cube	The PNL cube contains Staff Details and FTE/Headcount.
2.6.2	Reg Accounts cube	The Reg Accounts cube provides financials for Reg period.
2.6.2	AER Dollars by Account cube	The AER Dollars by Account cube provides financials for forecast AER period.

Set out in the table below are the specific reports used to obtain the required information for section 2.6.2:

Table	Descriptor Metrics	Description / Source
2.6.2	Employee Numbers	Historic – monthly headcount staff listing as agreed with Human Resources on a monthly basis. Q2 Forecast and 2014/15 Budget – TM1 Labour Info cube 2015/16 to 2018/19 – SCI Opex assumptions
2.6.2	User Numbers	CGI Active Directory Listing
2.6.2	Number of Devices	CGI Billing report Schedule U – total desktop & laptops

To proportion metrics to regulated services, historic Standard Control % for PC/Devices was sourced from Regulatory Accounts.

Methodology and assumptions

The following table sets out the methodology applied to calculate the required data for the building and property expenditure sections in table 2.6.2:

Table	Methodology	Assumptions
2.6.2	1. Employee Numbers extracted from Monthly Headcount Staff Listing Report for historic data. 2. Employee Numbers extracted from Labour Info cube for 2013/14 Q2 Forecast and 2014/15 Budget. 3. Employee Numbers extracted for 2015/16 onwards using 1415SCI opex assumptions. 4. Standard Control % extracted from TM1 cube Reg Accounts for historic & 13/14 Q2 forecast, and TM1 cube AER Dollars by Account for 2014/15 onwards, for Labour category. 5. Apply extracted Standard Control % against Employee Numbers for regulated data.	• Employee Numbers are headcount numbers at June for each year. Headcount numbers provide a better comparison for user and device numbers. • 1415SCI Opex Assumptions for Employee Numbers from 2015/16 onwards includes a reduction in headcount due to the capital rationalisation process. • Standard Control % allocation sourced from Reg Accounts and AER cubes for Endeavour Energy, Labour category for each year.
2.6.2	1. User Numbers for 2013/14 Q2 Forecast extracted from CGI Active Directory Listing (@ March 2014). 2. User Numbers for 2014/15 onwards incorporate 2013/14 as the base and adjusted for movement in Employee numbers. 3. Apply extracted Standard Control % allocation against User Numbers for regulated data.	• CGI Active Directory Listing lists every active account at the present time, Endeavour, CGI, Optus and any other third party who needs to have access to our systems. Periodically this list is reviewed and updated and access is removed for employees who have left the organisation, contractors who no longer need to have access etc. • Utilised percentage allocation of current CGI Active Directory Listing number of users against Device Numbers and applied across each year. • Standard Control % allocation sourced from Reg Accounts and

Table	Methodology	Assumptions
		AER cubes for Information Communication & Technology Division, Maintenance Category for each year.
2.6.2	1. Device Numbers (excluding PDA's) extracted from CGI Billing report Schedule U – total desktop & laptops for historic data. 2. Device Numbers (excluding PDA's) for 2013/14 Forecast extracted from current listing (@ March 2014) 3. Device Numbers for 2014/15 onwards incorporate 2013/14 as the base and adjusted for movement in Employee numbers. 4. Device Numbers (PDA only) extracted from Optus and Telstra Billing reports for historic data. 5. Device Numbers (PDA only)) for 2013/14 Forecast extracted from current listing (@ January 2014) 6. Apply extracted Standard Control % against Device Numbers for regulated data.	• CGI Billing Report, Schedule U provides number of desktops and laptops. Utilised CSI Billing Reports for June for each year for historic data. • Optus and Telstra billing reports provide PDA charged with June utilised for historic data. • Standard Control % allocation sourced from the Regulatory Accounts , PC/Device allocation, for historic and AER for Information Communication & Technology Division, Maintenance Category for 2013/14 Q2 Forecast and forward years.

Use of estimated information

Endeavour Energy has used estimated information in table 2.6, section 2.6.2 for forecasts as outlined in the methodology above as information was not captured and reported for these metrics.

Endeavour Energy considers the approach described in methodology as the most reasonable as it utilises the current available information to formulate historic and future data.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems. As a result, the information contained in the tables in section 2.6.1 is considered to be reliable.

2.6.3: Non Network Expenditure

Service Subcategory

Motor vehicles expenditure

Compliance with requirements of the notice

The data presented in table 2.6.3 is consistent with the definitions of Motor Vehicle Descriptor Metrics per the RIN definitions contained in Appendix F.

Source of information

The information used to populate the tables contained in section 2.6.3 was extracted from internal Fleet management reports and is consistent with other benchmarking figures provided to Networks NSW. Fleet Service Provider reports were also utilised to extract average kilometres travelled.

Methodology and assumptions

The following table sets out the methodology applied to calculate the required data for the Annual Descriptor metrics for motor vehicles in table 2.6.3:

Table	Methodology	Assumptions
2.6.3	1. **Average kilometres travelled** were derived from Fuel reports provided by leasing companies (Fleet-Plus & SG Fleet) for the leased vehicles and from the Fuel companies (Shell & Caltex) for company owned vehicles. 2. **Numbers purchased** were extracted from the Equipment register in Ellipse 3. **Numbers leased** were based on reports provided by leasing companies (Fleet-Plus & SG Fleet) 4. **Number in Fleet** is the combination of leased vehicles and company owned vehicles.	• Average kilometres travelled were calculated based on FY12 and FY13 actuals. Given the unavailability of prior year's information, these were assumed to be the same as FY12. The forecasted average kilometres for future years are based on FY13 actuals as this is the most current available information. • Average vehicle numbers throughout the year were derived for FY10-11 to FY12-13. Due to unavailability of monthly information for prior years, they are based on figures as at 30th June 2009 and 30th June 2010.

Use of estimated information

Endeavour Energy has used estimated information in table 2.6.3 as outlined in the methodology above as information has not historically been captured and reported for these metrics.

Endeavour Energy considers the approach described in the methodology as the most reasonable as it utilises the current available information to formulate historic and future data.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems (with the exceptions outlined in the assumptions). As a result, the information contained in table 2.6.3 is considered to be reliable.

Worksheet 2.7 – Vegetation management

2.7.1 Vegetation management metrics

Compliance with requirements of the notice

The data presented in table 2.7.1 is consistent with the requirements of the Economic Benchmarking RIN. In particular, Endeavour Energy has provided data for the descriptor metrics by zone 1. The remaining cells have been blacked out as there are no other zones.

Refer to our regulatory proposal and Attachment 5.05 to our proposal for a map of our network area (and vegetation management zone). Refer to Attachment G to this RIN for our Vegetation management compliance audits and Reset RIN template 7.3 Obligations for details on the regulations and standards that apply to Endeavour Energy.

Source of information

Information provided in table 2.7.1 was sourced from Endeavour Energy's Geographical Information System (GIS), Rural Fire Service map polygons applied to the GIS, a Scope and Audit review of vegetation management contracts using the work flow management system AM4, and the Bureau of Meteorology web site and the Vegetation Program Completion Process.

Work flow Management System AM4:

The Active Tree Service "AM4 System" delivers to Endeavour Energy potential service improvements and cost savings through the provision of an auditable, sophisticated workflow management system that is geospatially enabled (including tracking) with real time data capability.

This product is built on Microsoft SQL Server 2008 R2 technologies, Microsoft SharePoint 2010 technologies, and the Esri ArcGIS Server and ArcGIS Mobile products.

Endeavour Energy implements the workflow described below to manage;

1. Vegetation Management contracts
2. Auditing function
3. the Defect management system to integrate with the Ellipse corporate asset database.

The Vegetation Program Completion Process is detailed in Branch Work Place Instruction WVM 0838.The purpose of this Branch Workplace Instruction is to define the process, including clarity of roles and responsibilities within the Vegetation Control Section of the Maintenance Branch. It is also to minimise business risk. It should be noted by all parties that being flexible and adaptable to the evolving needs of the business is a necessary element of this process and additional information may be requested by the Program Director, the Vegetation Control Manager or the Vegetation Contracts Operations Manager, as required, at any point in the program delivery cycle.

This Branch Workplace Instruction is underpinned by effective, collaborative working relationships between all parties. Equally important is all parties fostering effective relationships with other stakeholders.

The information provided in table 2.7.2 was provided from the financial accruals and work orders contained in corporate database Ellipse.

Methodology and assumptions

The assumptions made in regard to the data in Table 2.7.1 are as follows:

1. Average number of trees per urban and CBD vegetation maintenance span?
   Average = total number of trees identified for trimming in urban areas divided by the total number of maintained spans in urban areas.

2. Average number of trees per rural vegetation maintenance span?
   Average = the total number of trees identified for trimming in rural areas divided by the total number of maintained spans in rural areas.

Table 2.7.1 identifies a descriptor for vegetation corridors in kilometres. The length of the corridors has described urban and cbd and rural and the data is developed from a spatial query and uses the Urban Centres and Localities (UCL) dataset from Australian Bureau of Statistics attached to the GIS data clipped to the Endeavour Energy franchise. The query describes the length of vegetation corridors as zero as these are included in the route line length and is not in addition to the route line length.

Use of estimated information

In table 2.7.1 the total length of maintenance spans are estimated information for 2009 to 2012 as a pro rata of 2013 actual maintenance spans..

Reliability of information

All the information provided represents actual information extracted from Endeavour Energy's reporting systems and reconciled to reported figures in previous audited benchmark RINs. As a result the information contained in table 2.7.1 is considered to be reliable.

2.7.2 Vegetation management costs

Compliance with requirements of the notice

The data presented in the tables contained in section 2.7.2 is consistent with the requirements of the Economic Benchmarking RIN.

Since Endeavour Energy completed the 2009 Distribution Determination RIN there have been a range of structural and operational changes across divisions as well as within the network functions.

As a consequence, Endeavour Energy's activities and sub-activities that are used to identify actual costs by the opex categories contained in the annual RIN were reviewed and updated to ensure that the relationship between internal functions and reported costs is as robust and accurate as possible.

The historical cost metrics in Table 2.7.2 has been categorised and reported in a manner that is consistent with Endeavour Energy's approved Cost Allocation Method and most recent annual reporting RIN activities in the 2012/13 Regulatory Financial Statements.

The expenditure on vegetation corridor clearance and other vegetation management costs are included in the tree trimming(excluding hazard trees) expenditure line. Endeavour Energy's systems do not capture data on 'vegetation corridor clearance' and 'other vegetation management costs' as they are defined in the RIN. In the absence of both technical and financial information for these expressly termed classifications, Endeavour Energy cannot form a basis for estimation of their volumes or costs.

Source of information

The information used to populate the tables contained in tables 2.7.2 was extracted directly from TM1 and work order account codes in Ellipse. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations. It is a cube based technology which allows rules to be created between cubes and within cubes.

Methodology and assumptions

The information in table 2.7.2 was already prepared and reported in the Annual Financial Statements for each year of the reported periods and the information has been transposed from the final Annual Financial Statements (rather than being re-performed).

Set out in the table below are the specific cubes used to obtain the required information for tables 2.7.2, along with a description in relation to the use of the cubes by Endeavour Energy:

Table	TM1 Cube	Description
2.7.2	Reg Accounts cube	The Reg Accounts cube is used by Endeavour Energy to store and report the Opex into the service categories (i.e. Standard Control, Alternate Control and Unregulated categories) at the account code level. It is the primary tool used to allocate opex in accordance with Endeavour Energy's approved Cost Allocation Method. Standard control vegetation data was extracted from the TM1 Reg Accounts cube at the account code level (N level org units) for each financial year for the category called "Regulated Network $".

Use of estimated information

All the information provided represents actual information extracted from Endeavour Energy's reporting systems and reconciled to reported figures in previous audited benchmark RINs. As a result the information contained in table 2.7.2 is considered to be reliable.

Reliability of information

All the information provided represents actual information extracted from Endeavour Energy's reporting systems and reconciled to reported figures in previous audited RINs. As a result the information contained in table 2.7.2 is considered to be reliable.

Worksheet 2.8 – Maintenance

2.8.1 Routine and non-routine maintenance metrics

Compliance with requirements of the notice

Historical numbers of assets and number of assets maintained between years 2008/09 – 2012/13 have been entered and therefore complies with requirements.

Source of information

Data was obtained from VDA models, past SNMPs, Network Statistics, GIS and Business management standards (see below comments table).

Past Strategic Network Maintenance Plans (SNMP) / Network Maintenance Implementation Plans (NMIP) present the proposed maintenance targets for past years. Compliance of actual maintenance achievements is close to 100% of the target. Therefore it was assumed that actual units maintained is approximately equal to the proposed targets in the SNMP/NMIP.

Methodology and assumptions

See below comments table.

Use of estimated information

Data provided is as represented in SNMP/NMIP Documents, VDA models, GIS and Network statistics

Average ages were estimated by examining current ages and back-calculating using historical WARL information that was kept by the section.

Average ages for non CBD cables were estimated using average ages and total number of network underground cables for LV – 22kV and 33kV and above.

Reliability of information

Actual numbers from VDA models, past SNMP/NMIPs, Network Statistics, GIS and Business management standards were used

Areas in the tables were data was unavailable were filled with zeroes as per instructions.

2.8.2 Routine and non-routine maintenance costs

Compliance with requirements of the notice

Financial Costs of asset maintenance between years 2008/09 – 2012/13 have been entered and therefore complies with requirements.

Source of information

Data was obtained from financial standard control opex records.

Methodology and assumptions

See below comments table.

Use of estimated information

Some financial data was recorded as lump sums with no breakdown. Sub-transmission and Zone substation and Distribution substation routine maintenance lump sum expenditure was broken down by viewing past SNMP documents to estimate approximate ratios for each type of equipment

Sub-transmission and Zone substation and Distribution substation non-routine maintenance lump sum expenditure was broken down by viewing Ellipse work orders in and estimating ratios of Fault & Emergency and Condition Based work orders for each type of equipment.

Reliability of information

Actual numbers from financial standard control opex records were used

Areas in the tables were data was unavailable were filled with zeroes as per instructions.

Comments Table

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY	UNIT OF MEASURE	Assets at Years End	Assets inspected/ maintained	Inspection/ maintenance cycles	Routine Maintenance	Non-Routine Maintenance
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	POLE TOPS AND OVERHEAD LINES	NUMBER OF POLES (000'S)	Network Statistics/ GIS	SNMP - OLI/GLI (No info for 08/09-09/10 but numbers estimated based on number of poles and number of inspections for other years)	OLI GLI cycle	POLE TOPS AND OVERHEAD LINES	NUMBER OF POLES (000'S)
	SERVICE LINES	NUMBER OF CUSTOMERS (000'S)	Network Statistics/ GIS	No Historical data available	Not Applicable	SERVICE LINES	NUMBER OF CUSTOMERS (000'S)
POLE INSPECTION AND TREATMENT	ALL POLES	NUMBER OF POLES (000'S)	Network Statistics/ GIS	SNMP - OLI/GLI (No info for 08/09-09/10 but numbers estimated based on number of poles and number of inspections for other years)	OLI GLI cycle	ALL POLES	NUMBER OF POLES (000'S)
OVERHEAD ASSET INSPECTION	ALL OVERHEAD ASSETS	LINE PATROLLED (ROUTE KM)	Network Statistics/ GIS	Estimated on a 4.5 yearly inspection cycle (in reality this inspection cycle only applies for dist. assets)	OLI GLI cycle Dist. MMI0012 transmission	ALL OVERHEAD ASSETS	LINE PATROLLED (ROUTE KM)
NETWORK UNDERGROUND CABLE MAINTENANCE : BY VOLTAGE	LV - 11 TO 22 KV	LENGTH (KM)	Network Statistics/ GIS	No Historical data available	No Dist. cable inspections	LV - 11 TO 22 KV	LENGTH (KM)
	33 KV AND ABOVE	LENGTH (KM)	Network Statistics/ GIS	Estimated from Number of cables and 6 yearly inspection	MMI0006	33 KV AND ABOVE	LENGTH (KM)
NETWORK UNDERGROUND CABLE MAINTENANCE : BY LOCATION	CBD	LENGTH (KM)	No CBD assets in the network	No CBD assets	No CBD assets	CBD	LENGTH (KM)
	NON-CBD	LENGTH (KM)	Sum of all network underground cables by voltage	Same as inspections of cables voltages at or above 33kV	Only voltages at 33kV and above are inspected	NON-CBD	LENGTH (KM)
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION TRANSFORMERS	NUMBER OF INSTALLED TRANSFORMERS (000'S)	VDA - 11kV Cable box Tx, 1-3 ph Pole mount Tx, SWER Pole mount Tx, Pad mount Tx. (No info for 09/10-10/11 numbers estimated by assuming linear progression of asset growth)	Number same as Dist. Substation Property inspections	SMI101	DISTRIBUTION SUBSTATION TRANSFORMERS DISTRIBUTION SUBSTATION SWITCHGEAR (WITHIN-SUBSTATIONS AND STAND-ALONE SWITCHGEAR)	NUMBER OF INSTALLED TRANSFORMERS (000'S)

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY	UNIT OF MEASURE	Assets at Years End	Assets inspected/ maintained	Inspection/ maintenance cycles	Routine Maintenance	Non-Routine Maintenance
	DISTRIBUTION SUBSTATION SWITCHGEAR (WITHIN-SUBSTATIONS AND STAND-ALONE SWITCHGEAR)	NUMBER OF SWITCHES (000'S)	VDA – (11 & 22kV only) ABS, Fuses, Links, Sectionalisers, LV Links (No info for 09/10-10/11 numbers estimated by assuming linear progression of asset growth). It is assumed that this includes switches within substations and ABSs in the field	SNMP(Distribution) – ABS, RGB12, Holec MD4 (No info for 09/10 but number is estimated based on number of switches and number of inspections for surrounding years)	SMI101	DISTRIBUTION SUBSTATION - OTHER EQUIPMENT	NUMBER OF SWITCHES (000'S)
	DISTRIBUTION SUBSTATION - OTHER EQUIPMENT	DNSP TO NOMINATE	No Historical data available	No Historical data available	Not Applicable		DNSP TO NOMINATE
	DISTRIBUTION SUBSTATION - PROPERTY	NUMBER OF DISTRIBUTION SUBSTATIONS (000'S)	Network Statistics/ GIS	SNMP - Dist Substations (No info for 09/10 but number is estimated based on number of subs and number of inspections for other years)	SMI101	DISTRIBUTION SUBSTATION - PROPERTY	NUMBER OF DISTRIBUTION SUBSTATIONS (000'S)
ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - ZONE SUBSTATION	NUMBER OF ZONE SUBSTATION TRANSFORMERS (000'S)	VDA-11/22kV, 132/11kV, 132/22kV,33/11kV, 66/11kV and 66/22kV Txs (No info for 09/10-10/11 numbers estimated by assuming linear progression of asset growth)	SNMP - Power Trf (No info for 09/10 but number is estimated based on number of Txs and number of inspections for other years)	SMI100	TRANSFORMERS - ZONE SUBSTATION TRANSFORMERS - DISTRIBUTION TRANSFORMERS - HV	NUMBER OF ZONE SUBSTATION TRANSFORMERS (000'S) NUMBER OF DISTRIBUTION TRANSFORMERS WITHIN ZONE SUBSTATIONS (000'S)
	TRANSFORMERS - DISTRIBUTION	NUMBER OF DISTRIBUTION TRANSFORMERS WITHIN ZONE SUBSTATIONS (000'S)	Assumption: Estimated by one unit per zone substation	SNMP - Aux Tx (No info for 09/10 number estimated from surrounding years)	SMI100		
	TRANSFORMERS - HV	NUMBER OF HV TRANSFORMERS (000'S)	No HV Txs in Zone substations	No HV Txs in Zone substations	Not Applicable		NUMBER OF HV TRANSFORMERS (000'S)
	ZONE SUBSTATION - OTHER EQUIPMENT	DNSP TO NOMINATE	No Historical data available	No Historical data available	Not Applicable	ZONE SUBSTATION - OTHER EQUIPMENT	DNSP TO NOMINATE
ZONE SUBSTATION PROPERTY MAINTENANCE	ALL ZONE SUBSTATION PROPERTIES	NUMBER OF ZONE SUBSTATION PROPERTIES MAINTAINED (000'S)	Network Statistics/ GIS (zone substation only, excludes sub-transmission substations)	SNMP - Zone Substations (No info for 09/10 but number is estimated based on number of subs and number of inspections for other years)	SMI100	ALL ZONE SUBSTATION PROPERTIES	NUMBER OF ZONE SUBSTATION PROPERTIES MAINTAINED (000'S)

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY	UNIT OF MEASURE	Assets at Years End	Assets inspected/ maintained	Inspection/ maintenance cycles	Routine Maintenance	Non-Routine Maintenance
PUBLIC LIGHTING MAINTENANCE	MINOR ROADS	NUMBER OF PUBLIC LIGHTS MAINTAINED (000'S)	Network Statistics/ GIS - Includes minor and major roads	No Historical data available	MMI0003	MINOR ROADS	NUMBER OF PUBLIC LIGHTS MAINTAINED (000'S)
	MAJOR ROADS	NUMBER OF PUBLIC LIGHTS MAINTAINED (000'S)	Minor & Major roads included in above cell	No Historical data available	Not Applicable	MAJOR ROADS	NUMBER OF PUBLIC LIGHTS MAINTAINED (000'S)
SCADA & NETWORK CONTROL MAINTENANCE	SCADA & NETWORK CONTROL MAINTENANCE	Number of SCADA Substation sites	VDA - SCADA sub sites (No info for 09/10-10/11 numbers estimated by assuming linear progression of asset growth)	SNMP (No info for 09/10 but number is estimated based on number of SCADA systems and number of inspections for other years)	SMI100	SCADA & NETWORK CONTROL MAINTENANCE	Number of SCADA Substation sites
PROTECTION SYSTEMS MAINTENANCE	PROTECTION SYSTEMS MAINTENANCE	Number of Protection Schemes	SNMP (No info for 08/09 – 10/11 number estimated from number of inspections and total number of other years)	SNMP (No info for 09/10 number estimated from surrounding years)	PMI4120	PROTECTION SYSTEMS MAINTENANCE	Number of Protection Schemes
OVERHEAD AND MISCELLANEOUS		Miscellaneous					Miscellaneous

Worksheet 2.9 – Emergency response

2.9.1 Emergency response expenditure

Compliance with requirements of the notice

The data presented in table 2.9.1 is consistent with the requirements of the Reset RIN. In particular:

- The data presented in table 2.9.1 (Emergency response expenditure) represents the opex split of emergency response expenditure into Standard Control Services with the definition of emergency response provided in Appendix F of the Regulatory Information Notice.

- The total emergency response expenditure costs listed in table 2.9.1 only relate to direct expenditure incurred to restore a failed component to an operational state including all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and/or repairs necessary.

- These total emergency response costs are primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by nonrelated entities.

- The total emergency response expenditure (A) in table 2.9.1 is the direct expenditure only and excludes overheads (Direct "Network" overheads and Indirect "Corporate" overheads) and reconciles to the total direct historical emergency response opex as disclosed in the previously audited Regulatory Accounting Statements.

- All emergency response expenditure in table 2.9.1 are *Direct Costs* only as outlined in section 1.15 in Appendix E (Principles and Requirements) of the Regulatory Information Notice and excludes expenditures on *Overheads* also as defined in Appendix E (Principles and Requirements) of the Regulatory Information Notice.

- Total historical opex reported in table 2.9.1 (A) aligns to the approach adopted for the Benchmarking RIN and in particular Table 3.1.1). This approach was adopted as there has been a material change (over the course of the back cast time series) in Endeavour Energy's basis of preparation for its Regulatory Accounting Statements. As a consequence, the opex reported in table 2.9.1 (A) is not consistent with the Opex reported for the 2005/06 to 2010/11 financial years at a regulatory category level, but does reconcile to the total historical Opex as disclosed in the Regulatory Accounting Statements.

  Since Endeavour Energy completed the 2009 Distribution Determination RIN there have been a range of structural and operational changes across divisions as well as within the network functions.

  As a consequence, Endeavour Energy's activities and sub-activities that are used to identify actual costs by the opex categories contained in the annual RIN were reviewed and updated to ensure that the relationship between internal functions and reported costs is as robust and accurate as possible. This review identified several improvements to the segregation of the standard control operating costs (which were unaffected by this review in aggregate) in the RIN operating cost categories as well as a change in the allocator for direct and indirect overhead costs from a percentage of direct labour to a percentage of direct operating expenditure.

Consequently, the main driver for Endeavour Energy's basis of preparation change in table 2.9.1 (A) is in the mix of costs being reported at a RIN category level for Emergency Response compared to the historical RINs due to the re-allocation of activities and sub-activities to better reflect the reporting costs by the RIN categories. This is also relevant for overhead costs, due to changes in corporate structures which can be directly attributed to the Standard Control Service, but not to an individual RIN category.

Source of information

- Total direct emergency response expenditure was extracted from the previous financial year regulatory accounting statement work papers.

- To complete parts (B) and (C) all emergency response transactions were also extracted from the General ledger (Ellipse - ERP). Endeavour uses Ellipse for various purposes including accounts payable; payroll; asset and equipment registers and financial reporting functions.

- Only those transactions with the following activity and sub activity combinations were applicable:

Activity	Sub Activity	Justification
All operating activities (excluding activity 11 – Third Party Impacts which is below)	RF - Fault and Emergency Repairs	Fault and Emergency repair costs are associated with the unscheduled maintenance or repair / replacement of major defective components associated with Endeavour Energy assets and equipment (e.g. through storm damage).
	74 - Unplanned Switching	Unplanned switching work costs are incurred and required for operational maintenance and construction work where no access permit has been obtained.
	75 - Emergency Switching	Emergency switching work costs relate to the provision of switching and fault location on the network under emergency conditions and includes work carried out by EMSOs.
11 - Third Party Impacts	All sub activities	Costs incurred as a result of events such as motor vehicle accidents, vandalism, and impact damage to poles, mains, substations and street lighting requiring immediate rectification and/or repairs to make safe and operational.

- A list of Major event days was provided by the Network Performance Review Manager.

Methodology and assumptions

Table	Methodology	Assumptions
2.9.1 (A) Total Emergency Response expenditure	Use the Emergency Response direct expenditure derived for the Benchmarking RIN.	

Table	Methodology	Assumptions
2.9.1 (B) Major Storms O&M expenditure	• Extract all emergency response transactions from the ellipse transaction database in Microsoft Access. • Group the transactions which contain a parent work order related to a storm event. Endeavour Energy uses parent work orders to capture / pool costs together to enable reporting of major weather or fire events.	The AER defines a major storm as Tropical cyclones of Category 1 and above as classified by the Australian Bureau of Meteorology. However our historical records do not contain sufficient information to be able to determine if each major storm event meets their criteria. Therefore we have assumed all storm events that warranted the creation of their own individual parent work order and have total costs exceeding $50K meet the definition of a Major Storm.
2.9.1 (C) Major Event Days O&M expenditure	• Extract all emergency response transactions from the ellipse transaction database in Microsoft Access. • Using the list of major event days provided by the Network Performance Review Manager match these events with the expenditure captured by the parent work orders raised for each event. • Group the transactions under each of these parent work orders and report the totals for each major event day.	

Use of estimated information

While Endeavour Energy made an assumption in order to ensure total direct standard control opex related to emergency response reported at (A) in table 2.9.1 reconciles to previous audited RINs (as outlined above), it has not used estimated Information as provided in the definitions with the Regulatory Information Notice.

All historical information provided for in these tables consists of actual information and judgement was used to define a major storm event. This is because Endeavour Energy does not keep records on whether each storm event meets the definition of a category 1 tropical cyclone.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems and reconciles to all reported direct emergency response opex figures in previous audited RINs however assumptions were made in order to classify the transactional data as a major storm. As a result the information contained in table 2.9.1 is considered to be sufficiently reliable.

Worksheet 2.10 – Overheads

2.10.1 Network overheads expenditure & 2.10.2 Corporate overheads expenditure

Compliance with requirements of the notice

The data presented in tables 2.10.1 and 2.10.2 is consistent with the requirements of the Reset RIN. In particular:

- The data presented in table 2.10.1 (Network Overheads expenditure) represents the opex split of network overheads expenditure into Standard Control Services with the definition of network overheads provided in Appendix F of the Regulatory Information Notice.

- Endeavour Energy has previously reported *network operating costs* in its Regulatory Accounting Statements, therefore we have reported this expenditure under network overhead in regulatory template 2.10.1 and into the six mandatory subcategories provided.

- Network operating costs are disaggregated into the following six sub categories: network management, network planning, network control and operational switching, quality and standard functions, project governance and related functions and other.

- Endeavour Energy has previously reported *corporate overheads* in its Regulatory Accounting Statements and are not included in any other overhead subcategory, therefore we have reported this expenditure in regulatory template 2.10.2.

- The data in tables 2.10.1 and 2.10.2 are overhead costs that are reported before it has been allocated to services or direct expenditure and before any capitalisation. The historical opex in tables 2.10.1 and 2.10.2 has been categorised and reported in a manner that is consistent with Endeavour Energy's approved Cost Allocation Method and most recent annual reporting RIN activities in the 2012/13 Regulatory Financial Statements.

- The historical opex reported in tables 2.10.1 and 2.10.2 for the 2008/09 to 2012/13 financial years aligns to the approach adopted for the Benchmarking RIN and in particular Table 3.1.1). This approach was adopted as there has been a material change (over the course of the back cast time series) in Endeavour Energy's basis of preparation for its Regulatory Accounting Statements. As a consequence, the opex reported in tables 2.10.1 and 2.10.2 is not consistent with the Opex reported for the 2008/09 to 2010/11 financial years at a regulatory category level, but does reconcile to the total historical Opex as disclosed in the Regulatory Accounting Statements.

Since Endeavour Energy completed the 2009 Distribution Determination RIN there have been a range of structural and operational changes across divisions as well as within the network functions.

As a consequence, Endeavour Energy's activities and sub-activities that are used to identify actual costs by the opex categories contained in the annual RIN were reviewed and updated to ensure that the relationship between internal functions and reported costs is as robust and accurate as possible. This review identified several improvements to the segregation of the standard control operating costs (which were unaffected by this review in aggregate) in the RIN operating cost categories as well as a change in the allocator for direct and indirect overhead costs from a percentage of direct labour to a percentage of direct operating expenditure.

Consequently, the main driver for Endeavour Energy's basis of preparation change in tables 2.10.1 and 2.10.2 is in the mix of costs being reported at a RIN category level compared to the historical RINs due to the re-allocation of activities and sub-activities to better reflect the reporting costs by the

RIN categories. This is also relevant for overhead costs, due to changes in corporate structures which can be directly attributed to the Standard Control Service, but not to an individual RIN category.

- Endeavour Energy capitalises a portion of its overheads which are directly attributable to capital works in order to facilitate the identification of the true cost of activities performed. This enables capitalised projects with enduring economic benefit to be capitalised at their true cost.

Source of information

Historical information sourced from the Reg accounts cube in TM1 and the forecast data was sourced from the AER Dollars by Account cube also in TM1. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes.

Table	TM1 Cube	Description
2.10.1 and 2.10.2	Reg Accounts cube	The Reg Accounts cube is used by Endeavour Energy to store and report the Opex into the service categories (i.e. Standard Control, Alternate Control and Unregulated categories) at the account code level. It is the primary tool used to allocate historical opex in accordance with Endeavour Energy's approved Cost Allocation Method.
2.10.1 and 2.10.2	AER Dollars by Account cube	The AER Dollars by Account cube is used by Endeavour Energy to store and report the forecast Opex for the 2014-19 regulatory period into the regulatory and service categories (i.e. Vegetation management, maintenance & repair as well as Standard Control, Alternate Control and Unregulated categories) at the account code level. It is the primary tool used to allocate future opex in accordance with Endeavour Energy's approved Cost Allocation Method.

The capitalised overheads was sourced from the historical Regulatory Accounts / RIN work papers based on the split between the network and corporate divisions.

Methodology and assumptions

Table	Methodology	Assumptions
2.10.1 and 2.10.2	1. Extract opex data from the TM1 Reg Accounts cube at the account code level for each financial years in the Initial Period. Extract the data as Labour and non-labour line items. 2. Reconcile the total derived at the individual account code level to the total from the TM1 Reg Accounts cube (N Level Org Units) to ensure no account codes have been excluded.	- Immaterial variances (less than 0.2%) exist between TM1 Reg Accounts cube data and the information contained in previous audited RINs. These variances were added back to all RIN categories post allocation based on the proportion of costs in each of the

Table	Methodology	Assumptions
	3. Reconcile the total derived at the individual account code level to the total opex reported in previous RINs.	categories to ensure total opex reported for the Initial Period is consistent with previous audited RINs.
	4. Assign a reg accounts classification to the extracted TM1 data. This classification can be a direct network cost, direct network overhead or a corporate overhead cost. A direct network cost is assigned directly to a RIN category (e.g. maintenance & repair, emergency response etc.), direct network overheads are the remaining network operating costs that cannot be allocated directly to a RIN category and allocated on a pro rata basis, based on the proportions of the direct allocation and corporate overheads (and shared business unit costs) are allocated to the network business on a pro rata basis, based on the proportions of the sum of direct network costs and direct network overhead costs.	• Primary function of each org unit used to allocate network operating costs between management, network planning, network control and operational switching, quality and standard functions, project governance and related functions and other.
	5. Allocate the direct network overhead costs to those costs classified as direct network costs on a pro rata basis, based on the proportions of the direct allocation of network costs to each service category.	• Historically, the capitalised overheads have been reported differently over the two regulatory periods and the data is not always readily available. Therefore assumptions to allocate Ohs have been made in order to complete this template.
	6. Allocate the corporate overhead costs to the costs classified as direct network costs (as the network overhead costs were already allocated at step 5) on a pro rata basis, based on the proportions of the direct allocation of network costs (inclusive of network overhead costs) to each service category. This historical classification is also used to populate table 2.10.1 into the historical RIN categories.	• Capitalised overheads from 2008/09 to 2013/14 were not able to be disaggregated into the various RIN reporting categories and were therefore reported as one line item for standard
	7. Next, determine which of the mandatory six subcategories that the costs that have been	

Table	Methodology	Assumptions
	allocated to the category of "Prescribed services operating costs" (now called "Network Operating Costs"). Use judgement to assign the costs to a subcategory based on the account code combination, org unit or Branch in addition to the guidelines provided in Appendix E and Appendix F of the guidelines document. 8. Finally, due to the immaterial variances compared to the historical reported regulatory accounts/RINs, pro rata the difference over the results in step 7. 9. Then, add back the proportion of capitalised overheads from the historical period. *Note: given TM1 Reg Accounts cube data is available from 2008/09 onwards and represents previously reported figures, all information provided for this table consists of actual information (no estimated information required).*	control.

Use of estimated information

All historical information provided for these tables consists of actual information (no estimated information required). However, the split of overheads into the various categories in tables 2.10.1 and 2.10.2 did require some judgement to be applied to allocate the org unit by function.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems and has been reconciled to reported figures in previous audited RINs. As a result, the actual information contained in tables 2.10.1 and 2.10.2 is considered to be reliable.

Worksheet 2.11 – Labour

2.11.1 Labour cost metrics per annum

Compliance with requirements of the notice

The data presented in table 2.11.1 is consistent with the requirements of the Reset RIN. In particular the data presented in table 2.11.1:

- Reflects Labour costs and average staff levels only for the provision of standard control services and excludes Labour used in the provision of contracts for goods and services.

- The labour data (both employees and labour contracted through labour hire contracts) has been broken down into the *Classification Levels* provided in the relevant table in the template. We have explained how we have grouped workers into these Classification Levels.

- The quantities of labour, expenditure or stand down periods have not been reported multiple times across the tables.

- Assumes one ASL is classified as one full time equivalent employee undertaking standard control services work receiving salary or wages over the entire year.

- Assumes one full time employee equating to one FTE over the course of the year that spends 50% of their time on standard control services work is reported as 0.5 ASL.

- That the labour costs consist of labour hire, ordinary time earnings, other earnings and superannuation, but excludes overtime, allowances, bonuses and incentive payments and superannuation contributions.

Source of information

- Annual FTE listings were sourced from previous YTD Jun FTE reports stored on the Endeavour's shared network directory.

- Labour cost information was extracted from the PNL cube, Reg accounts cube and AER dollars by account cube in TM1. Endeavour Energy uses TM1, an OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes.

- Stand down occurrences were sourced from Cognos Impromptu. Cognos is a reporting tool used to extract data from ellipse – ERP.

- Average productive work orders were sourced from the annual FTE listings which provide the award / contract weekly hours per FTE which was then used to estimate the productive hours.

Methodology and assumptions

The following tables set out the methodology applied to obtain required data for each of the tables in section 2.11.1.

Employee Methodology

Table	Methodology	Assumptions
2.11.1 – Cost Metrics Per Annum	1. Extract historical FTE annual actual opening and closing balances by org unit from the monthly FTE reports stored on G:/ Drive. Future FTE numbers sourced from labour info cube in TM1 13/14 based on Q2 forecast and all other future years assumed to equal 14/15 budget less 54 FTEs in 15/16 and 102 FTEs in 16/17 due to capital investment prioritisation. Each FTE is also multiplied by the standard control % for their home org unit to ensure that the reported ASLs relate to standard control only.	• FTEs assumed to reduce 54 in 15/16 and 102 in 16/17 and then remain constant out to 18/19. • The standard control % for each org unit is assumed to apply equally to all employees within that org unit.
	2. Assign a labour classification level from the RIN table to each FTE	FTEs assigned to classification levels on the basis of position description. Network / Corporate allocation based on home org unit classification.
	3. Divide the opening and closing FTE balances for each year to obtain the average staffing level numbers	Assumed the opening and closing FTE balances would give a good representative of the annual averages
	4. Calculate total labour cost for regulated $'s only excluding overtime, bonuses and allowances. Extract the base data from the PNL cube and then map it against the reg and AER cubes to arrive at regulated only dollars for specific labour expense elements	None.
	5. Extract productive hours per FTE from monthly FTE reports and then average these hours against each labour classification level	Productive hours based on contract/award hours per week times 52.17 weeks per year multiplied by the average productive rate (84%).
	6. Extract all stand down transactions from ellipse and then average these against each labour classification level	None

Labour Hire Methodology

Table	Methodology	Assumptions
2.11.1 – Cost Metrics Per Annum	1. Extract agency labour dollars from the PNL cube in TM1 by org unit from 08/09 to 18/19. Convert all dollars to real 14/15 $'s	
	2. Extract agency staff listing for the 14/15 budget from the labour info cube in TM1.	

Table	Methodology	Assumptions
	3. Divide agency dollars for 14/15 by the staff listing for 14/15 to work out an average amount per agency staff which can then be used to calculate agency staff numbers for past and future years which did not have agency staff numbers budgeted / recorded.	
	4. Multiply the total agency staff in each org unit by the % allocation of each labour type within each org unit to determine the labour classifications. Then multiply by the standard control % for each org unit to arrive at the final ASL per labour classification for labour hire.	
	5. Calculate total agency labour cost for regulated $'s only. Extract the base data from the PNL cube and then map it against the reg and AER cubes to arrive at regulated only dollars for specific labour expense elements	
	6. Productive hours for labour hire assumed to match internal staff averages	Labour hire productive hours assumed to match internal productive hours
	7. No stand down occurrences for labour hire were found	

Use of estimated information

Estimated information was used in the following instances:

- FTEs had to be subjectively assigned to each labour classification level since Endeavour Energy currently does not use these categories to classify labour. The assignment to each classification was based on an assessment of each FTEs position description.

- FTEs assumed to reduce 54 in 15/16 and 102 in 16/17 and then remain constant out to 18/19. This estimated was based our capital and operating expenditure profile over this period.

- Productive hours for each FTE were estimated since Endeavour Energy reporting systems did not have the capability to report the productive hours per FTE for the time period requested. Estimate of productive hours based on contract/award hours per week times 52.17 weeks per year multiplied by the average productive rate (84%).

- Accurate labour hire numbers are only available for the 14/15 budget. All other years only contain dollar amounts for labour hire hence an estimated amount per labour hire FTE had to be calculated and applied to all other past and future years.

Reliability of information

FTE numbers, labour $'s and stand down occurrences represent actual information extracted from Endeavour Energy's reporting systems and is considered reliable. Although significant assumptions needed to be made to classify the data into the various labour classification levels as well as determine the average productive hours there was no other alternative available to present the data. Therefore the data provided should be considered to be reliable.

2.11.2 Labour extra descriptor metrics for current year

Compliance with requirements of the notice

The data presented in table 2.11.2 is consistent with the requirements of the Reset RIN.

Source of information

- Average productive work hours – ordinary time for the current year (2013/14) was sourced from table 2.11.1.

- Average hourly rates for ordinary and overtime for the current year (2013/14) were sourced from the labour info cube in TM1.

- Average productive work hours – over time for the current year (2013/14) was sourced from the labour hours cube in TM1. For instances where an org unit has forecast their 2013/14 overtime by dollars instead of hours their overtime dollars were extracted from the PNL cube and divided by their average overtime rate from the labour info cube.

Methodology and assumptions

Table	Methodology	Assumptions
2.11.2 – Labour extra descriptor metrics for current year	1. Provide average productive work hours per ASL for ordinary time for the current year.	Average productive work hours for 13/14 ordinary time already calculated in table 2.11.1
	2. Provide average productive work hours hourly rate per ASL for ordinary time.	• FTEs assigned to classification levels on the basis of position description. Network / Corporate allocation based on home org units • Ordinary time hourly rates including oncost were extracted from the labour info cube for each FTE listed in the Q2 13/14 forecast. Using the 13/14 labour classifications used in the workings for table 2.11.1 the average rate for each classification was then calculated.
	3. Provide average productive work hours per ASL for over time for the	• Extract overtime forecast dollars from the PNL cube by org unit

Table	Methodology	Assumptions
	current year.	- Calculate average overtime rate by org unit using the overtime rates from the labour info cube in TM1 - Divide the forecast dollars for each org unit by the average OT rate to convert dollars to hours. For org units that forecast OT by hours extract this data from the labour hours cube in TM1 - Multiply the hours for each org unit by the average staff classification split within each org unit to determine hours per staff classification. - Divide the OT hours per each staff classification by the average ASL for the current year in table 2.11.1 to determine the average per FTE
	4. Provide average productive work hours hourly rate per ASL for over time for the current year.	- Not all FTEs had an overtime rate in TM1 therefore an assumption had to be made regarding a reasonable rate for that relevant labour classification. - Over time hourly rates including oncost were extracted from the labour info cube for each FTE listed in the Q2 13/14 forecast. Using the 13/14 labour classifications used in the workings for table 2.11.1 the average rate for each classification was then calculated.
	5. Hourly rates for labour hire staff are not recorded and hence we are not able to report this in table 2.11.2	

Use of estimated information

Estimated information was used in the following instances:

- FTEs had to be subjectively assigned to each labour classification level since Endeavour Energy currently does not use these categories to classify labour. The assignment to each classification was based on an assessment of each FTEs position description.

- Productive hours for each FTE were estimated since Endeavour Energy reporting systems did not have the capability to report the productive hours per FTE for the time period requested. Estimate of productive hours based on contract/award hours per week times 52.17 weeks per year multiplied by the average productive rate (84%).

- Endeavour Energy forecasts overtime hours at the org unit not against each FTE. Therefore the data had to be provided at the org unit level and an assumption then made on the basis of the FTE types within each org unit how the overtime hours would be averaged against each labour classification level.

Reliability of information

FTE numbers, labour $'s and stand down occurrences represent actual information extracted from Endeavour Energy's reporting systems and is considered reliable. Although significant assumptions needed to be made to classify the data into the various labour classification levels as well as determine the average productive hours there was no other alternative available to present the data. Therefore the data provided should be considered to be reliable.

Worksheet 2.12 – Input tables

2.12.1 Input tables

Compliance with requirements of the notice

The data presented in worksheet 2.12 is consistent with the requirements of the Reset RIN. In particular:

- The total amounts reported in table 2.12 reconciles to the amounts reported in tables 2.7, 2.8, 2.10, 2.3, 2.5, 2.9, 4.1, 4.2, 4.3, 4.4 and 2.2.

- The opex and capex data reported in *Regulatory Templates* 2.12 is reported against the *Regulatory Year* on an as-incurred basis

Source of information

System Capex – Expense Type Allocations

- System capex data by project and expense type was extracted from the annual system capex reports for 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13

Opex – Expense Type Allocations

Set out in the table below is the specific cubes used to obtain the required information for table 2.12, along with a description in relation to the use of the cubes by Endeavour Energy:

Table	TM1 Cube	Description
2.12	Reg Accounts cube	The Reg Accounts cube is used by Endeavour Energy to store and report the Opex into the service categories (i.e. Standard Control, Alternate Control and Unregulated categories) at the account code level. It is the primary tool used to allocate opex in accordance with Endeavour Energy's approved Cost Allocation Method. Standard and alternate control opex data was extracted from the TM1 Reg Accounts cube at the account code level (N level org units) for each financial year for the categories called "Regulated Network $" and "Street Lighting $".
2.12	AER Dollars by Account cube	The AER Dollars by Account cube is used by Endeavour Energy to store and report the forecast Opex for the 2014-19 regulatory period into the regulatory and service categories (i.e. Vegetation management, maintenance & repair as well as Standard Control, Alternate Control and Unregulated categories) at the account code level. It is the primary tool used to allocate future opex in accordance with Endeavour Energy's approved Cost Allocation Method.

Opex and Capex Expenditure - Reset RIN Tables

- 2.7 Vegetation
- 2.8 Maintenance
- 2.10 Overheads
- 2.3 Augex
- 2.5 Connections

- 2.9 Emergency Response
- 4.1 Public Lighting
- 4.2 Metering
- 4.3 Fee Based Services
- 4.4 Quoted Services
- 2.2 Repex

Methodology and assumptions

Table	Methodology	Assumptions
2.12 Input Tables	1. Source the total amounts for each expenditure category from the relevant Reset RIN table. 2. Extract opex at the expense element level from the reg accounts and AER dollars by account cube in TM1. 3. Extract system capex at the expense type level from the annual system capex reports from 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13. 4. Map the opex and capex data to the completed RIN tables on the basis of reg account classifications and/or project numbers 5. Calculate the material, labour, contractor and other expenditure percentage allocation for each mapping category. 6. Multiply the relevant expenditure data from each RIN table by each relevant expenditure type percentage.	
2.12 Input Tables – Vegetation Management	1. Source the actual total annual expenditure amounts for the 2008/09 to 2012/13 financial years from Reset RIN table 2.7. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 to determine the proportional split by expense category to be used for the allocation of the expenditure from table 2.7 into the required categories (i.e. direct material cost, direct labour cost etc.) . 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Vegetation Management).	• Historically Endeavour Energy has not captured or reported the RIN categories (i.e. Vegetation Management) into expense classifications. To enable to completion of this template, proportions of actual and forecast expenditure was used to determine the split into the required categories (i.e. direct material cost, direct labour cost etc.).

Table	Methodology	Assumptions
	4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4. 6. Extract opex at the expense element level from the AER dollars by account cube in TM1 for 2014/15 to 2018/19 for the vegetation category	
2.12 Input Tables – Routine & Non Routine Maintenance	1. Source the actual total annual expenditure amounts for the 2008/09 to 2012/13 financial years from Reset RIN table 2.8. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 to determine the proportional split by expense category to be used for the allocation of the expenditure from table 2.8 into the required categories (i.e. direct material cost, direct labour cost etc.) . 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Inspection, Maintenance and Other Distribution Maintenance). 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4. 6. Extract opex at the expense element level from the AER dollars by account cube in TM1 for 2014/15 to 2018/19 for the categories inspection, maintenance & repair, network operating costs and other NM operating costs.	• Historically Endeavour Energy has not captured or reported the RIN categories (i.e. Routine & Non Routine Maintenance) into expense classifications. To enable to completion of this template, proportions of actual and forecast expenditure was used to determine the split into the required categories (i.e. direct material cost, direct labour cost etc.). • The RIN Categories of Inspection, Maintenance & Repair, Other NM operating Costs and Other Operating Expenditures were used in populating the 2014/15 to 2018/19 periods.
2.12 Input Tables – Overheads	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 2.10. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 and at the expense element level from the AER dollars by account cube in TM1 for 2014/15 to 2018/19 to determine the proportional split by expense category to be used for the allocation of the	• Historically Endeavour Energy has not captured or reported the RIN categories (i.e. Network Overheads or Corporate Overheads) into expense classifications. To enable to completion of this template, proportions of actual and forecast expenditure was used to

Table	Methodology	Assumptions
	expenditure from table 2.10 into the required categories (i.e. direct material cost, direct labour cost etc.) . 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Ntwk overhead allocation and OH allocation). 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	determine the split into the required categories (i.e. direct material cost, direct labour cost etc.).
2.12 Input Tables – Augex	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 2.3. 2. Extract system capex at the expense type level from the annual system capex reports from 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13. 3. Map the system capex data into the RIN category classifications on the basis of project numbers. 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	• Capex Project Number Mapping: o Subtransmission substations, switching stations, zone substations and subtransmisson lines = all PR*** projects excluding land purchases. o HV feeders = all HVW and OFP projects o Distribution substations = project LV001 o LV feeders = all other LV*** projects
2.12 Input Tables – Connections	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 2.5. 2. Extract system capex at the expense type level from the annual system capex reports from 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13. 3. Map the system capex data into the RIN category classifications on the basis of project numbers. 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be	• Capex Project Number Mapping: all projects starting with IC, NU, UR and AR.

Table	Methodology	Assumptions
	used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	
2.12 Input Tables – Emergency Response	1. Source the actual total annual expenditure amounts for the 2008/09 to 2012/13 financial years from Reset RIN table 2.9. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 to determine the proportional split by expense category to be used for the allocation of the expenditure from table 2.9 into the required categories (i.e. direct material cost, direct labour cost etc.) . 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Emergency Response). 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	• Historically Endeavour Energy does not forecast opex for major storms or major event days, therefore only actual data between 2008/09 and 2012/13 is provided in this table (by expense category).
2.12 Input Tables – Public Lighting	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 4.1. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 to determine the proportional split by expense category to be used for the allocation of the expenditure from table 4.1 into the required categories (i.e. direct material cost, direct labour cost etc.) and the system capex at the expense type level from the annual system capex reports from 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13. 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Public Lighting) to the system capex data SL projects. 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation.	• Capex Project Number Mapping: all projects starting with SL

Table	Methodology	Assumptions
	5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	
2.12 Input Tables – Metering	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 4.2. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 to determine the proportional split by expense category to be used for the allocation of the expenditure from table 4.2 into the required categories (i.e. direct material cost, direct labour cost etc.) and the system capex at the expense type level from the annual system capex reports from 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13. 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Metering) to the system capex meter data. 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	• Capex Project Number Mapping: all projects starting with MC
2.12 Input Tables – Fee based and Quoted services	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 4.3 & 4.4. 2. Extract opex at the expense element level from the reg accounts cube in TM1 for 2008/09 to 2013/14 to determine the proportional split by expense category to be used for the allocation of the expenditure from tables 4.3 & 4.4 into the required categories (i.e. direct material cost, direct labour cost etc.) . 3. Map the reg accounts cube opex account code data into the RIN category classifications (i.e. Customer Service) 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation.	• Historically Endeavour Energy has not captured or reported the RIN categories (i.e. Fee based and Quoted services) into expense classifications. To enable to completion of this template, proportions of actual and forecast expenditure was used to determine the split into the required categories (i.e. direct material cost, direct labour cost etc.).

Table	Methodology	Assumptions
	5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	
2.12 Input Tables – Repex	1. Source the actual total annual expenditure amounts for the 2008/09 to 2018/19 financial years from Reset RIN table 2.2. 2. Extract system capex at the expense type level from the annual system capex reports from 2008/09 to 2009/10 and the work papers to the annual RIN templates for 2010/11 to 2012/13. 3. Map the system capex data into the RIN category classifications on the basis of project numbers. Repex = All Essential spares, comms, automation, protection, power quality and smart grid projects 4. Calculate the proportion of materials, labour, contractor and other expenditure costs to be used in the category allocation. 5. Multiply the relevant expenditure data at step 1 by the percentage calculated at step 4.	• Capex Project Number Mapping: Repex = All Essential spares, communications, automation, protection, power quality and smart grid projects.

Use of estimated information

All historical information provided for these tables consists of actual information (no estimated information required). However, the split into the various expenditure categories did require judgement to be applied to map the expenditure in each source table to the data available at the expense element level.

Reliability of information

All historical information used to split the source data into the various expense types represents Actual Information extracted from Endeavour Energy's reporting systems and has been reconciled to reported figures in previous audited RINs. However significant assumptions needed to be made to map the opex and capex data to the information in the completed RIN templates. Therefore the data provided should be considered to be an estimate.

Worksheet 2.13 – Provisions

2.13.1 Changes in total provisions incl RPM and 2.13.2 Allocation of movement in total provisions incl RPM

Compliance with requirements of the notice

The data presented in table *2.13.1 Changes in total provisions* is consistent with the requirements of the Economic Benchmarking and Reset RIN. In particular:

- The data presented in table *2.13.1 Changes in total provisions* covers all regulatory periods with financial information on provisions for Standard Control Services in accordance with the cost allocation approach and the Regulatory Accounting Statements that were in effect for the relevant Regulatory year.
- The financial information provided is for each individual provision identified as follows:
  - A   Employee Benefits
  - B   Self Insurance
  - C   Defined Benefits Superannuation
  - D   Other
  - E   Dividends
- Each individual provision has been specified by name.

Source of information

The source information used to populate *table 2.13.1 Changes in total provisions* was extracted from the RIN for the relevant years, Balance Sheet and Capital working papers for the RIN and the Movement in Provisions schedule used as part of the Annual Statutory Financial Statements.

The information is located in G/CFO/NSW Treasury/Regulatory Financial Statements/Year/ (Balance Sheet and Capital) tabs.

All information included in the 2013/14 Forecast was sourced from Quarter 2 Forecasts in TM1.

Methodology and assumptions

The methodology used to populate table *2.13.1 Changes in total provisions* followed the same methodology in determining the closing balance of each provision in the RIN each year. The Movement in Provisions schedule details the opening balance, increases to provisions, amounts used (paid), unused amounts reversed and closing balance for each provision. The same methodology used in determining the closing balance was used to determine the percentage allocation of increases to provisions, amounts used (paid) and unused amounts reversed for each provision.

Between 2008 – 2010 the RIN was only separated between Regulated Retail, Regulated Distribution Network and Other. A further dissection was required to separate Regulated Distribution Network between Standard Control Services, Alternate Control Services and Other Unregulated based on the relevant allocation drivers for those particular years. Employee Benefits (A), Self Insurance (B) and Defined Benefits Superannuation (C) utilised the labour driver, Other (D) utilised a combination of labour, IT, opex and direct allocation drivers, and Dividends (E) utilised the Profit After Tax percentage from the profit & loss split of Regulated Distribution Network into Standard Control Services, Alternate Control Services and Other Excluded Services.

Also between 2008 – 2010 no roll forward of closing balances from the previous year was required. The closing balance was based on the appropriate percentage allocation of the closing balance sheet. The current practice was adopted from 2011 onwards. Unfortunately for the 2011 & 2012 RIN,

the opening balance was calculated by utilising the current year allocation driver, which was different from the closing balance from the previous year. All opening balance adjustments between 2006 and 2012 have been included in "increases to the provision". The 2013 RIN was calculated utilising the 2012 closing balance rolled forward.

Any impacts due to changes in discount rates have been included in "Increases to the provision" for Employee Benefits and Defined Benefits Superannuation. This information is unavailable for all the regulatory years.

Defined Benefits Superannuation "amounts used during the period" has been amended to reflect the additional contributions made to the defined benefits fund to reduce the deficit which had not been previously included in the RIN. This has been offset by a corresponding adjustment to the "Increases to the provision". The additional contributions were only incurred in the 2010, 2012, 2013 and 2014 financial years. There was also an error in the 2013 audited accounts where the liabilities paid and increase/decrease in provisions were incorrectly stated. The correct amounts have been included in the RIN accounts. The carrying amount at the end of each period remains unchanged and agrees with the final RIN lodged for each year.

During 2010 there was a minor reallocation of $592.97k between Employee Entitlement provisions and Self Insurance provision which differed from the audited accounts. The reallocation related to a minor workers compensation discrepancy. The reallocation was required to ensure consistency year on year.

During the 2010 year the NSW Government announced it had entered into a contract for the sale of the Retail business. Based on this all Regulated Retail information was included in Other Unregulated.

All information included in the 2013/14 Forecast was sourced from Quarter 2 Forecasts in TM1. The forecast balance sheet was only prepared at a sub category level with amounts allocated to only one expense element within the sub category. To ensure consistency with prior years, an assumption was made to separate the one expense element into the relevant provisions required. The assumption was based on past trends and expected positions as at June 2014.

The allocation of the total provisions into Standard Control for 2013/14 closing balance was based on the percentage allocations of opex and labour for 2013/14 from the Reg Accounts cube in TM1 split between standard control, alternate control and other unregulated.

An estimate had to be made for employee benefits, self insurance and a portion of other in regards to the "increases to the provision" and "amounts used" as only the opening and closing balances were available. The estimate was to use 2012/13 "amounts used" plus 2.5%, with the balancing item in "increases in provisions".

The methodology used to populate *table 2.13.2 Allocation of movement in total provisions* was all opex related with the exception of the Defined Benefits Superannuation provision which had amounts allocated directly to retained earnings. The amount allocated to retained earnings was the standard control allocation of actuarial gains and losses on the defined benefits superannuation scheme for the periods 2008 – 2013 and actuarial gains and losses plus actual return on fund assets less interest income for 2013/14 as per revised AASB 119 Employee Benefits accounting standard. The 2013/14 movement was based on the 6 months to 31 December 2013 actuarial assessment performed by Mercer.

Use of estimated information

Endeavour Energy has used estimated information when determining a profit & loss split of Regulated Distribution Network into Standard Control Services, Alternate Control Services and Other Excluded Services for the periods 2008 – 2010. The profit & loss was required to allocate the Dividend provision based on profit after tax into Standard Control Services. Dividend are paid in the following year, therefore the liabilities paid from provision will always equate to the opening balance.

Included in Other in 2009 was a capitalisation threshold provision which was paid and reversed during 2009. The closing balance of the capitalisation threshold as at June 2009 was zero. The allocation driver used to determine the paid and reversed amounts were the same used in 2008. Any impact of a change in allocation driver between 2008 and 2009 was immaterial.

Reliability of information

All information provided represents actual information extracted from RIN work papers which reconcile to reported figures in previous audited RIN's.

Worksheet 2.14 – Forecast price changes

2.14.1 Forecast labour and materials price changes

Compliance with requirements of the notice

The data presented in table 2.14 is consistent with the requirements of the Reset RIN, in particular the RIN requires;

- Labour & material price changes assumed by Endeavour energy in estimating forecast capex & opex proposals.
- Provision of models used to derive price changes, copies of EBA's and
- the price changes are expressed in percentage year on year real terms.

Source of information

Data provided in RIN Template 2.14.1 contains historic & forecast labour & material price changes. This data was extracted from actual records (such as previous EBA agreements), ABS data (for CPI) and a report and accompanying model provided to Endeavour Energy by Independent Economics and Competition Economists Group. See Attachments 0.04, 0.05 and 5.20 to Endeavour Energy's regulatory proposal

Sources of information by type include;

Labour Costs
- Endeavour energy EBA
- Independent Economics Analysis & Report (Based on ABS Data)

Material Costs
- Construction Costs:
  - Construction Forecasting Council Forecasts (Based on ABS Data)
- Copper & Aluminium Prices
  - LME Data (Bloomberg)
  - Consensus Economics Forecasts
- Steel Prices
  - MEPS Asia CBN Data (Bloomberg)
  - Consensus Economics Forecasts
- Oil
  - Assumed constant real $US prices (AER approach)
  - US Department of Energy (Not used for forecast)
  - Consensus Economics Forecasts

Australian Dollar Exchange Rate
- Forward Market Rates (Bloomberg)

CPI
- CPI to deflate Labour Costs to real (ABS data)
- CPI to deflate Commodity Futures (RBA forecasts).

Methodology and assumptions

Methodology is outlined in the following reports;
- Escalation factors affecting expenditure forecasts, December 2013 - CEG Asia Pacific

- Labour cost escalators for NSW, the ACT and Tasmania, February 2014 – Independent Economics

These price changes were provided for the forecast regulatory control period. For the current regulatory control period the same indices and formula were used to determine the actual price changes.

Use of estimated information

Historical information is based on actual information (i.e. EBA data, Commodity market prices, Exchange rates and ABS Data).

Reliability of information

Worksheet 2.15 – Commercial insurance and self-insurance

2.15.2 Insurance premium - property

Compliance with requirements of the notice

As required by paragraph 11.2(b) of Schedule 1 of the RIN, the information provided in tables 2.15.2 provides more detailed information regarding total property premiums only. As required the total property premiums forecast in table 2.15.2 equals the sum of the premium forecasts classed as property insurance in table 2.15.1.

Source of information

A report by Endeavour Energy's insurance brokers, Aon and Marsh was used as the basis for the information provided.

Methodology and assumptions

Endeavour Energy has forecast 2014-2019 premiums with its brokers, Aon and Marsh, providing their rate/premium estimates of the cyclical insurance market using their 2013-14 budget premiums as a base. Where appropriate, Endeavour Energy has then increased property values to account for assets under construction coming on stream. In addition to CPI, Bushfire risk continues as a major issue for global insurers. Black Saturday and more recent Australian fires, particularly the October 2013 Blue Mountain bushfires, remain fresh in insurers' minds and could lead to significantly increased premiums.

The assumptions made by Endeavour Energy are:
- No major bushfire losses in Australia;
- Claims generally consistent with past history;
- Deductibles remaining static;
- No significant change in risk profile;
- No limit changes;
- No global events which may impact the insurance market generally; and
- No changes to stamp duty or other government imposts.

Use of estimated information

No estimated information was used.

Reliability of information

2.15.3 Insurance premium - liability

Compliance with requirements of the notice

As required by paragraph 11.2(b) of Schedule 1 of the RIN, the information provided in tables 2.15.3 provides more detailed information regarding total liability premiums only.

Source of information

A report by Endeavour Energy's insurance brokers, Aon and Marsh was used as the basis for the information provided.

Methodology and assumptions

In this section we need to explain the methodology Endeavour Energy applied to provide the required information, including any assumptions Endeavour Energy made.

Endeavour Energy has forecast 2014-2019 premiums with its brokers, Aon and Marsh, providing their rate/premium estimates of the cyclical insurance market using their 2013-14 budget premiums as a base. Where appropriate, Endeavour Energy has then increased property values to account for assets under construction coming on stream. In addition to CPI, Bushfire risk continues as a major issue for global insurers. Black Saturday and more recent Australian fires, particularly the October 2013 Blue Mountain bushfires, remain fresh in insurers' minds and could lead to significantly increased premiums.

The assumptions made by Endeavour Energy are:
- No major bushfire losses in Australia;
- Claims generally consistent with past history;
- Deductibles remaining static;
- No significant change in risk profile;
- No limit changes;
- No global events which may impact the insurance market generally; and
- No changes to stamp duty or other government imposts.

Use of estimated information

No estimated information was used.

Reliability of information

Worksheet 2.17 – Step changes

2.17.1 Forecast opex step changes for standard control services

Compliance with requirements of the notice

The data presented in worksheet 2.17 is consistent with the requirements of the Reset RIN. In particular:

- Total opex and capex step changes expenditure split into Standard Control Services in accordance with the definitions of these categories.

- Endeavour Energy does not own any dual function assets, so tables 2.17.3 and 2.17.4 are not applicable.

- The step change expenditure represents the expenditure that has been incurred in the *current regulatory control period* relative to expenditure previously approved by the AER in addition to the forecast expected to be incurred in each year of the *forthcoming regulatory control period*.

- The table below provides further detail on the step changes in table 2.17.1:

Step Change	Description	When the change occurred or will occur	Driver of the step change	Recurrent in nature?
Retail Dis-synergy Costs	The sale of the retail business resulted in the regulated network services being allocated a greater share of the (reduced) residual corporate and overhead costs. As the 2012-13 financial year was the last year in which we provided any retail support services, the 2013-14 financial year is the first year in which these dis-synergy costs are fully crystallised.	Commenced 1 March 2011	Sale of the Business	Yes
Investment Prioritisation Redundancies	This is a reflection of several efficiency initiatives and a return to a more sustainable level of investment in our network creating a step up in our operating expenditure compared to our base year.	Post 30 June 2015	Efficiency initiatives	No – 2015/16 and 2016/17 only.
Vegetation Management	The step change in vegetation management costs is due to observed increases in contract conformance costs consistent with our ongoing focus on the achievement of required program compliance for this critical risk management function. We have experienced additional cost movements in market delivered contracts.	Ongoing	Increased contract conformance and market delivered contract costs.	Yes
ACS Transfer from SCS	Type 5 and 6 metering services and ancillary network services (formerly miscellaneous and monopoly) have been reclassified as alternative control	1 July 2015	Regulatory Change	Yes

Step Change	Description	When the change occurred or will occur	Driver of the step change	Recurrent in nature?
	services for the 2014-19 period. Accordingly, we have removed the cost related to these services from our standard control operating expenditure forecast for the 2014-19 period			

- The table below provides further detail on the step changes in table 2.17.2:

Step Change	Description	When the change occurred or will occur	Driver of the step change	Recurrent in nature?
Labour reductions	Initiatives to improve delivery efficiency resulted in better alignment of workforce skills with the requirements of the capital expenditure program. This resulted in some savings in labour costs.	From 2011 to 2014	Efficiency initiatives	No
Design / construction standards	The establishment of Networks NSW provides an opportunity to establish commonality across the three businesses in design and construction standards that is intended to result in cost reductions through improved practices and more efficient standards.	From 1 July 2014	Efficiency initiatives	Yes
NSW Licence conditions changes	The removal of mandated supply security requirements from our operating licence conditions	1 July 2014	Regulatory change	No
Reduction in peak demand	Reductions in peak demand over forecast demand due to the onset of the GFC resulted in a reassessment of the need to augment the network and a subsequent cancellation / deferral of some growth capex.	From 1 July 2009	Reduction in demand	No
Greenfield development	The requirement to establish significant new infrastructure to supply greenfield development areas is expected to commence in 2017 based on the best currently available information. This will represent a step increase on immediately prior expenditure levels.	1 July 2017	Growth	No
Reassessed asset renewal needs	Revaluation of asset condition enabled the deferral of some asset renewal expenditure to later in the regulatory control period.	1 July 2009 – 30 June 2014	Asset condition	No
Land & buildings	The completion of the Springhill Field Service Centre by 1 July 2015 will result in land and buildings capex reverting to lower, historic levels	1 July 2015	Completion of project	No
Non-material	A variety of minor changes resulting in	Commenced	Various	Yes

Step Change	Description	When the change occurred or will occur	Driver of the step change	Recurrent in nature?
changes	differences between actual expenditure and the AER allowance (current period) or year on year changes (forthcoming period).	1 July 2009		

Source of information

Opex

Set out in the table below is the specific cubes used to obtain the required information for table 2.17.1, along with a description in relation to the use of the cubes by Endeavour Energy:

Table	TM1 Cube	Description
2.17.1	Reg Accounts cube	The Reg Accounts cube is used by Endeavour Energy to store and report the Opex into the service categories (i.e. Standard Control, Alternate Control and Unregulated categories) at the account code level. It is the primary tool used to allocate opex in accordance with Endeavour Energy's approved Cost Allocation Method. Standard control opex data was extracted from the TM1 Reg Accounts cube at the account code level (N level org units) for each financial year for the category called "Regulated Network $".
2.17.1	PNL cube	The PNL cube in TM1 is used by Endeavour Energy for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes. The PNL cube contains General Ledger information sourced from our Ellipse (ERP System) based on Endeavour Energy's chart of accounts.
2.17.1	AER Dollars by Account cube	The AER Dollars by Account cube in TM1 is used by Endeavour Energy for capturing and reporting on the forecast opex financials for the 2014-19 AER period.

Capex

Table	TM1 Cube	Description
2.17.2	PNL cube	The PNL cube in TM1 is used by Endeavour Energy for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes. The PNL cube contains General Ledger information sourced from our Ellipse (ERP System) based on Endeavour Energy's chart of accounts.
2.17.2	Supporting capex worksheets	Supporting capex worksheets provide expenditure detail by project and program.

Methodology and assumptions

Table	Methodology	Assumptions
2.17.1	1/ Extract the Net Retail dis-synergy costs (primarily corporate overheads) that have historically been split between the Network and Retail business, for which the Network business will absorb the full amount once Retail was sold. A "marginal approach" has been used to identify incremental costs and estimate costs that will no longer be required in a Network only business, and are therefore stranded.	Nil
	2/ Extract the Investment Prioritisation Redundancies by each of the RIN categories from the AER Dollars by Account cube in TM1	
	3/ Estimate the Vegetation management step change year by year by using the Benchmarking RIN table (3.1.1) as the baseline and adding the future years forecast together, then assessing the movement each year.	
	4/ Extract the Type 5 and 6 metering services and ancillary network services from the AER Dollars by Account cube in TM1.	
2.17.2	Annual step changes were considered at the level of capex driver for both system and non-system capex. The total step change for each year was determined as the difference between the actual and the AER allowance for the current regulatory control period and the year on year change for the forthcoming regulatory control period.	
	Significant changes in each driver were detailed based on known deviations from the expenditure profile in our 2009-14 determination (current period).	
	Significant year on year changes in the forthcoming regulatory control period in each driver were detailed based on changes incorporated in the proposed expenditure plans.	Growth in demand in greenfield development areas will exhaust interim supply arrangements by 2018 and an increase in growth related expenditure will be required to establish infrastructure to supply this demand. All the reduction in land and buildings expenditure forecast in 2015/16 is due to the completion of Springhill FSC the previous year.
	The remainder of the total step change in each year was assigned to the category of non-material changes.	

Use of estimated information

All information provided for the tables in section 2.17 consist of some actual information with significant amount of estimation or judgement applied to allocate the information required into the AER templates.

Reliability of information

All historical information provided represents Actual Information extracted from Endeavour Energy's reporting systems adjusted based on estimation or judgement but is considered to be reliable. Future forecast information is considered to be estimated.

2.17.3 Forecast opex step changes for dual function assets

Compliance with requirements of the notice

Endeavour Energy does not have any dual function assets and hence does not need to complete this table in the Excel workbook.

2.17.4 Forecast capex step changes for dual function assets

Compliance with requirements of the notice

Endeavour Energy does not have any dual function assets and hence does not need to complete this table in the Excel workbook.

Worksheet 4.1 – Public lighting

4.1.1 Public lighting descriptor metrics current year

Compliance with requirements of the notice

The data provided for "Current Population of Lights" (Table 4.1.1) has been reported as of the 30th June 2013 to represent the current year (2012/13). The light types are broken down into individual light types (Mercury, Compact Fluorescent, T5 fluorescent etc.) and wattages of each light type in use.

Source of information

The data is extracted from predefined query developed for the purpose of extracting this and similar data in a controlled and consistent manner (established by Endeavour Energy's IT department) using the organisation's COGNOS 8 program. COGNOS 8 extracts this data from Ellipse (the organisations asset management database).

Methodology and assumptions

This data can be extracted for historical periods. For the purpose of this submission, the data is extracted for 30th June 2013 for considering it as current year.

Use of estimated information

Estimation was not necessary as data is extracted for the date 30 June 2013. Assets shared between two councils appear twice in the reporting query used and are identified in the "Bill Percent" field by a 50% value. These assets have been identified from the query and are not double counted in the volumes provided.

Reliability of information

The data within COGNOS 8 / Ellipse is considered reliable and is Endeavour Energy's main source of asset / financial data. Historical data is frequently applied for budgeting and forecasting.

4.1.2 Public lighting descriptor metrics annually

Compliance with requirements of the notice

The data provided under "Descriptor Metrics Annually" is in line with the data format provided.

Where data is not available in the reporting format requested this is clearly documented in the BoP.

Source of information

The information with "Descriptor Metrics Annually" is based upon Endeavour Energy projects / costs only and does not include any projects associated with Accredited Service Providers. The data was obtained from the following sources for years 2008/09 to 2012/13:

Light Installation volume data

The data was extracted from predefined query developed for the purpose of extracting this and similar data in a controlled and consistent manner (established by Endeavour Energy's IT department) using the organisation's COGNOS 8 program. COGNOS 8 extracts this data from Ellipse (the organisations asset management database).

Values for "Number of Poles Installed" have been identified as zero as the number of poles installed purely for streetlight by Endeavour Energy is already incorporated in the Major Road Light Installation Volume and Minor Road Light Installation Volume.

Light Installation Total Cost

"Total Cost" associated with Light Installation have been sourced from Endeavour Energy's Finance and Compliance department from a report titled "Street Lighting 0809 to 1314" supplied on 15/04/2014 by Michael Ware (AER Project Analyst at Endeavour Energy).

Light Replacement Total Cost comprises of Condition based maintenance (RC) and Inspection (RI : Patrol / Routine column inspection). The Light Maintenance Total Cost comprises of Fault and Emergency (RF) and Preventive maintenance comprising of Bulk Lamp Replacement (RP). This data is also sourced from Endeavour Energy's Finance and Compliance department from a report titled "Street Lighting 0809 to 1314" supplied on 15/04/2014 by Michael Ware (AER Project Analyst at Endeavour Energy).

Future projections:

OPEX is forecast at the category level such as street lighting that are recurring activities based on total network size. 2012/13 financial year (inclusive of savings and reforms) is the starting base year in developing the 2014/15-2018/19 regulatory period forecast. 2012/13 is the fourth year of the current regulatory period and is used because it is the latest actual OPEX data available for the complete year at the time of preparing the forecast. The base step trend method involves the selection of 2012/13 as the nominated base year which is escalated and adjusted as appropriate to derive a forecast that best reflects the OPEX requirements of the forthcoming period.

The base year method uses the following inputs to develop the forecast OPEX:
- The base year OPEX, adjusted to remove one-off or non-recurrent costs;
- Forecast saving initiatives from Endeavour Energy's cost reduction strategies;
- Forecast savings initiatives from Networks NSW efficiency programs;
- Impact of change factors on forecast costs; and

- Real cost escalators.

CAPEX expenditure is forecast to achieve the objectives outlined in the Endeavour Energy's network strategy document plan. The Strategic Asset Management Plan is the key tool used by Endeavour Energy to ensure that the individual program expenditures are integrated in such a way as to obtain the maximum network benefit in an efficient and sustainable manner. The development of the individual asset management plans involves identifying and forecasting required capital works based on network need. Investment needs across the network are identified using detailed engineering analysis of the network, current asset and network condition reports, spatial demand forecasts, regulatory obligations and requirements and identified customer concerns. Once a particular network constraint is identified, project options to address the network need are developed. At this stage a number of options including non-network alternatives and OPEX substitution possibilities are considered. Forecast costs are then calculated for each project option. For the majority of CAPEX categories, a 'bottom up' method is employed to derive the forecast CAPEX. The bottom up method utilizes:

- Historical unit costs
- Volumes based on historical experience and network need
- Current labour and contractor rates
- Current material and equipment costs.

These financial values include both street lighting costs associated with "Light Installation" as well as costs associated with "Light Replacement" for columns that have been replaced. The figures available could not be separated as requested in the table format.

Pole numbers:
The number of poles installed includes steel columns and dedicated wood poles for street light.

Light Replacement volume data:
Volume data for light replacements have been divided into four categories:
COL – Column Replacement (indicates complete new column replaced)
OMS – Outage Management System (Fault & Emergency)
BC – Bulk Change
LC – Luminaire Replacement

For the purpose of compliance, the data under Light Replacement Volume and Light Maintenance Volume have been added as follows:
Light Replacement Volume = COL + OMS + LC
Light Maintenance Volume= OMS + BC

COL data was obtained from Network Data & Performance using the COGNOS 8 reporting program. The data extracted by COGNOS 8 is taken from Ellipse (the organisations asset management database).

The OMS data was obtained from the organisations Outage Management System to identify the number of fault and emergency projects associated with streetlights.

The LC data was obtained from Endeavour Energy's Street Light Contract Manager on 4/4/2014. No verifiable data is available for the 2008/09 and 2009/10 financial years.

LC data is not available in a major / minor road format and a ratio (of 72% Major, 28% Minor) has been applied to obtain a split. Source of the ratio is documented in "Methodology and assumptions".

Light Replacement Total Cost:
The source of this data is as described in "Light Installation Total Cost".

Light Maintenance Volume:
The source of this data is as described in "Light Replacement volume data". Number of poles installed is already covered in the Installation and Replacement data above. The numbers given under Maintenance refer to the Light Columns inspected during the year.

The BC data was obtained from Endeavour Energy's Street Light Contract Manager on 4/4/2014. No verifiable data is available for the 2008/09 and 2009/10 financial years. BC data is not available in a major / minor road format and a ratio (of 72% Major, 28% Minor) has been applied to obtain a split. Source of the ratio is documented in "Methodology and assumptions".

Light Maintenance Total Cost:
The source of this data is as described in "Light Installation Total Cost".

Quality of Supply:
Quality of Supply data including "Mean days to rectify/replace public lighting assets" and "Volume of Customer Complaints" was extracted from a predefined query developed for the purpose of extracting this and similar data in a controlled and consistent manner (established by Endeavour energy's IT department) using the organisation's COGNOS 8 program. COGNOS 8 extracts this data from Ellipse (the organisations asset management database).

"Volume of GSL Breaches" data obtained from Endeavour Energy's Customer Interaction Centre who maintains a report of each GSL Breach which is stored in the organisation eDOCs system for control and security. Total GSL breaches are based on all customer complaints.
"GSL payments" data is based on "Volume of GSL Breaches" multiplied by $15.00.

Methodology and assumptions

Forecast volume data for "Light Installation", "Light Replacement" and "Light Maintenance" have been extrapolated forward using the average values (for each category/row) for the last three years (since data was not available for 2008/09 and 2009/10) to populate data for 2013/14 to 2018/19.

Forecast total costs associated with "Light Installation" are based on actual forecasts provided by the Finance and Compliance department as stated for the source of information for "Light Installation Total Cost".

Forecast total costs associated with "Light Replacement" and "Light Maintenance" have been increased from 2012/13 using CPI values (2.5%) and real labour cost escalators obtained from Endeavour Energy's Finance & Compliance branch on the 28/03/2014.

Forecast data for Quality of Supply including "Mean days to rectify/replace public lighting assets" and "Volume of GSL Breaches" have been extrapolated forward using the average values (for each category/row) for the last five years to populate data for 2013/14 to 2018/19. Forecast data for "Volume of Customer Complaints" has been extrapolated for 2013/14 on a prorata basis to June 2014 (actual data for the period 01.07.2013 to 31.03.2014 is used to calculate the prorata for the year 01.07.2013 to 30.06.2014). Data for future years from 2014/15 to 2018/19 is projected on the basis of the average data of the previous six years including the prorata data for 2013/14.

"GSL payment" data is based on "Volume of GSL Breaches" multiplied by $15.00.

The ratio used to divide BC data into major and minor roads is based on the number of lanterns smaller / larger than 150W. This ratio was calculated for each financial year between 2008/09 and 2012/13 and the average taken. The final ratio used was 72:28 for minor and major roads respectively.

Use of estimated information

All historical data to 2012/13 is based on actuals, forecasted data is based on the information provided above under Methodology and assumptions. The LED light source is an approved item yet does not show in the table 4.1.1 for the year 2012/13 as it was not approved by 30.06.2013.

Reliability of information

The information within COGNOS 8 / Ellipse is considered reliable and is Endeavour Energy's main source of asset / financial data. Historical data is frequently applied for budgeting and forecasting. The LED light source is an approved item yet does not show in the table 4.1.1 for the year 2012/13 as it was not an approved product by 30.06.2013.

4.1.3 Public lighting cost metrics

Compliance with requirements of the notice

The data provided under Cost Metrics is consistent with the requirements of this Notice. Assumptions, if any, are explained in detail below.

Source of information

"Average Cost" data for the Installation of Lights on major / minor roads for the 2013/14 financial year was obtained from Ellipse directly for each of the projects used in the "Average Unit Cost" values provided.

"Average Cost" data for the replacement and maintenance of street lights on major / minor roads was obtained from Endeavour Energy's Street Light Contract Manager on the 4/4/2014. This data was sourced from the Streetlight Refurbishment Report Rate (approved by finance). Material unit prices have been supplied by procurement for each of the individual light types shown.

Methodology and assumptions

Data for the "Average Unit Costs" for the installation of Street Lightings on Major and Minor roads has been obtained from a random sample of internal Street Lighting projects. The sample of projects have been used to calculate average costs for the 2013/14 financial year in the following three categories "Installation of Columns", "Installation of a Dedicated Wood Pole" and "Installation of Street Lighting on an existing wood pole".

The following projects / sample sizes have been used to develop an average cost per column / pole:

Road Type	Light Type	Project #
Minor Road	Column	SLNP0341
		SLNL0332
	Dedicated Pole	SLNL0366
	Network Pole	SLN0371
		SLNA0101
		SLNM0244
		SLNL0374
		SLNL0369
		SLNA0098
Major Road	Column	SLNP0360
		SLNA0092
		SLNA0102
		SLNF0021
		SLNF0019
	Dedicated Pole	SLN0353
	Network Pole	SLNM0228
		SLNM0226

Sample sizes vary between "Light Type" / "Road Type" based on the availability of project information and the data for the "Average Unit Costs" for the installation of Street Lightings on Major and Minor roads.

Use of estimated information

Data for all other years (historical and forecasted) has been calculated based on the following CPI data:

Years	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
CPI	N/A	4.35%	1.82%	2.85%	3.39%	1.76%			2.50%		

Reliability of information

The data within COGNOS 8 / Ellipse is considered reliable and is Endeavour Energy's main source of asset / financial data. Historical data is frequently applied for budgeting and forecasting.

Worksheet 4.2 – Metering

4.2.1 Metering descriptor metrics

Compliance with requirements of the notice

The data presented in table 4.2.1 is consistent with the principles and requirements set out in Appendix E of the Reset RIN.

Source of information

The volume of meters including key parameters such as number of phases and connection type was obtained from Endeavour Energy's meter asset management system (Banner) for the reporting period 2013/14. Historic volumes are based on a de-escalation of 2013/14 meter volumes based on the growth of customer numbers over the current regulatory control period.

Methodology and assumptions

Meter volumes for 2013/14 are based on actual volumes as at March 2014. Historic volumes are based on a de-escalation of 2013/14 meter volumes based on the growth of customer numbers over the current regulatory control period.

Important notes in relation to the interpretation of table 4.2.1:

- Type 4 meters disclosed in table 4.2.1 represent non-contestable franchise market meters with communication equipment. Endeavour Energy does not have any Type 5 manually read interval meters as all meters in the Type 5 energy volume range have had communications equipment installed (and are read remotely) and are therefore defined as Type 4 meters.

- The de-escalation factors used to calculate historic meter volumes is based on actual NMIs at the end of each financial year. This was obtained from the Banner system and the difference in customer volume for each financial year was converted to a percentage to represent the de-escalation factor.

- Determining key parameters such as number of phases and connection type for historic volumes is based on the ratio of the volume for the reporting period 2013/14.

Use of estimated information

While assumptions are applied to estimate historic meter volumes (as outlined above), the data presented in table 4.2.1 represents actual information as defined in the RIN. Specifically, historic meter volumes are materially dependent on 2012/13 meter volumes and historic customer numbers recorded in Endeavour Energy's historical accounting records. In addition, as there is a high correlation between NMIs and the volume of meters, there is no valid alternative to estimate historic meter volumes (other than the method used) which could lead to a materially different presentation.

Reliability of information

Notwithstanding the assumptions applied to estimate historic meter volumes (as outlined above), the information provided represents Actual Information as defined in the RIN. As a result, the information contained in table 4.2.1 is considered to be reliable.

4.2.2 Metering cost metrics

4.2.2 Cost Metrics (Expenditure)

Compliance with requirements of the notice

The data presented in table 4.2.2 (expenditure) is consistent with the principles and requirements set out in Appendix E of the Reset RIN. In particular:

- The data presented in table 4.2.2 (expenditure) reflects expenditure relating to metering services in accordance with the definitions provided in Appendix F of the Reset RIN.

- Forecast operating and replacement capital expenditure for 2014/15 to 2018/19 reconciles to internal planning models used in generating Endeavour Energy's proposed meter service charges and revenue requirements for metering services. Specifically, forecast operating and replacement capital expenditure reconciles to annual recoverable costs presented in the Metering Services Charge model provided as Attachment 0.17 to the Substantive Regulatory Proposal.

  The Metering Service Charge model is used by Endeavour Energy to calculate charges, and an associated revenue requirement, for metering services classified as alternative control services for the 2015-19 regulatory period in accordance with the AER's Framework & Approach Paper – March 2013. Therefore, in order to present information on a consistent basis for the 2008/09 to 2018/19 period, the historic and forecast expenditure presented in this template reflects expenditure associated with metering services classified as alternative control services for the 2015-19 regulatory period (i.e. type 5 and 6 metering provision, maintenance, reading and data services).

- Endeavour Energy has not distinguished expenditure for metering services between standard or alternative control services. It is noted that for Endeavour Energy, metering services are classified as standard control services for the 2009-14 regulatory period and alternative control services for the 2015-19 regulatory period.

- Endeavour Energy has not distinguished expenditure for metering services as either capital expenditure or operating expenditure. However, the service sub-categories required in table 4.2.2 (expenditure) inherently split expenditure between operating and capital, with meter purchase, new meter installation, meter replacement, IT infrastructure capex and communications infrastructure capex all capital related activities and the remainder operating related activities.

- Endeavour Energy has not reported data in relation to metering services which have been classified as contestable by the AER and has only reported data for non-contestable / regulated metering services (including work performed by third parties on behalf of Endeavour Energy). It is noted that while type 4 meters are classified as contestable in NSW, Endeavour Energy has reported expenditure related to type 4 meters. This is because Endeavour Energy has installed communications equipment on all of their type 5 meters[1], converting them into remotely read interval meters with communications functionality, and therefore type 4 meters by definition. As a result, the expenditure presented for type 4 meters refers to type 5 meters with communications functionality (or non-contestable type 4 meters).

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[1] Given the small number of type 5 meters in Endeavour Energy's network area, it was decided that installing communications equipment on each of these meters (and therefore converting them into type 4 meters) represented the most cost effective method of reading the meter data.

Source of information

Historic expenditure relating to metering services was extracted from Endeavour Energy's general ledger, which is contained in an IT system called Ellipse. Ellipse contains operating and capital work orders / projects which are reporting tools used to capture expenditure associated with a particular task.

Methodology and assumptions

The method applied to report historic metering services expenditure in accordance with the requirements of the RIN can be described in 5 broad steps as set out below:

1. Calculate historic capital expenditure related to regulated meters only (i.e. excluding relays and load control);
2. Calculate historic direct operating expenditure associated with scheduled meter reading;
3. Calculate historic direct operating expenditure associated with metering services (excluding scheduled meter reading);
4. Estimate historic network and corporate overheads associated with metering services; and
5. Split historic expenditure (operating and capital) between meter types 4 and 6.

1. Calculate historic capital expenditure related to regulated meters only (i.e. excluding relays and load control)

Historic metering capital expenditure was extracted from the general ledger by project. These projects included expenditure related to both regulated meters and load control equipment. For the purposes of populating table 4.2.2, only capital expenditure related to metering equipment is relevant, as activities related to load control remain classified as standard control for the 2015-19 regulatory period. Specific projects related to the purchase of meters for new installations, meter replacement and the purchase of associated test equipment were identified. In addition, as there exists only one project for capitalised labour related to meters and load control replacement, the meter related component of this project was calculated based on the proportion of meter and load control material costs.

The result represents capital expenditure related to regulated meters only and each project is mapped to a specific metering service sub-category in table 4.2.2.

2. Calculate historic direct operating expenditure associated with scheduled meter reading

Scheduled meter reading activities are performed by the Market Operations branch in Endeavour Energy. In order to calculate the direct operating expenditure associated with scheduled meter reading, service order volumes and task time-to-complete estimates provided by the Market Operations Manager were used to split total 2012/13 Market Operations branch operating expenditure between its relevant functions. The proportion of scheduled meter reading expenditure to total Market Operations branch operating expenditure for 2012/13 was applied to the 2008/09 to 2011/12 period to estimate scheduled meter reading expenditure for the historic period. This assumption was applied as total Market Operations branch operating expenditure did not fluctuate materially over the current regulatory period and the proportion of work performed is believed to have remained consistent over the period.

3. Calculate historic direct operating expenditure associated with metering services (excluding scheduled meter reading)

All other metering services (excluding scheduled meter reading activities) are performed by the Metering Information branch in Endeavour Energy. In order to calculate the direct operating

expenditure associated with the metering services performed by the Metering Information branch, the following steps were performed:

i. Operating expenditure for the 2008/09 to 2012/13 period was extracted from the general ledger for the Metering Information branch at the work order level;

ii. Based on the work order description and the GL account code assigned to the work order, those work orders related to regulated metering were identified, along with Metering Information branch overhead, other standard control activities and contestable metering. For those work orders identified as relating to regulated metering, Endeavour Energy allocated the work order to specific metering service sub-categories based on the work order description and GL account code, in accordance with the categories required in table 4.2.2 of the Reset RIN; and

iii. Expenditure identified as Metering Information branch overhead was allocated to regulated metering service sub-categories based on the proportion of regulated metering services to total Metering Information branch direct costs.

The above steps resulted in the identification of Metering Information branch expenditure related to regulated metering and the disaggregation of this operating expenditure into the metering service sub-categories required by table 4.2.2.

Endeavour Energy has not reported any expenditure or volumes associated with type 6 special meter reading in table 4.2.2. Given special meter reading is classified as an Ancillary Network Service in the 2015-19 regulatory period (in accordance with the AERs Framework & Approach Paper – March 2013), historic expenditure and volumes associated with type 6 special meter reading have been captured in tables 4.3 and 4.4 (fee-based and quoted services respectively) to reflect the classification for the forthcoming regulatory control period. Type 4 special meter reading was only required during the transition of Endeavour Energy's type 5 meters to type 4 meters (as explained above), and therefore no type 4 special meter reading expenditure is forecast for the forthcoming regulatory control period.

4. Estimate historic network and corporate overheads associated with metering services

The operating expenditure calculated in step 2 and 3 above only relates to direct operating expenditure. In order to allocate a reasonable portion of network and corporate overheads to each metering service for the historic period, the average network and corporate overhead factor derived from the Cost Allocation Methodology (CAM) model for the 2015-19 regulatory period (specific to regulated metering services) was applied to direct costs for the 2008/09 to 2012/13 period. This assumes that the ratio of direct costs to costs inclusive of network and corporate overheads for metering services as calculated by the CAM model for the 2015-19 regulatory period, reflects the actual consumption of network and corporate overheads in the historic period. This assumption has been applied as the level of network and corporate overheads as a proportion of company direct costs has not materially changed over time and the regulated metering activity as a whole has not changed significantly during the current regulatory control period.

This resulted in metering service operating expenditure at the sub-category level inclusive of network and corporate overheads.

5. Split historic expenditure (operating and capital) between meter types 4 and 6

Historic expenditure was split between meter types 4 and 6 based on the ratio of type 4 and 6 meters from table 4.2.1.

Use of estimated information

The historic expenditure reported in table 4.2.2 is materially dependent on information recorded in Endeavour Energy's historical accounting records. In addition, although a number of assumptions have been applied to calculate and report historic metering services expenditure in accordance with metering service sub-categories (as outlined above), there are no valid alternatives to the assumptions applied which could lead to a materially different presentation.

As a result, the historic expenditure information presented in table 4.2.2 represents Actual Information as defined in the Reset RIN.

Material accounting policy changes

Endeavour Energy have not undertaken any material changes in accounting policies which would impact the expenditure data contained in table 4.2.2.

Reliability of information

The expenditure information contained in table 4.2.2 represents Actual Information as defined in the Reset RIN. While a number of assumptions have been applied in order to report the figures in accordance with the requirements of the Reset RIN, Endeavour Energy considers these assumptions to be reasonable and result in reliable information.

Table 4.2.2 Cost Metrics (Volumes)

Compliance with requirements of the notice

The data presented in table 4.2.2 (volumes) is consistent with the principles and requirements set out in Appendix E of the Reset RIN.

Source of information

The volume of metering services was obtained from Endeavour Energy's metering work management system (Banner) for the reporting period 2008/09 to 2012/13.

Methodology and assumptions

The total volume for the meter purchase subcategory for the reporting period 2008/09 to 2012/13 is based on actual meter installation volumes from Banner.

The total volume for the meter testing, meter investigation, special meter reading, meter replacement and meter maintenance subcategories for the reporting period 2008/09 to 2012/13 is based on actual service orders from Banner.

The total volume for the scheduled meter reading subcategory for the reporting period 2008/09 to 2012/13 is based on the application of a ratio of the number of reads per customer per annum (derived from actual data) to average customer numbers for the period. This resulted in the estimation of schedule meter reads for the historic period.

The total volume for the remote meter reading subcategory for the reporting period 2008/09 to 2012/13 is based on actual customers from Banner.

Determining historic volumes by meter type is based on actual data for the meter purchase subcategory, however is estimated for all other subcategories based on the historic proportion of all installed type 4 and 6 meters.

Important notes in relation to the interpretation of table 4.2.2 (volumes):

- Type 4 meters disclosed in table 4.2.2 represent non-contestable franchise market meters with communication equipment. Endeavour Energy does not have any Type 5 manually read interval meters as all meters in the Type 5 energy volume range have had communications equipment installed (and are read remotely) and are therefore defined as Type 4 meters.

- For the meter purchase subcategory the historical metering services is based on when the meter is installed.

- The new meter installation subcategory is nil for type 6 meters because this type of service is performed by ASPs therefore no volume is included for Endeavour Energy.

- The new meter installation subcategory is nil for type 4 meters because type 4 meters are not installed at new metering installations, instead they are meter changes from type 6 to type 4 once the consumption breaches the type 6 consumption threshold.

- Between 2008/09 and 2012/13 the volume of meters purchased is 308,432. These meters are used as follow: 67,175 new meter installations (see table 4.2.1) and 243,247 replaced meters (the sum of meter replacement and meter maintenance service orders multiplied by a customer

to meter ratio of 1.77112 - the customer to meter ratio is obtained by comparing customer and meter volumes).

Use of estimated information

The historic volume data reported in table 4.2.2 is materially dependent on information recorded in Endeavour Energy's historical accounting records. In addition, although a number of assumptions have been applied to calculate and report historic metering services volumes in accordance with metering service sub-categories (as outlined above), there are no valid alternatives to the assumptions applied which could lead to a materially different presentation.

As a result, the historic expenditure information presented in table 4.2.2 represents Actual Information as defined in the Reset RIN.

Reliability of information

The volume information contained in table 4.2.2 represents Actual Information as defined in the Reset RIN. While a number of assumptions have been applied in order to report the figures in accordance with the requirements of the Reset RIN, Endeavour Energy considers these assumptions to be reasonable and result in reliable information.

Worksheet 4.3 – Ancillary services – Fee based services

4.3.1 Cost metrics for fee based services and 4.4.1 Cost metrics for fee based services

Compliance with requirements of the notice

The data presented in tables 4.3.1 and 4.4.1 is consistent with the principles and requirements set out in Appendix E of the Reset RIN. In particular:

- The data presented in tables 4.3.1 and 4.4.1 reflects operating expenditure and volumes relating to Ancillary Network Services for either "fee-based services" or "quoted services" in accordance with the definitions provided in Appendix F of the Reset RIN. Specifically, fee-based services have been identified as those where a fixed fee is charged to the customer for the provision of the service (i.e. the fee charged to the customer is either fixed per job or fixed per item/activity and not charged on a per hour basis). Quoted services have been identified as those where a quoted fee is provided based on a fixed hourly rate. Quoted services have fees which are charged on an hourly basis as the nature and scope of these services are specific to individual customers' needs and vary from customer to customer.

- Historic and forecast expenditure and volumes for each Ancillary Network Service (which covers all fee-based and quoted services listed in templates 4.3 and 4.4), reconciles to internal planning models used in generating Endeavour Energy's proposed revenue requirements. Specifically, the historic and forecast expenditure and volumes reconcile to the Ancillary Network Service Fee Methodology documents provided as Attachment 8.09 to the Substantive Regulatory Proposal.

- The fee-based services and quoted services listed in tables 4.3.1 and 4.4.1 respectively include all the services identified as Ancillary Network Services in Appendix D of the AER's Framework and Approach Paper (March 2013). This includes all fee-based and quoted services listed in the annual tariff proposal of each relevant year, as well as new fees for services which Endeavour Energy have not previously charged a fee for, but will commence charging a fee from 2015/16 onwards (in accordance with the AER's Framework and Approach Paper).

- A description of each Ancillary Network Service (which covers all fee-based and quoted services listed in templates 4.3 and 4.4), is included in the Service Description page of each Ancillary Network Service Fee Methodology document provided as Attachment 8.09 to the Substantive Regulatory Proposal. The purpose of each service and the activities which comprise each service are outlined in the Service Descriptions.

- Endeavour Energy has not distinguished expenditure for fee-based and quoted services between standard or alternative control services in regulatory templates 4.3 and 4.4. It is noted that for Endeavour Energy, Ancillary Network Services (which covers all fee-based and quoted services) are classified as standard control services for the 2009-14 regulatory period and alternative control services for the 2015-19 regulatory period.

- Endeavour Energy has not distinguished expenditure for fee-based and quoted services as either capital expenditure or operating expenditure in regulatory templates 4.3 and 4.4. However, it is noted that all expenditure related to fee-based and quoted services is operating expenditure.

Source of information

Historic information relating to fee-based and quoted services was extracted from a variety of sources as listed below. This information was used to calculate historic expenditure and volumes for fee-based and quoted services presented in tables 4.3.1 and 4.4.1 respectively.

- Ancillary Network Service Fee Methodology documents – where historic expenditure and volume data has been used to calculate proposed Ancillary Network Service fees for the 2015-19 regulatory period, this data has been presented in tables 4.3.1 and 4.4.1 in order to ensure the data reconciles to internal planning models used in generating Endeavour Energy's proposed revenue requirements.

- Customer Application Management System (CAMS) – A company developed database used for the management of contestable works projects. This system was used to extract historic volume data (where available) for certain services and service sub-categories.

- Banner – Endeavour Energy's corporate customer information and billing system. Banner contains revenue information as well as service order[2] information which has been used to extract historic volume data (where available) for certain services.

- Ellipse – Endeavour Energy's primary IT management system utilised for a variety of functions throughout the company. Ellipse contains Endeavour Energy's general ledger and has been used to extract and/or calculate historic expenditure and volumes related to fee-based and quoted services. Ellipse contains work orders which are a reporting tool used to capture costs / revenue associated with a particular task.

- MBS (Metering Business System) – IT system which supports basic meter data management and market interactions with other market participants and AEMO. MBS includes service order[1] information related to basic meter customers which has been used to extract historic volume data (where available) for certain services.

Methodology and assumptions

The specific methodology and assumptions applied to calculate historic expenditure and volumes varies slightly between each Ancillary Network Service. The individual Ancillary Network Service Fee Methodology documents (Attachment 8.09 to our regulatory proposal) should be referred to in order to understand the methodology applied to calculate historic expenditure and volumes.

Presented below is a high level summary of the methodology and assumptions applied in order to calculate historic expenditure and volumes for each Ancillary Network Service. The methodology applied includes five broad steps:

1. Calculate historic volumes for each Ancillary Network Service at the fee sub-category level;
2. Calculate historic direct expenditure for each Ancillary Network Service at the fee sub-category level;
3. Estimate historic network and corporate overheads for each Ancillary Network Service at the fee sub-category level;
4. Identify the driver for each Ancillary Network Service fee at the fee sub-category level and categorise as either a fee-based service or a quoted service; and
5. Aggregate the historic expenditure and volume data for each Ancillary Network Service and populate tables 4.3.1 and 4.4.1 in accordance with the Reset RIN.

These steps are described in further detail below.

1. **Calculate historic volumes associated with each Ancillary Network Service at the fee sub-category level.**

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[2] A service order is a tool used by Endeavour Energy to initiate work to be carried out for a customer.

As outlined above, the specific methodology applied to calculate historic volumes varies slightly between each Ancillary Network Service. Presented below is a summary which outlines how historic volumes have been calculated for each Ancillary Network Service.

Ancillary Network Service Fee	Volume Calculation Method
Administration Fee	Method 1
Design Information Fee	Method 1
Design Certification Fee	Method 1
Design Recertification Fee	Method 1
Notification of Arrangement	Method 1
Inspection of service work (Level 1 work)	Method 1
Reinspection Fee (Level 1 & 2 work)	Method 1
Inspection of service work (Level 2 work)	Method 1
Access (Standby Person)	Method 1
Access Permits	Method 1
Contestable Substation Commissioning	Method 1
Authorisation of ASP's	Method 1
Site Establishment Fee	Method 1
Conveyancing Information	Method 1
Planning studies relating to distribution connection applications - SIMPLE JOBS	Method 2
Planning studies relating to distribution connection applications - COMPLEX JOBS	Method 2
Connection Offer Service (Basic)	Method 2
Connection Offer Service (Standard)	Method 2
Customer Interface co-ordination for contestable works	Method 2
Inv, rev & impl of remedial actions associated with ASP's connection work	Method 2
Preliminary Enquiry Service - SIMPLE JOBS	Method 2
Preliminary Enquiry Service - COMPLEX JOBS	Method 2
Services involved in obtaining deeds of agreement	Method 2
Clearance to Work	Method 2
Rectification Works	Method 2
Disconnections / Reconnections (Pole Top / Pillar Box)	Method 1
Excluded Distribution Services	Method 2
Meter Test Fee	Method 1
Off Peak Conversions	Method 3
Disconnections / Reconnections (Meter Box)	Method 3
Disconnections / Reconnections (Meter Load Tail)	Method 3
Disconnections / Reconnections (Site Visit))	Method 3
Network Tariff Change Request	Method 3
Special Meter Reads	Method 3
Move in / Move out meter reads	Method 3

Method 1 – These services generally represent Ancillary Network Services for which Endeavour Energy is already charging a fee (i.e. Miscellaneous or Monopoly Fees). As a result, historic volume data is available from Endeavour Energy business systems (i.e. CAMS, Banner or Ellipse), or able to be calculated based on dividing historic revenue by current fees. Initially, historic volume data was extracted from business systems, or derived based on actual historic revenue, for the period 2009/10 to 2012/13 for the purposes of calculating proposed fees for the 2015-19 regulatory period. These volumes have also been used to populate tables 4.3.1 and 4.4.1 for these services. However, due to data limitations, volumes for 2008/09 have been estimated based on the average of actual volumes for the 2009/10 to 2012/13 period. For the Authorisation of ASP's and Conveyancing Information services, volumes for 2008/09 have been estimated based on applying a growth trend observed for the 2009/10 to 2012/13 period.

Method 2 – These services generally represent Ancillary Network Services for which Endeavour Energy has never charged a fee and therefore volume data was unable to be obtained from business systems. In order to calculate proposed fees and revenue requirements for these services for the 2015-19 regulatory period, Endeavour Energy estimated forecast volumes for these services based on information provided by relevant internal stakeholders. In each case, forecast annual volumes were assumed to be constant for the 2015-19 regulatory period in order to calculate the proposed fees and revenue requirements. As a result, in order to estimate volumes for the historic period, Endeavour Energy applied the same volumes assumed for the forecast period.

Method 3 – Each of these services are predominantly carried out by the Market Operations branch in Endeavour Energy, with the services initiated by service orders issued by Retailers or through internal processes. Service order volumes are only available for 2012/13 (first full year MBS was operational) and therefore actual historic volume data can only be provided for 2012/13. In order to estimate volumes for 2008/09 to 2011/12 the following process was undertaken:

- Historic Market Operations branch operating expenditure was split between each relevant Ancillary Network Service based on the proportional split of operating expenditure for the 2012/13 year (which was the basis of developing the proposed Ancillary Network Service fees for 2015-19);
- The unit rate calculated for 2012/13 was de-escalated based on labour/CPI de-escalation factors; and
- Historic operating expenditure calculated for each Ancillary Network Service was divided by the de-escalated 2012/13 unit rate for that year to estimate associated volumes.

2. **Calculate historic direct expenditure for each Ancillary Network Service at the fee sub-category level.**

As outlined above, the specific methodology applied to calculate historic expenditure varies slightly between each Ancillary Network Service. Presented below is a summary which outlines how historic direct operating expenditure has been calculated for each Ancillary Network Service.

Ancillary Network Service Fee	Opex Calculation Method
Administration Fee	Method 1
Design Information Fee	Method 1
Design Certification Fee	Method 1
Design Recertification Fee	Method 1
Notification of Arrangement	Method 1
Inspection of service work (Level 1 work)	Method 1
Reinspection Fee (Level 1 & 2 work)	Method 1

Ancillary Network Service Fee	Opex Calculation Method
Inspection of service work (Level 2 work)	Method 1
Access (Standby Person)	Method 1
Access Permits	Method 1
Contestable Substation Commissioning	Method 1
Authorisation of ASP's	Method 1
Site Establishment Fee	Method 1
Conveyancing Information	Method 2
Planning studies relating to distribution connection applications - SIMPLE JOBS	Method 2
Planning studies relating to distribution connection applications - COMPLEX JOBS	Method 2
Connection Offer Service (Basic)	Method 2
Connection Offer Service (Standard)	Method 2
Customer Interface co-ordination for contestable works	Method 2
Inv, rev & impl of remedial actions associated with ASP's connection work	Method 2
Preliminary Enquiry Service - SIMPLE JOBS	Method 2
Preliminary Enquiry Service - COMPLEX JOBS	Method 2
Services involved in obtaining deeds of agreement	Method 2
Clearance to Work	Method 2
Rectification Works	Method 2
Disconnections / Reconnections (Pole Top / Pillar Box)	Method 2
Excluded Distribution Services	Method 2
Meter Test Fee	Method 2
Off Peak Conversions	Method 3
Disconnections / Reconnections (Meter Box)	Method 3
Disconnections / Reconnections (Meter Load Tail)	Method 3
Disconnections / Reconnections (Site Visit))	Method 3
Network Tariff Change Request	Method 3
Special Meter Reads	Method 3
Move in / Move out meter reads	Method 3

Method 1 – These services represent Ancillary Network Services for which Endeavour Energy is already charging a fee (i.e. Miscellaneous or Monopoly Fees). As a result, historic direct operating expenditure was able to be extracted from historic work orders, or able to be calculated based on resource requirement (labour hours) assumptions and actual labour rates provided by internal stakeholders. This process was initially conducted for the 2010/11 to 2012/13 period for the purposes of calculating proposed fees for the 2015-19 regulatory period. Historic direct operating expenditure was calculated at the total Ancillary Network Service level and then allocated to the fee sub-categories based on the split of volumes and/or standard hours.

In order to estimate direct operating expenditure for the 2008/09 to 2009/10 period, unit rates calculated in 2012/13 dollars for the purposes of calculating proposed fees, were de-escalated based on labour/CPI de-escalation factors and multiplied by the relevant volumes in that year.

Method 2 – These services generally represent Ancillary Network Services for which Endeavour Energy has never charged a fee and therefore direct operating expenditure data was unable to be obtained from business systems. In order to calculate proposed fees and revenue requirements for these services for the 2015-19 regulatory period, unit rates were developed in 2012/13 dollars. These unit rates were de-escalated for the 2008/09 to 2011/12 period based on labour/CPI de-escalation factors and multiplied by the relevant volumes in that year to estimate historic direct operating expenditure.

Method 3 – Each of these services are predominantly carried out by the Market Operations branch in Endeavour Energy, with some involvement from Network Operations (for off peak conversions) and Finance & Compliance & Metering (for network tariff changes).

In order to estimate historic operating expenditure for the Market Operations component, total Market Operations branch operating expenditure for the 2008/09 to 2011/12 period was split between each relevant Ancillary Network Service based on the proportional split of operating expenditure for the 2012/13 year (which was the basis of developing the proposed Ancillary Network Service fees for 2015-19). Market Operations operating expenditure for the 2012/13 year was split between each relevant Ancillary Network Service based on service order volumes and task time-to-complete estimates provided by the Market Operations Manager.

In order to estimate historic operating expenditure for the Network Operations (for off peak conversions) and Finance & Compliance & Metering (for network tariff changes) contribution to these services, 2012/13 unit rates were de-escalated for the 2008/09 to 2011/12 period based on labour/CPI de-escalation factors and multiplied by the relevant volumes in that year.

3. **Estimate historic network and corporate overheads for each Ancillary Network Service at the fee sub-category level.**

The expenditure calculated in step 2 above only relates to direct operating expenditure. In order to allocate a reasonable portion of network and corporate overheads to each Ancillary Network Service for the historic period, the average network and corporate overhead factor derived from the Cost Allocation Methodology (CAM) model for the 2015-19 regulatory period (specific to Ancillary Network Services) was applied to direct costs for 2008/09 to 2012/13 period. This assumes that the ratio of direct costs to costs inclusive of network and corporate overheads for Ancillary Network Services as calculated by the CAM model for the 2015-19 regulatory period, reflects the actual consumption of network and corporate overheads in the historic period. This assumption has been applied as the level of network and corporate overheads as a proportion of company direct costs has not materially changed over time and the Ancillary Network Service activity as a whole has not changed significantly during the current regulatory control period.

4. **Identify the driver for each Ancillary Network Service fee at the fee sub-category level and categorise as either a fee-based service or a quoted service.**

The driver for each Ancillary Network Service fee was identified as either being on a per hour basis or a per unit basis (i.e. per job, project, lot, pole etc.). Based on the identified fee driver, each fee sub-category was identified as either a fee-based service (charged on a per unit basis) or a quoted service (charged on a per hour basis).

5. **Aggregate the historic expenditure and volume data for each Ancillary Network Service and populate tables 4.3.1 and 4.4.1 in accordance with the Reset RIN.**

Historic expenditure and volume data for each Ancillary Network Service was aggregated into a single worksheet and the historic data for each fee sub-category was populated into tables 4.3.1 and 4.4.1 based on the identification performed in step 4 above.

Use of estimated information

As outlined in the methodology above, regardless of the method chosen, historic expenditure and volumes related to fee and quoted services is materially dependent on information recorded in Endeavour Energy's historical accounting records or other records used in the normal course of business (i.e. the approved CAM). However, a number of assumptions (as outlined above) have been applied in order to derive historic expenditure and volume data for some financial years, for certain Ancillary Network Fees and at the fee sub-category level required by tables 4.3 and 4.4. While Endeavour Energy does not believe there are valid alternative assumptions which could lead to a materially different presentation, the number of assumptions applied to present data in the detail required by tables 4.3 and 4.4 has resulted in Endeavour Energy classifying all data in tables 4.3 and 4.4 as Estimated Information.

Material accounting policy changes

Endeavour Energy have not undertaken any material changes in accounting policies which would impact the data contained in tables 4.3.1 and 4.4.1.

Reliability of information

While a number of assumptions have been applied in order to derive historic expenditure and volume data for some financial years, for certain Ancillary Network Fees and at the fee sub-category level required by tables 4.3 and 4.4, Endeavour Energy considers these assumptions to be reasonable and without valid alternatives and therefore the resulting information to be reliable.

Worksheet 5.1 – Material projects

5.1.2 Projects in current regulatory control period

Renewal projects

Compliance with requirements of the notice

Most of the sources of information are official or published documents within the company. Some of the documents have signatures on them by the approval authority. In few cases there is no signature, however, deemed to be approval has been given for the information to be released*.*

Source of information

- Strategic Asset Renewal Plan(SARP)
- Extract of Minutes of the Board
- Notification of Board project approval by email
- SDI 539 Amendment 4 - Substation address, phone and supply details.
- H:\Asset Renewal Planning Branch\Renewal Program\Renewal Projects
- G:\SHARE\Renewal NIO-CWA
- G:\Samp\1314 Financials\SAMP Capex Financials
- Strategic Asset Management Plan (SAMP) 2014-15 v5 0 0
- System Capex Historicals 08 to 12 - 13
- eDocs

Methodology and assumptions

Transferred the information from the original source to this worksheet.

Assumed the proposed start date was the same date as the approval date of the project.

Use of estimated information

- The forward estimate in Strategic Asset Renewal Plan. The information has been transferred to this worksheet. There are estimates derived from historical data, financial report and Ellipse.

- See Worksheet for table 5.1.1 and 5.1.2 for details

Reliability of information

Expenditure on projects is sourced from the Company's financial system and is considered to be reliable. Commissioning dates may be approximate.

Major projects

Compliance with requirements of the notice
Sources of information are official, published and approval documents within the company and documents held in systems within the company.

Source of information
- Strategic Asset Management Plan (SAMP) 2014-15 v5 0 0
- Program Investment Portfolio (PIP)
- Board Papers submitted for approval
- Extract of Minutes of the Board
- Notification of Board project approval by email
- System Capex Historicals 08 to 12 - 13
- eDocs
- H:\spb\filing\zonesub\
- H:\spb\filing\transub\
- NIO reports, Draft NIO reports and Consultation Papers held in the above filing systems.
- Budget worksheets from Commercial and Decision Support
- Actual Project Expenditure Worksheet from Commercial and Decision Support
- Projects Database
- Ellipse
- Transcap

Methodology and assumptions

Transferred the information from the above sources to this worksheet. Some editing and abbreviation has been carried out for the project descriptions.

Assumption

- The proposed start date has been marked as "COMMENCED" if the project has already commenced. Approximate start dates may be inferred from the approval dates of the projects.
- For completed major projects, proposed commissioning dates have been noted as "COMPLETE".
- It is noted that three projects have been listed as complete although there is expenditure forecast in 2014/15. This is due to the substation having been electrically commissioned however minor works are still required to deliver the intended scope of the projects.

Use of estimated information
Generally proposed commissioning dates have been derived from Transcap. This may not line up with expenditure as there may be some expenditure incurred under the relevant project in the year(s) after commissioning. Alternatively, in some cases approximate Commissioning dates have been inferred from the capital expenditure profile.

Reliability of information

Expenditure on projects is sourced from the Company's financial system and is considered to be reliable. Commissioning dates may be approximate.

5.1.4 Non-network asset projects in current regulatory control period

Compliance with requirements of the notice

The information provided on this work sheet is consistent with the requirements of the Notice.

Source of information

- TM1 SCI information
- Ellipse system for 'actual expenditure'
- Extract of Minutes of the Board/Board papers
- Notification of Board project approval by email

Methodology and assumptions

Transferred the information from the original source to this worksheet.

Use of estimated information

- Initial project approval amounts are based on high level project estimates including industry guided values for anticipated land purchase price based on a per square metre valuation.
- Approved expenditure amounts are based on detailed project estimates including independent valuations for actual land purchase.

Reliability of information

5.1.6 Customer connections projects in current regulatory control period

Compliance with requirements of the notice

There have been no customer funded contestable works projects in the current regulatory control period that have required major works funded by Endeavour Energy.

As a result no data has been entered in template 5.1.6.

Worksheet 5.2 – Asset age profile

5.2.1 Asset age profile

Compliance with requirements of the notice
The information provided on this work sheet is consistent with the requirements of the Notice.

Source of information
Age profiles were developed for Endeavour Energy's asset base using:
- Ellipse/Cognos
- GIS/Network Statistics
- ODRC/VDA
- SARP

Methodology and assumptions
Initial profiles were either obtained from existing ODRC/VDA profiles or developed using populated data from Ellipse/Cognos.

Initial profiles were then updated/modified using some of the following methods:
- New quantities added to existing profiles by examining changes in Network Statistic quantities.
- Scaling of profiles to match total quantities reported by Ellipse or GIS. Scaling was either carried out across the whole profile or parts of the profile to reduce the quantity of older assets.
- Some commissioning dates were modified due to either incorrect entries in Ellipse or to reflect updates in the assets.

Use of estimated information
Estimation was required due to lack of commissioning date data. Estimation was carried out with the methods explained above.

Poles
Wood
- Profile developed from profile used in the 2011 VDA analysis which was a modified version of the 2010 ODRC profile. Modification due to SKM removing the tail end portion of poles. First two years of ODRC profile not used due to possibility of incompleteness.
- New quantities added based on Ellipse data.
- To get profile quantity to match Ellipse data, quantity reduction scaling was carried out.
- 50% of the required reduction scaling was applied to wooden poles from 2008 to 1972. 2008 was chosen as the starting point as the new quantities from Ellipse started from 2009. 50% was applied to the tail starting from 1971. 1971 was chosen as it was the start of a 'hump' of older assets.

Concrete & Steel
- Concrete and steel poles profiles were developed using Ellipse data.
- Poles with missing dates were proportionally allocated to the known data.

Overhead Conductors
- Profiles developed off existing ODRC profiles.
- New quantities were derived by looking at new quantities of poles and multiplying by average pole span lengths.

- Scaling (up and down) of the profile was carried out to match the profile to total quantities in Network Statistics.
- Where scaling up was required, scaling was applied to the whole profile.
- Reduction scaling was required for LV conductors. Scaling was applied from 1969/70 to focus reduction from a 'hump' of older assets.
- Reduction scaling was required for 11/22kV conductors. Scaling was applied to the last 10 years of the profile to focus reduction in the older assets assuming that renewals are focused on the older assets.

Underground Cables
- Profiles developed off existing ODRC profiles.
- Existing profile scaled to match Network Statistics quantity of 2007/08. First two years of ODRC profile not used due to possibility of incompleteness.
- New quantities were derived by examining the changes in asset volumes reported by annual historical Network Statistic reports.

Service Lines
- Profiles developed off existing ODRC profiles.
- New quantities were derived by examining the changes in asset volumes reported by historical Network Statistic reports.
- Existing portion of UG profile was scaled to match total quantities.
- A quantity of OH services were reduced from 1969/70, because of 45 years old to reflect service mains replacement program introduced in the current reg period. Remaining part of profile scaled to match total quantities.

Transformers
Distribution
- Profile developed from Ellipse data.
- Transformers with a missing date were assigned a date using regression based on equipment number and dates of known transformers.

Transmission
- Profile developed from Ellipse data.

Switchgear
Circuit Breakers
- Profile developed from Ellipse data.
- Few updates made by Jonathan Cook.

Distribution Mains Switchgear
- Profile developed from Ellipse data.
- Air break switches, load break switched, sectionalisers and reclosers with unknown dates were proportionally allocated.
- Drop out fuses and underslung links with unknown dates were evenly proportioned to the oldest known switch. These were allocated differently due to the high volume of unknown dates resulting in a very young profile not indicative of actual assets.

Transmission Mains Switchgear
- Profile developed from Ellipse data.
- Assets with unknown dates were proportionally allocated.

LV Links

- Profile developed off existing ODRC profile.
- New quantities were derived by examining the changes in asset volumes reported by historical Network Statistic reports.
- Tail end of profile from 1971 was scaled to match total quantities to focus reduction in the 'hump' of older assets.

Street lighting
- Profile developed from Ellipse data.
- Unknowns used to fill gap in 2002/03 and 2003/04.
- Top of spike in 1997/98 allocated to gap in 2000/01.
- 2 spikes from the oldest part of the profile were proportionally allocated to oldest part of profile from 1980/81.

Towers
- Profile obtained from existing ODRC profile.
- Small quantities of reasonable commissioning dates from Ellipse were used to update the profile.
- A small quantity was removed from the oldest group of towers to match total Network Statistics quantities.

Substation Establishments
- Profile developed from Ellipse data.
- Some substation dates were modified to reflect major renewals in the substations.
- Data in calendar year, which is not a major issue as the commissioning process for a substation can take several months.

Pilot Cables
- Profile developed from detailed review of ages of connected substations, modified by known recent replacement activity.
- Updates made by staff

Distribution Substations
- Profile developed from Ellipse data.
- Some missing dates obtained from transformer fitments or substation of closest asset number.

Cap Banks
- Profile developed from Ellipse data.
- Cap banks with a missing date were assigned a date using regression based on Ellipse equipment number and dates of known transformers.

SCADA
- Profiles obtained from the 2014/15 SARP document.
- Profile data for SARP came from SCADA group.
- Data in calendar year.

Reliability of information

Age profiles were developed based on available data and existing profiles. Estimation was carried out to allocate quantities of assets with unknown commissioning dates to the profiles. For older assets the age information is not likely to be as reliable as the information for newer assets where more reliable processes for capturing and storing asset information exist.

Worksheet 5.3 – Maximum demand at network level

5.3.1 Raw and weather corrected coincident maximum demand at network level

Compliance with requirements of the notice

All data supplied complies with the requirements of the Regulatory Information Notice. Data has been entered into the spreadsheet by following the instructions set out in the RIN.

Source of information

Network Load History (NLH) database – Raw & Co-incident Actuals

Summer Demand Forecast 2014-2023 – Weather corrected values for all financial years except FY2011/12. Data obtained from this report was also used to populate forecast fields.

Winter Demand Forecast 2013-2022 – Weather corrected values for FY2011/12

Methodology and assumptions

Actual Data (Raw & Co-incident) requested for each financial year was taken from NLH.

All weather corrected and forecasting Information was taken from the approved Summer (SDF2014-2023) and Winter forecast reports (WDF2013-2022).

Network total refers to the summation of all the Bulk Supply Points (BSP) and all the known embedded generation.

Embedded Generation has been included in the figures provided.

FY2011/12 is the only financial year in the requested series where peak demand occurred in winter. All other financial years the peak demand occurred in Summer.

See Basis of Preparation (Worksheet 5.4) for short description of forecasting methodology and weather correction.

Use of estimated information

No Estimations were provided in this worksheet.

Reliability of information

Network load information is sourced from measured values and is considered reliable.

Worksheet 5.4 – Maximum demand and utilisation at spatial level

5.4.1 Non-coincident and coincident maximum demand

Compliance with requirements of the notice

All data supplied complies with the requirements of the Regulatory Information Notice. Data has been entered into the spreadsheet by following the instructions set out in the RIN.

Source of information

Network Load History (NLH) database – Raw & Co-incident Actuals

Summer Demand Forecast 2014-2023 – Weather corrected values for all financial years except FY2011/12. Data obtained from this report was also used to populate forecast fields.

Winter Demand Forecast 2013-2022 – Weather corrected values for FY2011/12

Transmission Network Planning Review (TNPR) 2009 to 2013 Reports – Firm Capacity Ratings

Endeavour Energy Transmission Network Cyclic Rating Report February 2014 – Cyclic Ratings

FY2013/14 data has not been finalised and therefore it has not been filled in for Actual data.

Methodology and assumptions

FY2011/12 is the only financial year in the requested series where peak demand occurred in winter. All other financial years the peak demand occurred in summer. In this worksheet all substations listed for 2011/12 are based on winter demand values because of the network peaking in winter in the 2011/12 financial year.

Subtransmission substations refer to the Bulk Supply Points (BSP).

Actual Data (Raw & Co-incident) requested for each financial year was taken from NLH.

All weather corrected and forecasting Information was taken from the approved summer (SDF2014-2023) and winter forecast reports (WDF2013-2022).

Embedded Generation

Embedded Generation has been included in the figures provided.

Subtransmission Substation:

Dapto BSP: Generation is included into Dapto BSP figures. Scheduled Generation is from the Tallawarra Generator which can supply up to 435MW.

Sydney West BSP: Generation is included into Sydney West BSP figures. Both Semi Scheduled Generation (Smithfield) and Non-Scheduled (Appin & Tower Colliery) Generation is included. Smithfield can supply up to 160MW. Appin & Tower can supply up to 97MW.

Substation Cyclic Ratings (MVA):

Substation Ratings – All substation ratings refer to the substations firm capacity (N-1) and have been taken from the TNPR reports. The only known cyclic ratings for zone substations can be found below:

Albion Park as at February 2014 - 13.04(trf1) & 11.93 (trf2) & 11.93 (trf3)

Arndell Park as at February 2014 - 42.31(trf1) & 42.31 (trf2)

Culburra as at February 2014 - 10.53(trf1) & 10.53(trf2)

Kangaroo Valley as at February 2014 - 5.72(trf1) & 2.73(trf2)

Nepean Zone as at February 2014 - 38.11(trf6) & 38.11(trf7)

Robertson as at February 2014 - 3.81(trf1) & 3.81(trf2)

Schofields as at February 2014 - 47.63(trf1) & 47.63(trf2)

South Granville as at February 2014 - 26.57(trf1) & 26.57(trf2)

Substations where Maximum Demand in MVA was higher than MVA values coinciding with Maximum MW:

Subtransmission Substation:

Wallerawang BSP

FY2009/10 – Maximum MVA is 112.7MVA, FY2010/11 – Maximum MVA is 109.0MVA

Zone Substation:

Baulkham Hills 11kV FY2008/09 - Maximum MVA is 36.0385

Cabramatta FY2008/09 - Maximum MVA is 30.1526

Cambridge Park FY2008/09 - Maximum MVA is 29.116

Cattai FY2009/10 - Maximum MVA is 12.1360

Culburra FY2009/10 - Maximum MVA is 9.94

Darkes Forest FY2010/11 - Maximum MVA is 1.22442, FY2011/12 - Maximum MVA is 1.185

Eastern Creek FY2009/10 - Maximum MVA is 12.3693

Helensburgh FY2008/09 - Maximum MVA is 12.92

Inner Harbour FY2009/10 - Maximum MVA is 9.11, FY2010/11 Maximum MVA is 9.469

Katoomba FY2010/11 - Maximum MVA is 13.32

Lennox FY2012/13 - Maximum MVA is 31.8

Moorebank FY2012/13 - Maximum MVA is 39.07

Mungerie Park FY2011/12 - Maximum MVA is 23.917

Nowra FY2011/12 - Maximum MVA is 20.888

Schofields FY2012/13 - Maximum MVA is 17.589

South Wollongong FY2009/10 - Maximum MVA is 14.88

Wisemans FY2008/09 - Maximum MVA is 5.54

Yennora FY2010/11 - Maximum MVA is 25.62

Substations that have been de-commissioned, commissioned or expected to be commissioned

Sub Transmission:

Commissioned:

Holroyd BSP – Expected to be commissioned FY2013/14

Decommissioned:

None

Zone Substation:

Commissioned:

Abbotsbury – Expected to be commissioned in FY2014/15

Berrima Junction – Commissioned in FY2009/10

Casula - Commissioned in FY2013/14

Cawdor – Commissioned in FY2012/13

Chertion Avenue - Commissioned in FY2012/13

Chipping Norton - Commissioned in FY2013/14

Claremont Meadows - Commissioned in FY2013/14

Denham Court - Expected to be commissioned in FY2015/16

East Richmond - Commissioned in FY2013/14

Edmondson Park - Expected to be commissioned in FY2015/17

Figtree - Commissioned in FY2013/14

Glenorie- Expected to be commissioned in FY2013/14

Huntingwood - Commissioned in 2013/14

Jordan Springs – Currently running on a mobile substation, expected commissioning in FY2014/15

Nepean Zone - Commissioned in FY2012/13

North Eastern Creek- Commissioned in FY2012/13

North Warragamba – Commissioned FY2009/10

Oran Park - Currently running on a mobile substation, expected commissioning in FY2014/15

The Oaks - Commissioned in FY2013/14

Tomerong Zone - Expected to be commissioned in FY2014/15

West Liverpool Zone - Commissioned in FY2012/13

West Parramatta - Commissioned in FY2013/14

Wilton - Commissioned in FY2013/14

Decommissioned:

Camden – Decommissioning started in FY2012/13

Hoxton Park – Decommissioned FY2012/13

Parramatta – Expected to be decommissioned FY2013/14

Richmond – Expected to be decommissioned FY2013/14

Warragamaba - Decommissioned FY2008/09

A note about special Zone Substations:

Endeavour Energy has two main growth sectors in its region – the North West and South West Sectors. Three fictional zone substations have been established to provide a way to show the unallocated load expected from the large planned developments. It is envisaged that load will remain on these substations until it is allocated to an existing substation or a new substation in the future.

North West Sector

North West Sector represents growth around the Marsden Park Industrial Site & Sydney Business Park. The load is expected to be allocated to zone substations supplied by Vineyard BSP.

South West Sector (Macarthur)

South West Sector Macarthur represents Residential and Employment land in Bringelly, Catherine Field, North Catherine Field and Maryland. The load is expected to be allocated to zone substations supplied by Macarthur BSP.

South West Sector (Sydney West)

South West Sector Sydney West represents Residential and Employment land in Rossmore, North Rossmore, Austral, South Leppington, North Leppington, Kemps Creek, Oakdale West and North Bringelly. The load is expected to be allocated to zone substations supplied by Sydney West BSP.

Short Description of the Weather Correction Process and forecasting methodology:

Historical peak demands for each season are corrected to the respective reference temperatures. The temperature correction is based on a second-order polynomial fit to the weekday daily demands and the corresponding maximum temperatures at Nowra for the South Coast or at Richmond for the remaining areas in summer, and daily 6 pm temperatures at Richmond for all Endeavour Energy areas in winter.

Peak demand forecast accounts for the total growth from the existing customers as well as the new customers. The forecasting process can be divided into two major steps. The first step is to estimate the organic growth at the zone substation which specifies the internal growth from its existing customers likely to be experienced over the forecast period. For summer, it was calculated by the known current and projected penetration rates of air conditioners and the percentage of residential peak load at the zone substation. This organic growth at the zone substation is used to establish the base level of the 10-year forecast. For winter, the organic growth at zone substations is assumed to be flat with zero growth.

The second step of the forecast process involves incorporating the planner's inputs to the base level forecast. The inputs include new developments planned to occur (lot releases), new load increases expected from customer applications (spot loads) and also information regarding the transfer of load from one zone substation to another (load transfers). The final forecast at a zone substation is derived from the base level forecast after adjustment for planned load transfers, spot loads, land releases and re-development in the zone substation.

The final forecasts for all zone substations would be presented to the Network Planners for confirmation of the expected demand growth. The Network Planners' local knowledge is vital in determining load transfer, embedded generation, proposed spot-loads and predicted lot release information. This feedback also provides an audit trail for quality purposes.

Forecasts at transmission substations and bulk supply points are calculated by the corresponding historical diversity factors. The zone substation forecasts are summated to obtain the undiversified totals and then multiplied by the calculated diversity factor for that transmission substations or bulk supply point.

Use of estimated information

Estimations & Assumptions

For each substation where no actual MVA information was available for the financial years required, an MVA estimate was calculated by dividing the substations historical average power factor by the actual recorded peak MW value.

If the explanation above is not valid for a particular substation it will be identified below with reasons for the estimation and the approach used to obtain the estimation.

Sub Transmission:

Dapto BSP -

FY2008/09 An assumed PF of 0.9863 was used for the conversion to MVA

FY2010/11 An assumed PF of 0.9979 was used for the conversion to MVA

FY2011/12 An assumed PF of 0.99639 was used for the conversion to MVA

Liverpool BSP –

FY2011/12 An assumed PF of 0.9967 was used for the conversion to MVA

Macarthur BSP –

FY2009/10 – These values reflect Ambarvale zone substation as there was not sufficient metering at the BSP at the time. Ambarvale zone was the only zone that was fed from Macarthur BSP at the time Macarthur BSP was commissioned.

For FY2010/11 to FY2012/13 an assumed PF of 0.95 was used for the conversion to MVA

Regentville BSP –

For FY2008/09 to 2012/13 an assumed PF of 0.967 was used for the conversion to MVA

Sydney North BSP –

For FY 2008/09 to FY2012/13 an assumed PF of 0.995 was used for the conversion to MVA

Vineyard BSP –

For FY2010/11 to FY 2012/13 an assumed PF of 0.9704 was used for the conversion to MVA

Zone Substation:

Anzac Village –

FY2012/13- No Data at time of Endeavour Energy Peak

Campbelltown –

FY2009/10 - No Data at time of Endeavour Energy Peak

Darkes Forest –

FY2008/09 – Estimated data was used for MW and MVA which is based on the previous historical peak as there is no data for the substation in this financial year. There is also no data at time of Endeavour Energy Peak.

Gerringong –

Actual MVA values were erroneous for the following financial years.

For FY2010/11 an assumed PF of 0.964 was used for the conversion to MVA

For FY2011/12 & FY2012/13 an assumed PF of 0.973 was used for the conversion to MVA

Huskisson –

FY2008/09 - No Data at time of Endeavour Energy Peak

Kandos –

FY2008/09 - No Data at time of Endeavour Energy Peak

Meadow Flat –

FY2008/09 - No Data at time of Endeavour Energy Peak

North Parramatta –

FY2012/13- No Data at time of Endeavour Energy Peak

Quakers Hill –

FY2008/09 – Estimated data was used for MW and MVA which is based on the previous historical peak as there is erroneous data for the substation in this financial year. There is also no data at time of Endeavour Energy Peak.

Robertson –

FY2008/09 – Estimated data was used for MW and MVA which is based on the previous historical peak as there is erroneous data for the substation in this financial year. There is also no data at time of Endeavour Energy Peak.

South Nowra –

FY2011/12- No Data at time of Endeavour Energy Peak

West Castle Hill –

FY2011/12- No Data at time of Endeavour Energy Peak

West Wetherill Park 11kV –

FY2008/09 – Estimated data was used for MW and MVA which is based on the previous historical peak as there is erroneous data for the substation in this financial year. There is also no data at time of Endeavour Energy Peak.

FY2011/12- No Data at time of Endeavour Energy Peak

Wetherill Park –

FY2011/12- No Data at time of Endeavour Energy Peak

Whalan –

FY2011/12- No Data at time of Endeavour Energy Peak

Windsor –

FY2011/12- No Data at time of Endeavour Energy Peak

Wombarra –

FY2011/12- No Data at time of Endeavour Energy Peak

Reliability of information

Network load information is sourced from measured values and is considered reliable.

Worksheet 6.1 – Telephone answering

6.1.1 Telephone answering data

Compliance with requirements of the notice

The information provided on this work sheet is consistent with the requirements of the Notice. The data was sourced from reports and systems which have been used to supply similar data for previous RIN's.

Source of information

Endeavour Energy obtained the information provided in this work sheet from the monthly Network call stats reports. The data was originally sourced from the 'Contact Centre 6 (CC6)' application, and the 'Intellemanager Web View Reporting' application. Endeavour Energy have two call centres at Huntingwood and Coniston, this data has been combined in response to this template.

Methodology and assumptions

Endeavour Energy applied the following methodology to provide the required information:
- Actual monthly call data was used as the basis for the preparation of this data
- Each months data was divided by the number of days in that month, to provide average daily data per month

Use of estimated information

Endeavour Energy has used estimated information for daily telephone answering data. The reasons for this are as follows:

- Endeavour Energy has not retained daily call data which contains all of the fields that were required to complete this template;

- As Endeavour Energy's core call centre reporting is based on monthly data, it was assumed that the daily average of each month would provide a reasonable substitute to actual daily data, as the sum of all averaged days would equal the sum of all actual days if these could have been provided.

Reliability of information

Worksheet 6.2 – Reliability performance

6.2.1 Unplanned minutes off supply (SAIDI) – Actual, target and proposed reliability

6.2.2 Unplanned interruptions to supply (SAIFI) – Actual, target and proposed reliability

Compliance with requirements of the notice

Reported SAIDI/SAIFI complies with the requirements of the STPIS and AER determination reset RIN.

Source of information

Base outage data (customers interrupted and CMI) - Unplanned

2008/09 to 2011/12 – Data sourced from System Fault Recording database (SFR). All records entered into this database were in accordance with a Work Place Instruction WPB1007. This database has been replaced by the Outage Management System (OMS).

Reporting tool – Cognos 7 impromptu

20012/13 – Data sourced from OMS. All records in this database were validated and checked in accordance with a Work Place Instruction WPB1014.

The data for this RIN was obtained from working files used to produce the ENPR's in accordance with WPB1011.

Reporting tool – Cognos 8

Actual – 2008/09 to 2012/13

1. Appendix E 22 of the RIN

22.2 A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premises. The customer interruption starts when recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. Does not include subsequent interruptions caused by network switching during fault finding. An interruption ends when supply is again generally available to the customer

Note:

  a. **Sustained interruption as being greater than 0.5 seconds**. SAIDI definition in appendix A of the STPIS <u>also</u> states that unplanned SAIDI excludes momentary interruptions (**one minute or less).**

The MAIFI definition is " The total number of customer interruptions of **one minute or less**"

Therefore Endeavour Energy's interpretation is:

0.5 seconds to 1 minute = Momentary interruption (MAIFI)

1 minute or greater = sustained interruption (SAIDI/SAIFI)

b. **Outages affecting single premises –** reliability information for the years 2008/09 to 2011/12 inclusive does not include outages affecting single premises as they were not recorded in the data base (SFR) used at the time. Single premise outages that occur as a result of a fault on Endeavour Energy's network are included in the 2012/13 reliability result, as these outages are now recorded in the current Outage Management System.

c. **Subsequent interruptions caused by network switching during fault finding,** in general switching operations associated with an unplanned incident may include subsequent interruptions to customers that are associated with fault finding. Current systems do not have any facility to identify these operations and therefore exclude them from reliability calculations. *It should be noted that removing these operations from reliability calculations would result in an inaccurate record of actual customer experience*

Estimated – 2013/14

2013-14 estimated results are the average of the previous three years.

Proposed Targets

Proposed Urban and Short Rural targets are the average of the most recent five years (2009/10 to 2013/14) performance and are set in line with Endeavour Energy's corporate reliability objective which is to maintain reliability at current levels. This is highlighted in Endeavour's Reliability Plan.

Long Rural targets

Endeavour Energy only has one Long Rural feeder that supplies 292 customers. The performance of this feeder, as shown in Figure 1, reflects the volatility in reporting against a single feeder in a category type. Previous Electricity Network Performance Reports (2006/07, 2007/08 and 2008/09) identified this issue, noting that "The Minister has recognised this in not imposing a Long Rural target for Integral (Endeavour) Energy." Therefore, as Endeavour Energy has no Long Rural feeder category performance targets under the NSW Operating Licence, no Long Rural feeder category performance targets are proposed under the STPIS Proposal (2014-2019 Regulatory Control Period) and consequently no targets are forecast.
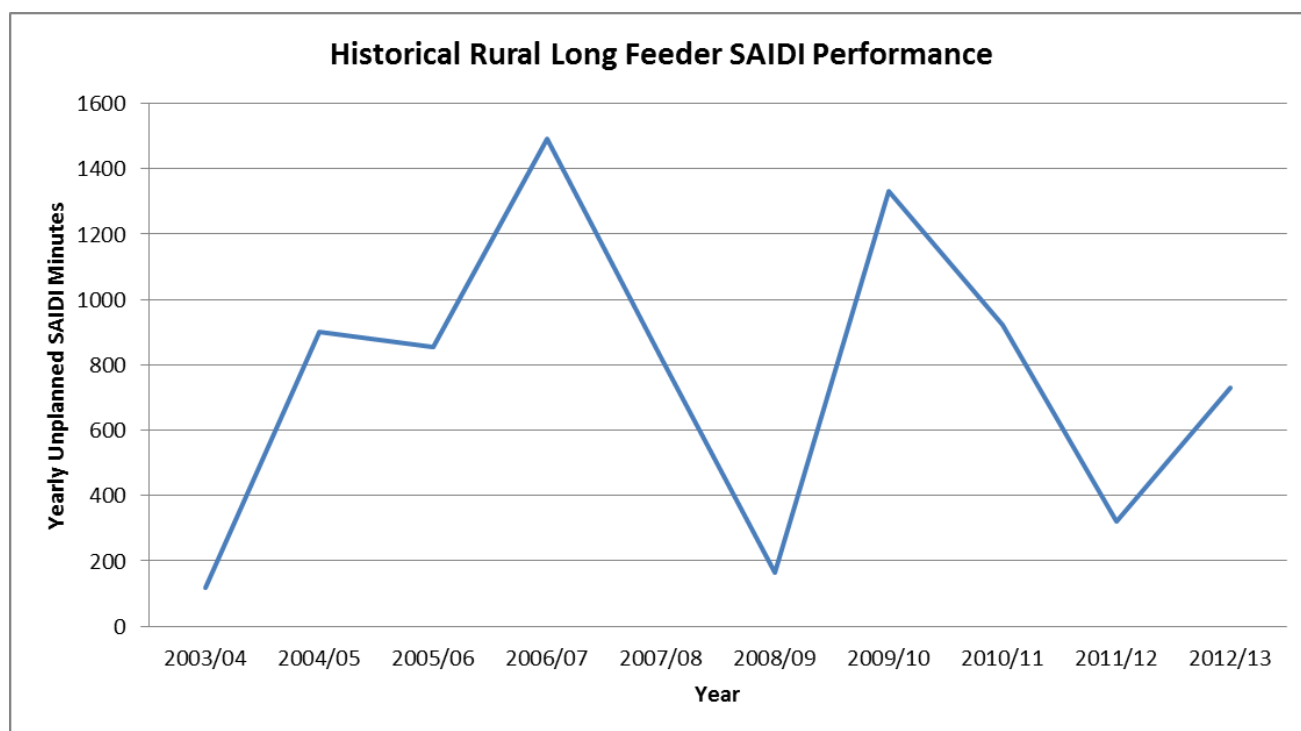
Figure 1 – Historical SAIDI performance of Endeavour Energy's only Rural Long feeder.

Methodology and assumptions

CBD feeder category

We note that definition of a CBD feeder in the RIN/STPIS differs to the definition in Endeavour Energy's NSW Operating Licence.

As Endeavour Energy has no CBD classified feeders under the NSW Operating Licence, no feeders are classified as CBD under the STPIS.

Use of estimated information

See above.

Reliability of information

6.2.3 Unplanned momentary interruptions to supply (MAIFI) – Actual, target and proposed reliability

Compliance with requirements of the notice

MAIFI reporting capability was introduced in the OMS database from 2012/13. However the OMS only records momentary outages that are on SCADA connected reclosers and therefore reported MAIFI information does not include interruptions that occur on non-SCADA connected devices.

OMS records MAIFIe, which differs from the requirements of the RIN in that multiple reclose operations on a single event are only counted as a single MAIFI occurrence.

Source of information

2008/09 to 2011/12 – Actual data not available, therefore estimate provided.

2012/13 - Actual MAIFIe data is sourced from OMS. All records in this database were validated and checked in accordance with a Work Place Instruction WPB1014.

Reporting using Cognos 8

Methodology and assumptions

2012/13 feeder category MAIFIe calculated using customer numbers reported in table 6.2.4

Use of estimated information

2008/09 to 2011/12 - Estimated, on an assumption that there is a correlation between SAIFI and MAIFI.

Therefore the ratios of 2012/13 SAIFI/MAIFI were applied to the previous SAIFI figures to estimate MAIFI.

Estimated 2013/14 – Estimation method the same as the SAIDI and SAIFI estimations in 6.2.1 and 6.2.3

Proposed Targets - 2014/15 to 2018/19 targets, the same as the SAIDI and SAIFI estimations in 6.2.1 and 6.2.3

As noted above, no MAIFI targets have been proposed for the single Long Rural feeder

Reliability of information

6.2.4 Customer numbers

Compliance with requirements of the notice

Customer numbers comply with the requirements of the notice in that they are the average customers over the reporting period.

It should be noted that a recent SAIDI improvement project to improve the accuracy of customers the OMS has implemented the customer definition in the STPIS including unmetered customers and The OMS database implements this definition from 2013/14 onwards. Previous years excluded unmetered customers .

It should also be noted that the application of average customers over the reporting period as per the requirements of the notice (and the future application the STPIS customer definition) is only for the purposes of determining reliability. Therefore customer numbers may not reconcile to customer numbers reported in other sections.

Source of information

Previously published Electricity Network Performance Reports (ENPR).

Methodology and assumptions

The information was taken from previously published Electricity Network Performance Reports (ENPR).

Use of estimated information

Estimated customer numbers based on previous years

Reliability of information

6.2.5 Customer service

Compliance with requirements of the notice

The information provided on this work sheet is consistent with the requirements of this Notice. The data was sourced from reports and systems which have been used to supply similar data for previous RIN's.

The RIN requires incidents to be excluded under clause 3.3 of the STPIS. Hence, data complies with the calculation methodology of the STPIS and the removes exclusions permitted under clause 3.3a. Refer to template 6.4 for major event days.

Source of information

Endeavour Energy obtained the information provided in this work sheet from the monthly Network call stats reports. The data was originally sourced from the 'Contact Centre 6 (CC6)' application, and the 'Intellemanager Web View Reporting' application.

Methodology and assumptions

Annual data up to FY 12/13 is actual data. The data for the FY 13/14 is based on actual data from July 2013 to March 2014, and estimated data from April 2014 to June 2014.

- The estimated call data for FY 13/14 assumes that the last three months of that reporting year will have average call volume of the previous 12 months;
- The estimated '% calls answered in 30 sec' data for FY 13/14 assumes that the last three months of that reporting year will have average '% calls answered in 30 sec' equal to that of the months from July 2013 to March 2013.

Use of estimated information

- Endeavour Energy has only used estimated information for future dated periods.
- Estimated call data for periods 2014-15 to 2018-19 has been based on the average of actual data from February 2013 to March 2014.
- Estimated '% calls answered in 30 sec' data for periods 2014-15 to 2018-19 has been based on the average of actual data from February 2013 to Mar 2014.

Reliability of information

It should be noted that the "Number of calls received" includes calls abandoned within 30 seconds. It will therefore differ from the number in template 6.1, "subtotal number of calls received."

6.2.6 Estimated data percentage accuracy SAIDI

Compliance with requirements of the notice

No definition or direction for determining accuracy was provided in the RIN therefore an estimation methodology used in an external audit of the 2009/10 RIN (submitted to the AER) was used.

Source of information

As above.

Methodology and assumptions

The audit identified the potential for errors in transcription, system customer numbers, business rules applied to non 3 phase outages and de-energisation/restoration time stamps (duration).

The error % was quantified as

Transcription - 0.1%
Customer Numbers - 3.9% in 2009/10 and 2.9% in 2008/09 (due to different customer numbers obtained from different systems.)
Business Rules - 0.4%
Duration – 1%

The SAIDI improvement project was initiated to remove the customer numbers error and was implemented in 2013/14. Therefore the customer number error that impacted SAIDI and SAIFI is now considered to be zero from 2013/14 onwards (with an assumed improvement over the period between)

All other errors are considered to be relatively consistent.

The calculated errors are:

SAIDI Error	2008-09	2009-10	2010-11	2011-12	2012-13	2013/14 on
Transcription – Control Room	0.1	0.1	0.1	0.1	0.1	0.1
Transcription – Network Perf Review	0.1	0.1	0.1	0.1	0.1	0.1
Customer numbers	2.9	3.9	3.6	3.2	2.9	0
Business Rules	0.4	0.4	0.4	0.4	0.4	0.4
Duration	1.0	1.0	1.0	1.0	1.0	1.0
TOTAL	**4.5**	**5.5**	**5.2**	**4.8**	**4.5**	**1.6**

Use of estimated information

See above.

Reliability of information

6.2.7 Estimated data percentage accuracy SAIFI

Compliance with requirements of the notice

No definition or direction for determining accuracy was provided in the RIN therefore an estimation methodology used in an external audit of the 2009/10 RIN (submitted to the AER) was used.

Methodology and assumptions

The audit identified potential for errors in transcription, system customer numbers, business rules applied to non 3 phase outages and de-energisation/restoration time stamps (duration).

The error % was quantified as

Transcription – N/A

Customer Numbers - 3.9% in 2009/10 and 2.9% in 2008/09 (due to different customer numbers obtained from different systems.)
Business Rules - 0.4%
Duration – N/A

The SAIDI improvement project was initiated to remove the customer numbers error and was implemented in 2013/14. Therefore the customer number error that impacted SAIDI and SAIFI is now considered to be zero from 2013/14 onwards (with an assumed improvement over the period between)

All other errors are considered to be relatively consistent.

The calculated errors are:

SAIFI Error	2008-09	2009-10	2010-11	2011-12	2012-13	2013/14 on
Transcription – Control Room	N/A	N/A	N/A	N/A	N/A	N/A
Transcription – Network Perf Review	N/A	N/A	N/A	N/A	N/A	N/A
Customer numbers	2.9	3.9	3.6 - approx.	3.2 - Approx.	2.9	0
Business Rules	0.4	0.4	0.4	0.4	0.4	0.4
Duration	N/A	N/A	N/A	N/A	N/A	N/A
TOTAL	**3.3**	**4.3**	**4.0**	**3.6**	**3.5**	**0.4**

Use of estimated information

See above.

Reliability of information

Worksheet 6.3 – Sustained interruptions to supply

6.3.1 Sustained interruptions to supply (from 1 July 2008)

Compliance with requirements of the notice
Sustained interruptions prepared as per the STPIS.

Appendix E 22 of the RIN

22.2 A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premises. The customer interruption starts when recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. Does not include subsequent interruptions caused by network switching during fault finding. An interruption ends when supply is again generally available to the customer

Note:

a. **Sustained interruption as being greater than 0.5 seconds**. SAIDI definition in appendix A of the STPIS <u>also</u> states that unplanned SAIDI excludes momentary interruptions (**one minute or less).**

    The MAIFI definition is " The total number of customer interruptions of **one minute or less**"

    Therefore Endeavour Energy's interpretation is:

    0.5 seconds to 1 minute = Momentary interruption (MAIFI)

    1 minute or greater = sustained interruption (SAIDI/SAIFI)

b. **Outages affecting single premises –** reliability information for the years 2008/09 to 2011/12 inclusive does not include outages affecting single premises as they were not recorded in the data base (SFR) used at the time. Single premise outages that occur as a result of a fault on Endeavour Energy's network are included in the 2012/13 reliability result, as these outages are now recorded in the current Outage Management System.

c. **Subsequent interruptions caused by network switching during fault finding,** in general switching operations associated with an unplanned incident may include subsequent interruptions to customers that are associated with fault finding. Current systems do not have any facility to identify these operations and therefore exclude them from reliability calculations. ***It should be noted that removing these operations from reliability calculations would result in an inaccurate record of actual customer experience***

Source of information
2008/09 to 2011/12 – Data sourced from System Fault Recording database (SFR). All records entered into this database were in accordance with a Work Place Instruction WPB1007. This database has been replaced by the Outage Management System (OMS).

The data for this RIN was obtained from working files used to produce the ENPR's in accordance with WPB1011.

Reporting tool – Cognos 7 impromptu

20012/13 – Data sourced from OMS. All records in this database were validated and checked in accordance with a Work Place Instruction WPB1014.

The data for this RIN was obtained from working files used to produce the ENPR's in accordance with WPB1011.

To ensure completeness of data, the sustained interruptions data collated for table 6.3.1 was summarised to populate the data for table 6.2.1 and 6.2.2. Unplanned SAIDI was then compared to previously published ENPR figures.

		2008/09	2009/10	2010/11	2011/12	2012/13
A	CMI (customers interrupted x average duration) - ENPR source data in 6.3.1	95269655	69241992	122498015	147792776	103500386
B	Customers – Tbl 6.2.4	856658	863221	872651	879107	892037
C	Calculated SAIDI (A/B)	111.2	80.2	140.4	168.1	116.0
D	ENPR SAIDI	111.2	80	140	168	116
E	Table 6.2.1 SAIDI - Unplanned	111.2	80.2	140.4	168.1	116

Reporting tool – Cognos 8

Planned outage data

Data originally sourced from System Control Branch databases each year and prepared for ENPR. The data for this RIN was obtained from working files used to produce the ENPR reports in accordance with WPB1011

Methodology and assumptions

Reason for Interruption – The required reasons for interruptions provided by the AER do not directly align to the 'Causes' recorded in the SFR or OMS databases, therefore a separate exercise was carried out to allocate an AER cause to the individual interruptions.

STPIS excluded interruptions (STPIS 3.3a) are assigned to relevant interruptions by 'Cause'

Major Event Days (MED's) have been determined in accordance with the requirements of the STPIS and daily SAIDI figures detailed in Table 6.4.

Note: The 2014 Economic Benchmarking RIN required the application of the 2012/13 MED SAIDI threshold to all previous years (2005/06 to 2012/13). As a consequence, the number of MEDs and adjusted statistics may differ between the Benchmarking RIN and this RIN.

Use of estimated information

Endeavour Energy has not used estimated information for this section.

Reliability of information

Worksheet 6.4 – Historical major event days

6.4.1 Major event day data

Compliance with requirements of the notice

The RIN requires incidents to be excluded under clause 3.3 of the STPIS.

It is Endeavour Energy's position that only incidents under clause 3.3a of the STPIS should be excluded, on the basis that excluded events (3.3b) cannot be determined prior to the MED calculation as it is the MED calculation that determines the exclusion threshold.

Hence, data complies with the calculation methodology of the STPIS and the removes exclusions permitted under clause 3.3a.

Source of information

Working files used to calculate Beta thresholds at the time were used as the data source for the RIN.

Beta thresholds are calculated in accordance with WPB1012 and the original data source was:

2008/09 to 2011/12 – Data sourced from System Fault Recording database (SFR). All records entered into this database were in accordance with a Work Place Instruction WPB1007. This database has been replaced by the Outage Management System (OMS).

Reporting tool – Cognos 7 impromptu

20012/13 – Data sourced from OMS. All records in this database were validated and checked in accordance with a Work Place Instruction WPB1014.

Methodology and assumptions

Actual information reported.

Use of estimated information

Endeavour Energy has not used estimated information for this section.

Reliability of information

Worksheet 7.4 – Shared assets

7.4.1 Total unregulated revenue earned with shared assets

Compliance with requirements of the notice

Requirement

It is understood that compliance with this requirement involves the following:

- Population of Regulatory Template 7.4

Demonstrated Compliance

- Compliance has been demonstrated by populating the template

Source of information

Information was obtained from the following sources:

- Data extracts of Non Standard Control revenue transactions from Endeavour Energy's ERP system – Management Accountant Labour Analytics

- Endeavour Energy's 2012-13 RIN workings containing mapping of ERP System Accounts Codes to Revenue Classifications – Financial Policy & Reporting Manager and Manager, Commercial & Decision Support

- Commercial Managers and Business Analyst investigations to identify the assets used to derive Unregulated Revenue stream

- NBN Information provided by the Facilities Access And Commercial Analyst based on best endeavours to estimate the volume of affected assets and arrangements relating to revenue rates.

- SCI forecast data for Other Revenue was supplied by the Budgeting And Forecasting Manager

Methodology and assumptions

The flowchart below reflects the decision tree followed to identify and assess Shared Asset revenue streams.
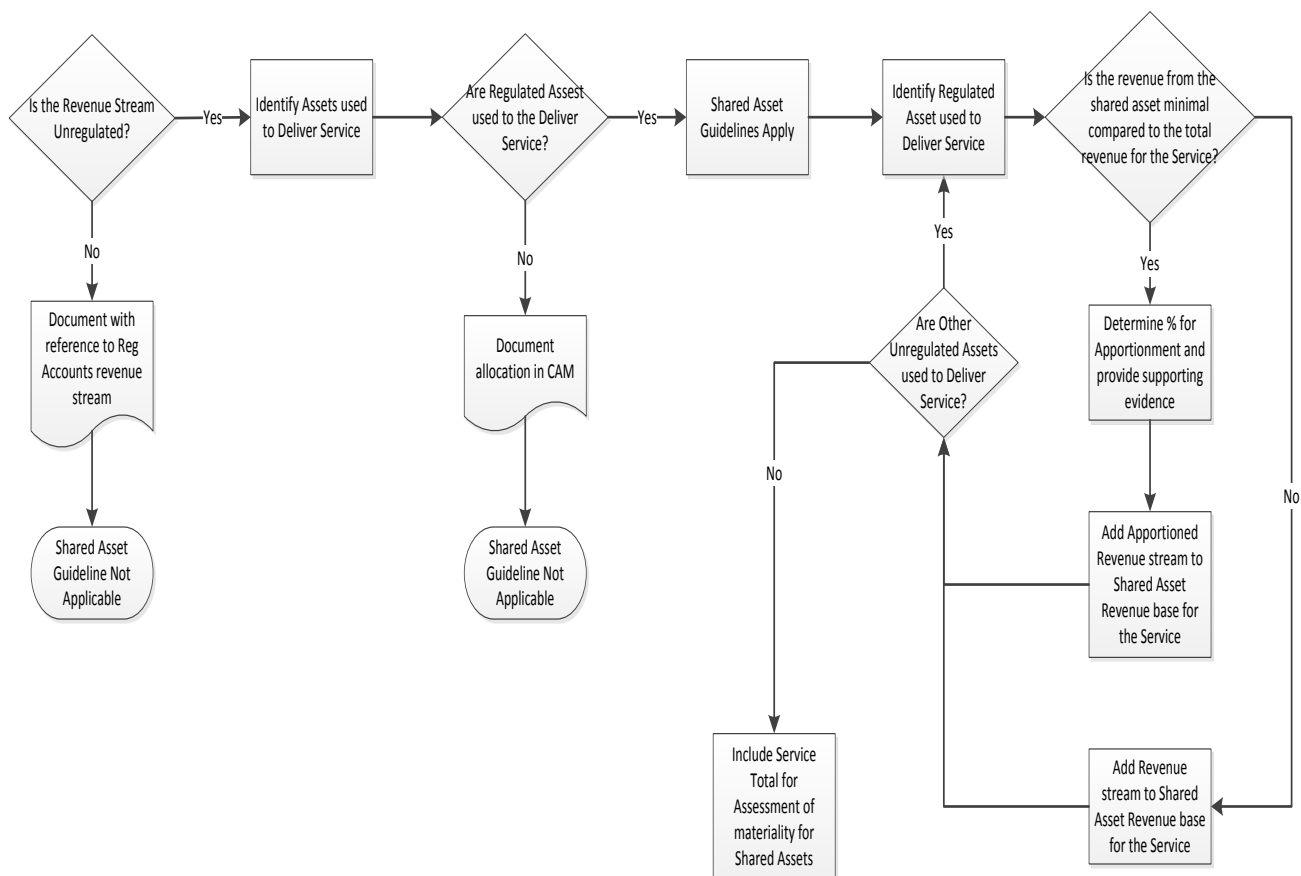
- Data Preparation and Identification of Unregulated Revenues

  Each Non-Standard Control revenue stream for 2012/13 Actual and 2013/14 Budget was mapped to a Regulatory classification using RIN submission working files

- Request for Information

  Requests were made to Commercial Managers and Business Analysts to provide analysis of the revenue streams within their area of responsibility.

- Peer Review and Further Investigations

  Responses were consolidated by the Management Accountant Labour Analytics and distributed for Peer Review.

  The following items were noted for clarification:

  o Nightwatch
    As a result of the peer review and subsequent investigations, Nightwatch revenue relating to the rental for use of Endeavour Energy Poles was reassessed as being derived from the use of Shared Assets. ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮ The use of poles is recognised as a

Shared Asset and a methodology for apportionment has been developed and described in Table 7.4.2 of our response. Lighting Assets used to provide these services are costed to an Unregulated Asset base and therefore do not constitute a shared asset.

Revenue related to the recovery of Distribution Use of System Charges will be recognised in Regulated Revenue for the forecast period.

Revenue is also attributable to the energy consumption associated with the provision of the service which makes no use of Regulated Assets.

Revenue also contributes to recovery of overheads and profit margins.

Use of poles has been determined to be minimal in the context of the overall service being provided as the use is limited to affixing the Nightwatch assets to poles, and the majority of revenue is derived from the dedicated (unregulated) Nightwatch assets.

- Assumptions

The following Key Assumptions, in addition to any implications of the above clarifications, have been made in assessing Shared Asset Revenues:

o Revenue Classification
Unregulated revenues were identified using the classification applied in the 2012/13 RIN and the results of peer review investigations.

o System Asset Cost Allocation Method (CAM)
System Assets are fully allocated to Regulated business.

o Non-System Asset CAM
The allocation of Non-System assets to the unregulated classification adequately reflects the use of Non-System assets used in the derivation of the unregulated revenue.

o Nightwatch
For the purposes of determining an appropriate level of apportionment, the value of the use of poles by the Nightwatch activity has been estimated by ███████████████████████ ███████ It is believed this represents a conservative maximum value for this component as the impost on, and use of assets, is lower for Nightwatch assets and revenues than the benchmarked - ███████████.

o NBN
NBN roll-out to continue on a similar basis to current trial agreements. Noting that Facility Access Agreements are not yet in

place, and the possibility of this activity being undertaken utilising the provisions of Schedule 3 of the Telecommunications Act.

Pole Rental fees are derived from use of Shared Assets.

Administrative fees including Application Processing and Design certification do not utilise shared assets.

- Conclusions on Revenue Streams determined to be Shared Asset Revenues

  As a result of the above process the following revenue streams have been assessed as being derived from the use of Shared Assets:
  - Nightwatch – to be apportioned
  - Property Rental (including Radio Base Stations)
  - Poles used for broadband cable
  - Duct used for broadband cable
  - Columns, Poles and Towers used for mobile phone cells

- Historical data

  Historical data was extracted from Endeavour Energy's ERP and mapped consistently with the revenue classification assumption above.

- Forecast data

  Forecast data has been derived using a combination of Endeavour Energy SCI forecasts and bottom-up activity based calculations for identified shared asset revenue streams.

  Revenues potentially sourced from NBN have been separately assessed due to the nature of this line of revenue, and the timing and availability of information required for the development of forecasts. Revenue forecasts have been based on estimates of the number of impacted poles and risers, applying revenue rates consistent with current trial agreements.

Use of estimated information

Endeavour Energy has used estimated information for deriving the value for Apportionment of Nightwatch revenue. An estimate was required as neither the data captured nor pricing structure for Nightwatch activity provided an explicit calculation of the amounts recovered in relation to pole rental. Value of the revenue attributable to use of poles by the Nightwatch activity has been estimated by applying the ▬▬▬▬▬▬▬▬▬▬▬▬▬▬▬▬▬▬ by the number of Nightwatch installations.

Reliability of information

Worksheet 7.5 – EBSS

7.5.1 Carry over amounts from 2009-10 to 2013-14

Compliance with requirements of the notice

The entries in table 7.5.1 provide the AER with the inputs required to calculate EBSS allowances.

Source of information

CPI:
  1. RIN Template pre-populated by AER

Opex Allowance Applicable to EBSS – EBSS Target (2010 – 2014):
  1. AER 2009 Determination Decision model (Tribunal Varied)

Actual and Estimated Opex Applicable to EBSS:
  1. 2010: EE's 2010 Incentive Scheme RIN Response;
  2. 2011: EE's 2011 Annual RIN Response and AER Decision - Application for a retail project event nominated cost pass through (March 2012);
  3. 2012: EE's 2012 Annual RIN Response; and
  4. 2013: EE's 2013 Annual RIN Response.

Methodology and assumptions

Endeavour Energy has made no assumptions.

Endeavour Energy has populated the inputs to this template as requested by the AER. Endeavour does not agree, however, with the calculation of EBSS carry over amounts for the 2014-19 regulatory control period as produced by this template.

The AER's Stage Two Framework and Approach Paper (January 2014) requires that Endeavour Energy use the EBBS model (model version 2). This model was published by the AER in November 2013.

Endeavour Energy notes that the calculated EBSS amounts using the prescribed model do not reflect the amounts calculated by the RIN template. Endeavour Energy will, therefore, be basing the EBSS amounts in the substantive regulatory proposal on the model prescribed in the AER's Stage Two Framework and Approach Paper.

Endeavour Energy has calculated the EBSS allowances for the substantive regulatory proposal using the same inputs as included in this RIN.

Use of estimated information

No estimated information was used in completing table 7.5.1.

Reliability of information

Worksheet 7.7 – Service and indicative prices

7.7.1 Standard control services

Compliance with requirements of the notice

The data presented in table 7.7.1 is consistent with the requirements of the Reset RIN. In particular:

- The Distribution Use of System ('DUoS') revenue and sale quantities reported in table 7.7.1 is separately disclosed for each tariff and tariff component; and

- The DUoS revenue and sales quantities reported in table 7.7.1 do not net off between distribution services.

Source of information

DUoS revenue and associated sales quantity information used to populate table 7.7.1 was extracted directly from TM1. Endeavour Energy uses this OLAP tool for various purposes including budgeting and forecasting, monthly reporting and regulatory account allocations and it has been used historically to provide data for previous audited RINs. It is a cube based technology which allows rules to be created between cubes and within cubes. More specifically, DUoS revenue and associated sales quantity information was extracted from the TM1 NUoS cube, which is used by Endeavour Energy to store, analyse and report data related to energy volumes, customer numbers and demand KW/kVA and calculate associated revenue outcomes (i.e. energy revenue, NAC revenue and demand revenue) at the network tariff level. It is the primary tool used to calculate the month end revenue accrual and report on month end results and is also used extensively for budgeting and forecasting revenue related items.

Current Prices (2010 – 2014):
1. 2010: Pricing Compliance Model FY2010 (AER Approved);
2. 2011: Pricing Compliance Model FY2011 (AER Approved);
3. 2012: Pricing Compliance Model FY2012 (AER Approved);
4. 2013: Pricing Compliance Model FY2013 (AER Approved); and
5. 2014: Pricing Compliance Model FY2014 (AER Approved).

Indicative Prices (2015 – 2019):
Post Tax Revenue Model (PTRM) - Substantive Regulatory Proposal

Methodology and assumptions

The following table sets out the methodology applied to obtain the required data for table 7.7.1. A separate methodology is presented for the population of sales quantities data and revenue data

Methodology	Assumptions
Sales Quantities	
1. The following data was extracted from the TM1 NUoS cube for the period 2009/10 to 2013/14 at the individual service rate level: • Customer days of service; • Energy consumption by chargeable quantity (i.e. step 1, step 2, peak, shoulder and off-peak); and	No assumptions were made in the extraction and presentation of sales quantity data in table 7.7.1.

• Demand kVA (in total for the year and by month). Actual data for the full year was used for the period 2009/10 to 2012/13, whereas the data for 2013/14 represented the forecast data used in the Transitional Regulatory Proposal. 2. The data at the service rate level was totalled for each quantity category and for each year and reconciled back to the total from the TM1 NUoS cube to ensure no service rates were excluded from the original data extraction. 3. Demand kVA is required to be reported separately in table 7.7.1 for high season demand and low season demand. As a result, each month was identified as either high season or low season (with reference to Endeavour Energy's Network Price List), and demand kVA was summarised each year into high season demand and low season demand. 4. Each service rate was mapped to the relevant parent tariff (as identified in table 7.7.1) by using the tariff roll-up structure in the TM1 NUoS cube. 5. Using the detailed sales quantity data at the service rate level (mapped to network tariffs), sales quantities were populated into table 7.7.1 using the following criteria: • The sales quantity for NAC is presented as total customer days of service for the tariff; • The sales quantity for 1st block energy, 2nd block energy, controlled energy, peak energy, shoulder energy and off peak energy is energy consumption by chargeable quantity presented in GWh; and • The sales quantity for high season demand and low season demand is peak demand presented in mVA. 6. A series of reconciliations were performed back to the source data and to previously reported amounts in the Benchmarking RIN to ensure information	

being reported is consistent and accurate at the total level.	
Revenue Earned	
1. The following data was extracted from the TM1 NUoS cube for the period 2009/10 to 2013/14 at the individual service rate level: • DUoS NAC revenue; • DUoS energy revenue by chargeable quantity (i.e. step 1, step 2, peak, shoulder and off-peak); and • DUoS demand revenue (in total for the year and by month). Actual data for the full year was used for the period 2009/10 to 2012/13, whereas the data for 2013/14 represented the forecast data used in the Transitional Regulatory Proposal. 2. The data at the service rate level was totalled for each revenue category and for each year and reconciled back to the total from the TM1 NUoS cube to ensure no service rates were excluded from the original data extraction. 3. DUoS demand revenue is required to be reported separately in table 7.7.1 for high season demand and low season demand. As a result, each month was identified as either high season or low season (with reference to Endeavour Energy's Network Price List), and DUoS demand revenue was summarised each year into high season demand and low season demand. 4. Each service rate was mapped to the relevant parent tariff (as identified in table 7.7.1) by using the tariff roll-up structure in the TM1 NUoS cube. 5. Using the detailed DUoS revenue data at the service rate level (mapped to network tariffs), DUoS revenue by tariff component was populated into table 7.7.1. 6. A series of reconciliations were performed back to the source data and to previously reported amounts in the Benchmarking RIN to ensure information	Immaterial differences between total DUoS revenue extracted from the TM1 NUoS cube and DUoS revenue reported in the Benchmarking RIN (which is based on previously audited Regulatory Accounts / RINs) were identified during reconciliation processes. These differences are immaterial to total DUoS revenue and as a result were added back to N70 Step 1 energy revenue to ensure total DUoS reported in table 7.7.1 reconciled to DUoS revenue reported in the Benchmarking RIN.

being reported is consistent and accurate at the total level.	

As outlined above, in populating table 7.7.1, Endeavour Energy reconciled total DUoS revenue, energy consumption and demand kW/kVA to information reported in the Benchmarking RIN and previously audited Regulatory Accounts / RINs. The Benchmarking RIN and previously audited Regulatory Accounts / RINs presented revenue and consumption data on an accrued basis. As a result, in order to reconcile the Benchmarking RIN and previously audited Regulatory Accounts / RINs, the data presented in table 7.7.1 is also presented on an accrued basis. Reporting figures on an accrued basis results in a small number of immaterial negative values for both DUoS revenue and sales quantities. This relates to customer specific network tariffs and has resulted due to historic billing adjustments which produces a credit value for the year.

Current Prices (2010 – 2014):

Current prices have been sourced from the Approved Annual Pricing Proposal for the pricing year. No assumptions have been made.

Indicative Prices:

Indicative prices have been sourced from the Substantive Regulatory Proposal Post Tax Revenue Model (PTRM). It is assumed that the annual price change is applied in a uniform manner across all tariff components.

Use of estimated information

While Endeavour Energy made an assumption in order to ensure total DUoS revenue reported in table 7.7.1 reconciles to the Benchmarking RIN (as outlined above), it has not used Estimated Information as defined in chapter 9 of the Economic Benchmarking RIN Instructions & Definitions.

Reliability of information

All the information provided represents Actual Information extracted from Endeavour Energy's reporting systems and has been reconciled to reported figures in the Benchmarking RIN. As a result, the information contained in table 7.7.1 is considered to be reliable.

7.7.2 Negotiated services

Compliance with requirements of the notice

Endeavour Energy did not have any Negotiated Services in the current regulatory control period.