AusNet Electricity Services Pty Ltd

AER Economic Benchmarking

Regulatory Information Notice

2015 Regulatory Year Basis of Preparation

Basis of Preparation

2015 Regulatory Year

1. Overview

This Basis of Preparation document supports the preparation and reporting of the 2015 Regulatory Year data presented in AusNet Electricity Services Pty Ltd ("AusNet Electricity Services") reports entitled '2015 AusNet Services economic benchmarking data - Actual Information', '2015 AusNet Services economic benchmarking data - Estimated Information', '2015 AusNet Services economic benchmarking data - Consolidated Information' and 'Other Supporting Information' ("the Reports"). The Reports provide data solely for the use of the Australian Energy Regulator ("AER") to perform benchmarking activities under the AER's Better Regulation program.

The ultimate Australian parent entity of the Company was formerly AusNet Services (Distribution) Ltd, a Company incorporated in Australia, which was part of a listed stapled group trading as AusNet Services. On 18 June 2015, AusNet Services completed a legal entity restructure under which the existing stapled entities became wholly owned by a new listed company (AusNet Services Ltd). As a result of the restructure, the ultimate parent of the Company is AusNet Services Ltd.

The Reports have been prepared in accordance with the 'Regulatory Information Notice issued under section Division 4 of Part 3 of the National Electricity (Victoria) Law' ("RIN") issued by the AER on 28 November 2013, the accompanying 'Economic Benchmarking RIN for distribution network service providers - Instructions and Definitions' issued by the AER and other authoritative pronouncements of the AER. AusNet Electricity Services' 2015 regulatory year is the period 1 January 2015 to 31 December 2015 ("Regulatory Year"). Data included in the Reports has been provided for the 2015 Regulatory Year. All financial data included in the Reports is presented in Australian dollars. Non-financial data is stated as per the measures specified in the Reports.

The AusNet Services' Group owns and operates 3 regulated networks – an electricity distribution network, a gas distribution network, and an electricity transmission network. Employees of the AusNet Services Group work across the 3 regulated networks and there are shared costs and overhead and other corporate costs that cannot be directly allocated to a particular network. These costs are proportioned amongst AusNet Services' 3 regulated networks, as well as unregulated businesses, based on an Activity Based Costing ("ABC") survey process completed by all cost centre managers and in accordance with AusNet Services' Cost Allocation Methodology ("CAM"). For the first 4 months of the 2015 regulatory year this was completed on a quarterly basis and for the remaining 8 months, it was completed monthly on a reviewed and streamlined cost centre structure.

Materiality has been applied throughout the Reports and Basis of Preparation. Materiality is defined as information that if omitted, misstated or not disclosed has the potential, individually or collectively to influence the economic decisions of users.

The Reports require inputs to be allocated between Standard Control Services and Alternative Control Services.

Standard Control Services are defined as per the National Electricity Rules ("NER"). For clarity, Standard Control Services capture services only available through the network (typically provided to all customers or a broad class of customers) recovered through general network tariffs.

Alternative Control Services are defined in the NER. By way of context, Alternative Control Services are intended to capture electricity distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Alternative control services are electricity distribution services that are a direct control service but not a standard control service.

The AER's requirements, applicable to the current regulatory year, is to report all variables as Actual Information, unless a variable is expressly allowed to be reported as Estimated Information under the RIN guidelines. Interpretation of the AER's definition of Actual and Estimated information requires management judgments to be made as to the appropriate classification of information including:

- the extent to which the information is sourced from accounting or other records used in the normal course of business; and
- the degree of estimation involved and whether the information is materially dependent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation.

The methodologies, assumptions and judgments made by management in respect of variables are described within the relevant sections of this Basis of Preparation.

Where estimated information has been presented, the circumstances and the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is AusNet Electricity Services' best estimate has also been set out below. Estimates are considered to be managements' best estimate based on the data available. Estimates will often not equal the related actual results and estimates have only been made for the purpose of disclosing the information required under the RIN. Considerations of the cost and efficiency of preparation as well as the reliability and accuracy of data available have been taken into account in determining the best methodology to determine the estimates.

'Actual Information' is defined as information materially dependent on information recorded in historical accounting records or other records used in the normal course of business, and whose presentation is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation. Any information or allocation which has been calculated via the ABC survey process is considered actual information, as this is in accordance with the AER-approved CAM.

AusNet Services implemented a new Enterprise Resource Planning system (SAP) effective 4 May 2015. Therefore, in many instances, the data presented in the Templates has been sourced (for the January to April months period) from the same systems as used for the 2014 Annual Regulatory Accounts submission; and the May to December months period data has been sourced from the new system. The new system consolidates a number of systems and was designed to record more accurate data in a manner to support the preparation of the Regulatory Accounts, this has had no impact on the CAM. When referring to Financial Systems, the first 4 months refers to Oracle and the remaining 8 months refers to SAP. These circumstances have been explained in the basis of preparation where applicable.

To the extent applicable, the information reported has been prepared in a manner consistent with the policies and methodologies applied in preparing the Annual Regulatory Accounts. There were no changes in Accounting Policies during the 2015 Regulatory Year which had a material impact on the information presented.

Basis of Preparation

2015 Regulatory Year

The preparation methodologies and information sources adopted in the preparation of the Reports are set out below.

Contents

3.1 Revenue

Distribution Use of Systems Revenue (“Revenue”) is measured at the fair value of the consideration received or receivable, net of the amount of Goods and Services Tax (“GST”) payable to the taxation authority. Revenue is recognised as the services are rendered and is reported inclusive of incentive scheme penalties and rewards. Total Revenue is disaggregated by chargeable quantity and also by customer class.

There have been no material changes to the accounting policies adopted by AusNet Electricity Services in relation to Revenue during the 2015 Regulatory Year in comparison to previous Regulatory Years reported.

Table 3.1.1 Revenue grouping by Chargeable Quantity

Revenue reported has been classified into the chargeable quantity which most closely reflects the basis upon which the revenue was charged to customers. Where it has been determined that Revenue cannot be allocated to the specified chargeable quantity classifications in DREV0101 to DREV0112, Revenue has been reported against ‘Revenue from other Sources’ (DREV0113).

<u>Preparation Methodology</u>:

Standard Control:

Revenue by distribution tariff was sourced from the 2015 Annual Regulatory Accounts and allocated into the categories presented using Distribution Use of System (“DUOS”) tariff schedules.

Amounts included as ‘Revenue from other Sources’ relate to summer export payments made to customers for solar feed-in which forms part of DUOS Revenue reported in the 2015 Annual Regulatory Accounts.

Alternative Control:

Revenue was sourced from the 2015 Annual Regulatory Accounts and allocated into the categories presented.

Table 3.1.2 Revenue grouping by Customer Type or Class

Revenue reported has been classified into the Customer Type or Class which most closely reflects the customers from which revenue was charged. Where it has been determined that Revenues cannot be allocated to the specified Customer Type in DREV0201 to DREV0205, Revenue has been reported against ‘Revenue from other Customers’ (DREV0206).

<u>Preparation Methodology</u>:

Standard Control:

Revenue reported in Standard Control Table 3.1.2 was allocated into customer type or class based on DUOS tariff schedules.

Alternative Control:

Revenue reported in Alternative Control Table 3.1.2 was allocated in total to Revenue from Other Customers as the Revenue cannot be allocated to the specified chargeable quantity classifications in DREV0201 to DREV0205 based on the information available.

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

The penalties or rewards from the service target performance incentive scheme (“STPIS”) or efficiency benefit sharing scheme (“EBSS”) have been reported based on the year that the penalty or reward was applied, not the year in which it was earned. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the STPIS or EBSS schemes have been reported against the applicable scheme category.

<u>Preparation Methodology</u>:

Information was sourced from 2015 Annual Regulatory Accounts, Annual Tariff Submissions & Post Tax Revenue Model.

EBSS:

EBSS revenue or penalties were calculated by smoothing the calculated nominal EBSS allowance over the 5 year period from 2011 to 2015 based on the Smoothed Revenue profile in the 2011 to 2015 Post Tax Revenue Model. EBSS Revenue was collected in accordance with the allowances and penalties prescribed for the applicable 5 year Revenue determination period.

STPIS:

STPIS was calculated by dividing the total reported DUOS revenue by (1+ incentive scheme rate) and reporting the resultant difference between reported Revenue and this adjusted Revenue as STPIS. STPIS Revenue was collected in accordance with the incentive scheme rate prescribed by the AER for the applicable period.

S-Factor:

A proportion of annual revenue has been attributed to the nominal S–Factor true up included in the 2011-15 revenue requirement reflecting the close out of the previous ESC S-Factor regime. To calculate the impact in each of the years, the total S-Factor true up over the five years was allocated to individual years based on the Smoothed Revenue profile in the 2011 to 2015 Post Tax Revenue Model. This approach most accurately reflects the years in which the revenue was generated. Management has assumed that applying a single S-Factor percentage to all DUOS revenue derives incentive revenues.

F-Factor:

F-Factor revenue is recovered by AusNet Electricity Services via the addition of approved pass through tariffs to DUOS prices. For the 2015 Regulatory Year, AusNet Electricity Services’ pass through tariffs sought to recover amounts not only attributable to F-Factor incentives, but also costs associated with implementing the Victorian Bushfire Royal Commission (VBRC) recommendations. To calculate the revenue received under the F-factor regime, AusNet Electricity Services multiplied the quantities against each tariff code as reported in the 2015 Annual Regulatory Accounts by the approved pass through tariffs for each tariff code. This calculates total pass through revenue, which was then apportioned between VBRC and F-Factor using the pass through costs sought for both pass throughs in the 2015 network price submission.

Estimated Information:

No Estimates were required.

3.2 Operating expenditure

Operating Expenses ("Opex") are the costs of operating and maintaining the network (excluding all capital costs and capital construction costs). The categorisation of Opex is presented in accordance with the Cost Allocation Methodology ("CAM") which is materially consistent with the previous Regulatory Years. Only those costs that are disclosed as 'operating expenses' and 'maintenance' in the 2015 Annual Regulatory Accounts have been included in the opex tables in section 3.2. All other expenses have been excluded.

AusNet Services owns and operates 3 regulated networks – an electricity distribution network, a gas distribution network, and an electricity transmission network. Opex that is incurred for a particular network is allocated directly to that network. Overhead costs that cannot be directly allocated to a particular network are proportioned amongst AusNet Services' 3 regulated networks as well as unregulated businesses via an Activity Based Costing ("ABC") survey process completed by all cost centre managers and in accordance with AusNet Services' CAM.

The accounting policies adopted by AusNet Electricity Services in relation to Opex have not materially changed in comparison to prior years.

Table 3.2.1.1 Current opex categories and cost allocations

Preparation Methodology:

In accordance with the requirements of the RIN, Table 3.2.1.1 is only required to be completed where there has been a material change in AusNet Services' CAM, annual reporting requirements or basis of preparation for its 2015 Annual Regulatory Accounts. There have been no material changes in the 2015 Regulatory Year. Based on this, Table 3.2.1.1 is not required to be completed.

Table 3.2.1.2A Historical opex categories and cost allocations

Opex categories and allocations have been presented as per the categories in the 2015 Annual Regulatory Accounts and in accordance with requirements of the CAM, the Annual Regulatory Accounts and the Annual Reporting Requirements. Opex for Standard Control Services and Alternative Control Services reconciles to operating expenses and maintenance as disclosed in the 2015 Annual Regulatory Accounts.

Preparation Methodology:

Using data extracted from the 2015 Annual Regulatory Accounts, operating expenses were allocated into the categories applicable for the 2015 Regulatory Year.

Data was sourced from the Maintenance Expense and Operating Expense templates of the 2015 Annual Regulatory Accounts. The Standard Control Services figures shown include Advanced Metering Infrastructure ("AMI").

Estimated Information:

No estimates were required.

Table 3.2.2 Opex consistency: Table 3.2.2.1 Opex consistency - current cost allocation approach

In accordance with the requirements of the RIN, Table 3.2.2.1 is only required to be completed where there has been a material change in AusNet Services' CAM, annual reporting requirements or basis of preparation for its Annual Regulatory Accounts. There have been no material changes in the 2015 Regulatory Year. Based on this, Table 3.2.2.1 is not required to be completed.

Table 3.2 Opex consistency: Table 3.2.2.2 Opex consistency - historical cost allocation approaches

Opex has been allocated in accordance with the categories required and in accordance with the requirements of the CAM, the Annual Regulatory Accounts and the Annual Reporting Requirements that were in effect for the individual Regulatory Year. The Opex categories presented in this table are not intended to be mutually exclusive or collectively exhaustive. The Standard Control Services figures shown include AMI.

Preparation Methodology:

In relation to Standard Control Opex, data was extract from the financial systems. Operating expenses were allocated into the categories prescribed based on cost ledger code. Each code was reviewed by a subject matter expert and, where possible, a one-to-one relationship was identified between the ledger cost code in the financial system and the regulatory category in Table 3.2.2.2.

For those ledger cost codes where a one-to-one relationship with a regulatory category in Table 3.2.2.2 could not be identified, the costs associated with that cost code were allocated to the various regulatory categories based on the most appropriate causal allocator as identified through the ABC Survey process.

Any costs which are not applicable in accordance with the regulatory accounting guidelines such as Interest, Income Tax Expense and contestable activities are excluded from the allocation process.

In relation to Transmission Point Planning Opex, the data reported was obtained via the ABC survey process and reflects the salary costs of the employees involved in transmission point planning scaled by the portion of their time spent undertaking such activities.

In relation to Alternative Control Opex, data was extracted from the 2015 Annual Regulatory Accounts and allocated into the categories applicable for the 2015 Regulatory Year.

Estimated Information:

No estimates were required.

Table 3.2.4 Opex for high voltage customers

Opex for high voltage customers has been reported based on the amount of Opex that would have been incurred in maintaining the electricity distribution transformers which are owned by high voltage customers.

Preparation Methodology:

Actual Information is unavailable; therefore an estimate has been derived based on the Opex incurred for operating similar MVA capacity Distribution Transformers within the network. AusNet Electricity Services has high voltage customers who are supplied electricity at the higher voltage ratings of 6.6kV, 12kV and 22kV as well as sub transmission customers who are supplied electricity at 66kV.

The estimate has been calculated as the total cost of maintaining all owned transformers, divided by the number (units) of owned transformers. The resultant average cost is multiplied by the number of customers. This calculation relies on the assumption that Opex for high voltage customers is in line with Opex incurred for similar activities by AusNet Electricity Services.

Estimated Information:

For customers who are supplied electricity at 6.6kV, 12kV and 22kV, average unit cost is derived based on AusNet Electricity Services' estimated cost to maintain high voltage distribution substations, apportioned based on the capacity and number of substations.

It should be noted that this is an estimate based on AusNet Electricity Services' estimated cost to maintain substations. It has been assumed that the cost of maintaining each type of substation (for example mounted substations, kiosk substations, ground type and indoor) is identical as maintenance costs are not available by substation type. It has also been assumed that the customer substations are similar in design to AusNet Electricity Services' substations. This is considered a reasonable assumption as substation designs across Victoria are generally similar.

As a licensed distribution company operating under an Electricity Safety Management Scheme (ESMS), AusNet Electricity Services has significant economies of scale. Therefore, a customer would spend more on average to maintain a substation. Hence, an additional calculation is performed to scale up the unit cost based on what a customer may be expected to pay to maintain a larger substation (e.g. 500kV). An average unit cost has then been applied to estimate the total Opex associated with these customers.

Among the customers who are supplied electricity at 66kV, one is similar in size to that of a typical AusNet Electricity Services zone substation, and as such, the unit cost is estimated to be similar to AusNet Electricity Services' average Opex cost for a typical zone substation. For the other 66kV customers that are lesser in size, their average Opex cost is assumed to be half of that of a typical AusNet Electricity Services' zone substation – reflecting the reduction in the size of the substation and a reduction in the complexity of the associated maintenance costs.

Information was obtained from the financial system and the billing system. For consistency and comparability, information from the 2012 Regulatory Year was used as that was also the basis to estimate the data applied to the submission for Regulatory Years 2010 - 2015, adjusted based on customer numbers and the Consumer Price Index applicable to the 2015 Regulatory Year. This is considered to be management's best estimate based on the data available.Based on the RIN Instructions and Definitions, this metric is permitted to be "Estimated Information" on an ongoing basis.

3.2.3 Provisions

Provisions are recognised when AusNet Electricity Services has a present legal or constructive obligation as a result of past events, it is more likely than not that an outflow of resources will be required to settle the obligation, and the amount of the provision can be measured reliably. Provisions are not recognised for future operating losses.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the relevant reporting date, taking into account the risks and uncertainties surrounding the obligations. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

Financial information on provisions for Standard Control Services has been reported in accordance with the requirements of the CAM. The Standard Control Services figures presented include AMI.

Provisions have been separately presented based on the nature of the provision and allocated between an Opex component and a Capital Expenditure ("Capex") component based on the classification of the underlying cost associated with the provision.

Table 3.2.3 –Provisions

<u>Preparation Methodology</u>:

Provision - Uninsured Losses, Provision – Environmental Provisions, Provision - Customer Rebates, Provision – Miscellaneous, Provision – Make Good, Provision – Other and Provision – Doubtful Debts

Data was extracted from the financial and allocated into Standard Control Services and AMI based on appropriate drivers. Examples of drivers include the percentage of total SCS operating and maintenance expenditure per the 2015 Annual Regulatory Accounts.

Information disclosed in relation to the above provisions is considered 'actual information'.

Provision - Superannuation and Provision - Employee Entitlements

The amounts reported in the 'Provision - Employee Entitlements' table relate to liabilities for wages and salaries, including non-monetary benefits and annual leave recognised in respect of employees' services up to the reporting date and are measured at the amounts expected to be paid when the liabilities are settled.

Data was extracted from the financial systems and allocated into Standard Control Services and AMI based on Headcount drivers sourced from the ABC surveys.

The total 'Amounts used during the period' and 'Unused amounts reversed during the period' disclosed are considered 'actual information' as the data was extracted from the financial system. All other information disclosed under Provision - Superannuation and Provision - Employee Entitlements is considered 'estimated information'. To derive the estimates, information was sourced from the financial system and supplemented with internal allocation models based on ABC surveys.

For Provision - Employee Entitlements and Provision - Superannuation, the split between the Opex component and the Capex component was estimated. To determine the proportion of these provisions that should be classified as Capex, AusNet Electricity Services has used the results from the AusNet Services Group quarterly (Oracle data) and monthly (SAP data) capitalised overhead model which calculates the proportion of labour costs to be capitalised. The quarterly/monthly capitalised overhead model uses results from the ABC surveys which provide the percentage split of management effort between all of AusNet Services' regulated and unregulated networks as well as between Opex and Capex.

Estimated Information:

In relation to Provision - Employee Entitlements and Provision - Superannuation, the split between the Opex component and the Capex component was estimated as the data is not separately captured in the financial systems.

This is considered to be Management's best estimate based on the data available.

3.3 Assets (RAB)

The Regulated Asset Base (“RAB”) values have been prepared and reported as per AusNet Electricity Services’ interpretation of the AER instructions set out in Section 4 of the RIN Instructions and Definitions (“RIN I&Ds”).

Opening RAB values have been sourced from the 2014 Economic Benchmarking RIN and adjusted to reflect amendments included in AusNet Services’ Revised Proposal Roll Forward Model (submitted to the AER on 6th January 2016). The amendments relate to historical asset disposals reported in Regulatory Years 2012 and 2013 affecting multiple RAB categories. These amendments are discussed further in AusNet Services’ Revised Regulatory Proposal.[1] Additionally, Equity raising costs that were approved by the AER in the 2011-15 Distribution determination and included in AusNet Services’ RAB are reported under Standard Control Services (previously omitted in historical Distribution benchmarking RINs).

The accounting policies adopted by AusNet Electricity Services in relation to capex (the only regulatory accounting input into the RAB) have not materially changed during the 2015 Regulatory Year compared to previous Regulatory Years reported.

Table 3.3.1 Regulatory Asset Base Values

The RAB values have been prepared and reported as per AusNet Electricity Services’ interpretation of the AER instructions set out in Section 4 of the RIN I&Ds.

Preparation Methodology:

The 2014 AusNet Services’ Economic Benchmarking RIN was used as the basis for opening RAB values, as there has been no more recent AER determination of RAB values than those used as the basis for the 2014 RIN response.

Data on actual additions and disposals have been reconciled to the supporting workpapers to the Annual Regulatory Accounts for the 2015 Regulatory Year. For actual additions, under Standard Control and Network Services, values include a 6-month nominal WACC allowance consistent with the treatment of additions in the AER’s Roll Forward Model.

Straight-line depreciation, reported at DRAB0103, is based on forecast straight-line depreciation, per the 2011-15 Final decision (expressed in real 2010 dollars), adjusted for actual inflation.

Estimated Information:

AusNet Electricity Services considers that the proportion of the distribution assets that are dedicated connection assets is small. It has been assumed the customer contribution has more than fully funded customers’ dedicated assets. Therefore, subject to the removal of metering and public lighting assets, the capex included in the Standard Control Services and the Network Services Tables is equal. This data is considered to be managements’ best estimate based on the data available. Based on the RIN

[1] CH. 8: Opening Regulatory Asset Base, AusNet Electricity Services Pty Ltd, Revised Regulatory Proposal 2016-20, pp. 260-261.

Instructions and Definitions, this information is permitted to be "Estimated Information" on an ongoing basis.

Table 3.3.2 Asset value Roll forward

The disaggregated RAB values have been constructed as per AusNet Electricity Services' interpretation of the AER instructions set out in Section 4 of the RIN I&Ds.

AusNet Electricity Services has recorded assets in the RAB in asset classes that do not allow a direct attribution into the AER's economic benchmarking RAB Asset classes for the majority of assets.

Therefore, where direct attribution is not possible, AusNet Electricity Services has utilised the standard approach outlined Section 4.1.1 of the RIN I&Ds.

Preparation Methodology:

Information has been sourced from Asset Management Systems, 2012 Replacement Expenditure ("Repex") model (model template provided by the AER), the Distribution determination 2011–15, and supporting workpapers to the 2015 Annual Regulatory Accounts.

The following process was followed:

1. Opening RAB values have been sourced from the 2014 Economic Benchmarking RIN, consistent with the RIN I&Ds, including opening RAB amendments that are reflected in AusNet Services Revised Proposal RAB roll forward model (2011-15) submitted to the AER in January 2016.
2. Split between Standard Control Services, Network Services, and Alternative Control Services:
    a. Network Services and Standard Control Services exclude public lighting and meters as instructed by the AER
    b. Alternative Control Services – only public lighting assets post 2005 are included in this category.
3. Table 3.3.1 was directly disaggregated into the available RAB categories from the Roll Forward Model (column 1 in the table below):

Table RAB1

Roll Forward RAB categories	Benchmarking RIN categories
Distribution	Overhead network assets less than 33kV (wires and poles)
	Underground network assets less than 33kV (cables)
	Distribution substations including transformers
Sub-transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)
	Underground network assets 33kV and above (cables, ducts etc.)
	Zone substations and transformers
Meters	Meters

Equity Raising Costs	“Other” assets with long lives
Public Lighting (ACS)	“Other” assets with long lives
Non Network, IT and SCADA assets	“Other” assets with short lives

Hence, additions and disposals were directly attributed into column 1 (above) categories, reconciling to the 2015 Annual Regulatory Accounts, and Straight Line depreciation reconciled to forecast depreciation from AusNet Services’ Distribution determination 2011–15.

4. Further disaggregation of the RAB from the Roll Forward RAB categories in column 1 (above) to those in column 2 (above) was based on two distinct approaches applied separately to depreciation and additions as follows:-

   <u>Straight Line Depreciation</u> – allocation of straight line depreciation from RAB roll forward categories into RIN categories is made by using weightings for the depreciated replacement cost for each asset category from the 2014 Repex model. This method is consistent with the disaggregation applied in AusNet Services’ 2014 Economic Benchmarking RIN. This process is described in further detail below.

   a. The allocation applied to aggregate Repex categories to the Benchmarking RIN categories is as per the table below. Engineering assessment was the basis for determining to which of the Benchmarking categories each of the asset types in the Repex model belonged to. Where it was not possible to determine based on the name for the asset type (e.g. whether poles were assets for greater than 33kV), assumptions were made as detailed below.

Table RAB2

Roll forward RAB categories	**Benchmarking RIN categories**	**Repex**
Distribution (assets less than 33kV)	Overhead network	Includes poles, crossarms, conductor and services. • Cross arm assets are distinguishable in Repex between <33kV and >33kV. This share is used to allocate other categories. • Poles – assumes share is same as cross arms (94%). • Conductor – assumes total volume is same as share of cross arms. 100% ABC and HV Steel. Remainder of other conductor categories (ACSR, AAC and CU) that are not allocated to overhead >33kV (see below). • Services – 100% are <33kV
	Underground network	Includes HVXLPE, LVXLPE, HV Paper lead, and underground services.
	Distribution substations	Includes Distribution transformers, distribution switchgear, and distribution ‘other assets’.

	including transformers	
Sub-transmission (assets 33kV and above)	Overhead network	Includes poles, crossarms and conductor Refer to notes for <33kV. • Conductor – total share by volume is based on share for crossarms. Allocation by conductor type is: 53% AAC, 47% ACSR and 1% Copper based on analysis of asset data (survey performed by external expert in prior 5 years).
	Underground network	Very small quantities identified in 2014 data, but with zero depreciated replacement value.
	Zone substations and transformers	Includes zone transformers, zone switchgear, and zone 'other assets'.

b. To disaggregate the Roll Forward RAB categories using the physical assets, depreciated replacement costs for Benchmarking RIN categories have been calculated using the following formula:

No. of Units x Unit Replacement Cost x Remaining Life/Standard Life

and then the weightings based on these values are used to split the RAB categories into the asset categories in Table 3.3.2 (column 2, Table RAB2, above). Units are from asset data in the Repex model. Unit replacement costs and standard lives are based on engineering assessment and have been updated to reflect recent review of unit rates for the EDPR capex forecasts and asset lives used for asset replacement modelling. Remaining life is calculated in the Repex model based on installation date and standard life.

Additions – the allocation of actual additions from RAB roll forward categories into RIN categories is based on additions information contained in RIN Templates 2.2 Repex, 2.3 Augex and 2.5 Connections. In some instances the judgment of an SME was used to apportion additions into the relevant benchmarking RIN categories.

Estimated Information:

Data provided in Table 3.3.2 for Network Services and Standard Control Services is considered estimated information with the exception of Meters, Other Assets with Long Lives and Other Assets with Short Lives where the information is considered actual information.

This is considered to be Management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this information is permitted to be "Estimated Information" on an ongoing basis.

Table 3.3.3 Total disaggregated RAB asset values

Preparation Methodology:

The total disaggregated RAB values were calculated as the average of the Opening Value and Closing Value for each categorisations of assets presented in Table 3.3.2.

Estimated Information:

The data provided is considered estimated information with the exception of Meters, Other Assets with Long Lives, Other Assets with Short Lives and Capital Contributions. The data provided is considered to be Management's best estimate based on the data available. Based on the RIN I&D, this data is permitted to be "Estimated Information" on an ongoing basis.

Table 3.3.4 Asset lives

Preparation Methodology:

Table 3.3.4.1 Asset Lives – estimated service life of new assets

Data reported as the 'estimated service life of new assets' is consistent with the information reported in the 2014 Assets (RAB Template). The data reported was reviewed by a SME and no changes were required for the 2015 Regulatory Year. The 2014 data was sourced from the AER Repex model which provided a weighted average life for grouped assets. The Repex model data was grouped to align to the Asset Groups required for Table 3.3.4.

Asset class specific assumptions are:

- DRAB1401: Overhead conductors, poles and pole top structures less than 33kV
- DRAB1402: Underground conductors less than 33kV
- DRAB1403: Distribution substations including all distribution transformers
- DRAB1404: Overhead conductors, poles and pole top structures above 33kV
- DRAB1405: Underground conductors above 33kV
- DRAB1406: Zone substation transformers, station service and instrument transformers

The above methodology was able to be utilised for assets in variables DRAB1401-DRAB1406. Engineering technical expertise was applied in determining WALs in the Repex model. In some instances the weighted average remaining lives ("WARL") calculated by the Repex model were negative values (as a result of data quality issues with age profiles). In these circumstances the Repex model was modified to replace negative remaining lives in each asset category to zero remaining lives.

For variables DRAB1407 'Meters' and DRAB1408 'Other assets with long lives', over the period for which data are provided, no new assets were being added to the Standard Control Services RAB. For Meters this was due to the roll out of the AMI program in Victoria. The only assets in DRAB1408 are Public Lighting, which is no longer a Standard Control Service but assumed as Alternative Control Services. The WAL and WARL were calculated using the 2014 Repex model as described above.

DRAB1409 'Other assets – Short lives' was calculated using the Repex model, which comprises field devices, local network wiring assets and communication network assets.

Table 3.3.4.2 Asset Lives – estimated residual service life

The 'estimated residual service life' of the asset group or category, was calculated based on data reported in Template 5.2 Asset Age.

The Asset Installation dates included in Template 5.2 Asset Age were used to calculate the Average Asset Lives in each of the Asset Categories. The 'Estimated Residual Service Life' was calculated as the difference between the 'Estimated Service Life of New Assets' and the Average Asset Lives.

The data provided is considered estimated information as it is based on estimated information included in Template 5.2 Asset Age.

<u>Estimated Information:</u>

Data for Asset Lives is considered estimated information. Estimates and assumptions have been outlined above. This is considered to be management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this information is permitted to be "Estimated Information" on an ongoing basis.

3.4 Operational Data

Table 3.4.1 Energy delivery

Energy delivered is the amount of electricity transported out the network in the relevant period and is measured as the energy metered (or estimated) at the customer charging location.

Preparation Methodology:

- Total Energy Delivered: This data was obtained from the billing system.

- 3.4.1.1 Energy delivery by chargeable quantity: For the 2015 Regulatory Year, tariff quantity data sourced from the Annual Regulatory Accounts was allocated to the categories required by assigning tariffs to a specific chargeable quantity.

  Energy delivered to customers on tariffs that do not have peak, shoulder or off-peak periods was reported in 'Energy Delivery where time of use is not a determinant', DOPED0201.

- 3.4.1.2 Energy – received from TNSP and other DNSPs by time of receipt: The data required was calculated based on National Energy Market Meters which record all energy flowing into and out of the transmission connections point, cross boundaries and from embedded generators.

  Total energy received has been included in DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times without a specific definition of those time periods (AusNet Electricity Services has multiple peak and off-peak time periods across its tariff classes, it is not possible to determine which 'peak' time (for example) should be used.

- 3.4.1.3 Energy – received into DNSP system from embedded generation by time of receipt: The non-residential data required was calculated based on information directly extracted from National Energy Market Meters. Energy from residential embedded generation is a combination of billed energy as well as interval data energy for customers that are not billed for generation into the network.

  Total energy received from non-residential embedded generation has been included in DOPED0404 'Energy received from embedded generation not included in above categories from non-residential embedded generation' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times without a specific definition of those time periods.

  Total energy received from residential embedded generation has been included in DOPED0408 'Energy received from embedded generation not included in above categories from residential embedded generation' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times.

- 3.4.1.4 Energy grouping – customer type or class: Tariff quantity data sourced from the Annual Regulatory Accounts (which was ultimately sourced from customer billing data) was allocated to the categories required by assigning each tariff to a specific customer type or class.

Unmetered energy delivery was reported in ‘Other Customer Class Energy Deliveries’ [DOPED0505].

Table 3.4.2 Customer numbers

Distribution Customers for a Regulatory Year are defined as the average number of energised and de-energised National Meter Identifiers (“NMIs”) in AusNet Electricity Services’ network in that year, plus unmetered customers but excluding extinct NMIs. The average is calculated as the average of the number of customers on the first day of the Regulatory Year and the last day of the Regulatory Year.

For unmetered customers, Customer Numbers are the sum of connections (excluding public lighting connections) that do not have a NMI and the energy usage for billing purposes is calculated using an assumed load profile (examples include bus shelters, security lighting and traffic signals where not metered). Public lighting connections are not included as unmetered customers.

<u>Preparation Methodology</u>:

The total average customer numbers were obtained from extracts from AusNet Services’ SAP Customer Information System. The split of customer numbers into the prescribed categories was estimated as follows -

- Table 3.4.2.1 Distribution customer numbers by customer type or class: total average customer numbers were allocated into the prescribed customer types using a percentage allocation based on tariff classification data from Tariff Schedules (included in the 2015 Annual Regulatory Accounts and Tariff Submissions).

  ‘Unmetered customer numbers’ (DOPCN0105) was obtained directly from the New Connections Unmetered Supplies (“UMS”) database. This database has undergone a clean-up in 2015 and consequently, the number of unmetered customers has increased relative to prior years.

- Table 3.4.2.2 Distribution customer numbers by location on the network: Using data extracted from the Service Order Management System, the percentage of customers by the three feeder categories (Urban, Short Rural and Long Rural) was obtained. These percentages were applied to the total average customer numbers per Table 3.4.2.1 to derive an estimate of distribution customer numbers by location on the network.

  The categorisations are based on the feeder locations (Urban, Short Rural and Long Rural) in the 2015 Regulatory Year.

Table 3.4.2.4 is obtained from DOPCN0105 and Table 3.4.2.3 is not applicable to AusNet Electricity Services.

<u>Estimated Information</u>:

The categorisations of customers into the required categories are not available from the Customer Information System.

The categorisation of customers in Table 3.4.2.1 (with the exception of 'Unmetered Customer Numbers') and the categorisation of customers in Table 3.4.2.2 are considered estimated information due to the application of percentages to derive the requested data categorisations.

This is considered to be management's best estimate based on the data available. **Table 3.4.3 System demand – Tables 3.4.3.1, 3.4.3.2, 3.4.3.3 and 3.4.3.4**

Preparation Methodology:

- Table 3.4.3.1 Annual system maximum demand characteristics at the zone substation level.

  Daily non-coincidental maximum demand data was extracted from OSI Pi. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for 2015.

  30 minute maximum demand data was extracted from OSI Pi for each zone substation, providing daily coincidental maximum demand information (date, time). Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for 2015.

- Table 3.4.3.2 Annual system maximum demand characteristics at the transmission connection point – MW measure.

  Non-coincident Summated Raw System Annual Maximum Demand:

  AusNet Electricity Services has calculated demand based on National Energy Market Meter data supplied from the transmission business.

  Coincident Raw System Annual Maximum Demand:

  Information was sourced from the National Energy Market Meters (Both Terminal Station, Boundary and Generator Meters). The network meters have been reconciled with AEMO and AusNet Services' Protection department to ensure all applicable meters are accounted for in calculating the Maximum Demand on the network.

  Daily coincidental maximum demand data was extracted for the network for all days in 2015. Using this information, the maximum demand day was identified for each year. Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) was identified.

- Table 3.4.3.3 Annual system maximum demand characteristics at the zone substation level – MVA measure.

  Daily non-coincidental maximum demand data was extracted from OSI Pi. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for 2015.

30 minute maximum demand data was extracted from OSI Pi for each zone substation, providing daily coincidental maximum demand information (date, time). Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for 2015.

- Table 3.4.3.4 Annual system maximum demand characteristics at the transmission connection point – MVA measure.

Non-coincident Summated Raw System Annual Maximum Demand:

AusNet Electricity Services has calculated demand based on National Energy Market Meter data supplied from the transmission business.

Coincident Raw System Annual Maximum Demand:

Information was sourced from the National Energy Market Meters (Both Terminal Station, Boundary and Generator Meters). The network meters have been reconciled with AEMO and AusNet Services' Protection department to ensure all applicable meters are accounted for in calculating the Maximum Demand on the network.

Daily coincidental maximum demand data was extracted for the network for all days in 2015. Using this information, the maximum demand day was identified for each year. Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) was identified.

Weather adjusted Maximum Demand (all reporting lines)

AusNet Services' POE10 and POE50 demand forecasts are developed at a feeder level. Each feeder has its own temperature-demand relationship calculated, resulting in an 's-curve' for each feeder (where demand increases with temperature on a non-linear basis and then saturates once the temperature reaches a certain point). This means that at a zone substation level, weather-correcting demand data is a very complex process. For RIN reporting purposes, weather correction uses the average of five feeders' s-curves (PHM33, CLN23, BDL4, BGE22, BN1) to estimate the temperature-demand relationship for all zone substations.

The following methodology has been used to estimate weather-corrected demand:

- Assign each zone substation to one of AusNet Services' three regions: central, east and north.
- Obtain daily maximum temperature data from the Bureau of Meteorology for three weather stations within these regions: Scoresby Research Institute (central), East Sale Airport (east), Wangaratta Aero (north).
- If the zone substation is winter-peaking, assume that the weather-corrected demand is the same as the recorded demand.
- If the zone substation is summer peaking, but the temperature on the date that maximum demand was recorded was below 23 degrees, assume that the weather-corrected demand is the same as the recorded demand.

- If the zone substation is summer peaking and the temperature on the date that maximum demand was recorded was above 23 degrees:
    - Divide the recorded demand by a ratio of (1) the position on the averaged s-curve for the temperature on the maximum demand day and (2) the relevant POE temperature (38 degrees for POE50 and 46 degrees for POE10). For example, maximum demand recorded on a day with a recorded temperature of lower than 38 degrees will be adjusted up for POE50 purposes, depending on where on the curve the maximum demand day sits, relative to 38 degrees.

<u>Estimated Information:</u>

Weather corrected maximum demand is considered estimated data. This is considered to be management's best estimate based on the data available.

Table 3.4.3 System demand – 3.4.3.5 Power factor conversion between MVA and MW

- Average overall network power factor conversion between MVA and MW (DOPSD0301) was calculated as DOPSD0107 divided by DOPSD0207.

- Average power factor conversion for SWER lines (DOPSD0307) and Average power factor conversion for 22 kV lines (DOPSD0308) were estimated based on 2014 data from the SCADA system. Data for 2015 is not currently available at the level required to perform this calculation and there is no reason to suggest power factors would have changed significantly from 2014.

- Average power factor conversion for 6.6 kv lines (DOPSD0304) was calculated based on 2015 data from the SCADA system using the MW and MVAR flowing through the elements in the network that operate at 6.6kV.

- The 'Average power factor conversion for 66 kV lines' (DOPSD0311) was calculated as DOPSD0101 divided by DOPSD0201 as the energy flowing into the Zone Substations is assumed to be the same as flowing in the 66kV lines.

- Low voltage distribution lines have been estimated with reference to the Electricity Distribution Code and the calculated power factor for 22kV lines. AusNet Services low voltage customers are obliged to maintain their power factor as per the Distribution Code. This is stipulated in our connection agreements. The 22kV power factor reported in the RIN is 0.945, which is a reflection of the power factor maintained at low voltage. On this basis AusNet Services average long-term low voltage power factor can be assessed to be > 0.85 (lagging) or on average 0.90 (lagging). Therefore, 0.90 has been reported for this indicator.

- AusNet Services' 11kV feeders are dedicated to Latrobe Valley generation assets (eg mine supplies), as a result they do not supply other customers. The power factor of these few feeders has been assessed to be within 0.8 to 0.9, or on average 0.85.

Estimated Information:

Estimates were required in relation to power factors reported (variables DOPSD0307, DOPSD0308 and DOPSD0311) as system generated information is not available in the categorisation required. This is considered to be managements' best estimate based on the data available. Based on the RIN Instructions and Definitions, this information is permitted to be 'Estimated Information' on an ongoing basis where actual information is not available.

This is considered management's best estimate based on the data available.

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

Preparation Methodology:

Table 3.4.3.6 is not applicable to AusNet Electricity Services as all demand customers are billed on MVA not MW.

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

Preparation Methodology:

'Summated Chargeable Contracted Maximum Demand' (DOPSD0403) information was obtained from customer billing data.

'Summated Chargeable Measured Maximum Demand' (DOPSD0404) was obtained from customer billings.

3.5 Physical Assets

Table 3.5.1.1 Overhead network length of circuit at each voltage
Table 3.5.1.2 Underground network circuit length at each voltage

Network capacity variables are reported for the whole network including overhead power lines, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. Network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.

In relation to Table 3.5.1.1 'Overhead network length of circuit at each voltage' and Table 3.5.1.2 'Underground network circuit length at each voltage', circuit length is calculated from the length (measured in kilometers) of lines in service, where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.

<u>Preparation Methodology</u>:

For the 2015 Regulatory Year, a report was generated in the Asset Management System (SDME) which provided the voltage and length attributes required. The data was allocated into the specified categories taking into consideration the inclusions and exclusions discussed above. The report used was generated on 4 January 2016 to provide the circuit length as at 31 December 2015.

The information provided is considered 'actual information' as it was extracted from the SDME system, however it is noted that the system data has been subject to data cleansing and updating over the Regulatory Years.

Table 3.5.1.3 Estimated overhead network weighted average MVA capacity by voltage class
Table 3.5.1.4 Estimated underground network weighted average MVA capacity by voltage class

Weighted average capacities have been reported for both the overhead and underground network in the required voltage classes.

<u>Preparation Methodology</u>:

Data for the 2015 Regulatory Year was sourced from the Asset Management System (SDME) - including the conductor voltage ("Volts") and line length in kilometres ("length") for each section of line. The report extracted from SDME included details such as 'Specification' and 'Dictionary' name. These parameters were used to determine the associated amp rating. An internal document is maintained defining all Dictionary names.

Actual amp ratings were used which are considered to be reflective of operational ratings. The rating used to calculate the circuit capacity are the ratings of the particular conductor type at its design temperature (50 degC, 60 degC and etc), i.e. these are not adjusted for restrictions or limitations imposed on the capacity of the conductor due to its location in the network. Further, the amp ratings are not adjusted for lines which are constrained by voltage as voltage only constrains a small number of lines and changing the methodology to incorporate these voltage constrained lines is not expected to materially change the weighted average MVA capacity by voltage class.

Where the data extracted from SMDE didn't provide sufficient information to determine the amp ratings, additional information was sourced from a Feeder Ratings Database maintained by the Regional Network Planners. This Database includes information for the North, East and South regions. Inputs to the Database are based on historic internal information and also iinternal policy document AMS 20-24 'Sub-transmission line and Station Data for Planning Purposes'.

The weighted average was calculated based on the following methodology:

$$\frac{\text{Line 1: (length * Volts * Amps) + Line 2: (length * Volts * Amps) + Line 3: (length * Volts * Amps) etc.}}{\text{(Line 1 length + Line 2 length + Line 3 length etc.)}}$$

For three phase lines each group in the numerator has also been multiplied by $\sqrt{3}$.

The information provided is considered 'actual information' as it was extracted from the SDME system and sourced from supporting AusNet documentation, however it is noted that the system data has been subject to data cleansing and updating over the Regulatory Years.

Table 3.5.2 Transformer Capacities Variables

Table 3.5.2.1 Distribution transformer total installed capacity

A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.

The total installed Distribution Transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132kV, 66kV, 22kV or 11kV) distribution level. The capacity measure is the normal nameplate continuous capacity/rating (including forced cooling and other factors used to improve capacity).

Distribution Transformer capacity involved in the final level of transformation owned by AusNet Electricity Services and owned by High Voltage Customers has been reported.

Cold spare capacity is the capacity of spare transformers owned by AusNet Electricity Services but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.

Preparation Methodology:

Information in relation to 'Distribution Transformer capacity owned by AusNet Services' was sourced directly from the SDME Asset Management System - including the kVA capacity rating, and substation type.

'Distribution Transformer capacity owned by High Voltage customers' was estimated based on Capacity charges that are made to customer accounts using data obtained from the Annual AER Tariff Submissions. The data is based on the capacity charged to customers originally sourced from the billing system.

The data is based on what is charged to the customer at a peak rate and assumes this calculation as a maximum capacity. This is not what the customer has installed and will underestimate the actual installed rated capacity.

'Cold Spare Capacity' (DPA0503) for 2015 was sourced from a "stock on hand" report generated in SAP. The report used was generated on 1 January 2016 to provide the Cold Spare Capacity as at 31 December 2015.

Estimated Information:

Information provided in relation to 'Distribution Transformer capacity owned by High Voltage customers' is considered estimated information due to the preparation methodology outlined above. This is considered to be management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this metric is permitted to be "Estimated Information" on an ongoing basis.

All other information provided in Table 3.5.2.1 was sourced directly from SDME or SAP and is considered actual information.

Table 3.5.2.2 Zone substation transformer capacity

'Total installed capacity for first step transformation where there are two steps to reach distribution voltage' (DPA0601) and 'Total installed capacity for second step transformation where there are two steps to reach distribution voltage' (DPA0602) has been reported as zero value on the basis that AusNet Electricity Services does not have installed capacity with more than one step or transformation.

'Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage' (DPA0603) has been reported where there is only a single step of transformation.

'Cold Spare Capacity of zone substation transformers included in DPA0604' (DPA0605) has reported total Cold Spare Capacity included in total zone substation transformer capacity.

'Total zone substation transformer capacity' (DPA0604) was calculated as the sum of variables DPA0601, DPA0602, DPA0603 and DPA0605.

Preparation Methodology:

Table 3.5.2.2 was prepared on an asset by asset basis using information sourced from internal policy AMS 20-101 which is used for the Distribution Annual Planning Report. The ratings assumed were based on the nameplate capacity of the transformer unit.

Included in DPA0605 ‘Cold spare capacity of zone substation transformers included in DPA0604’ is 45MVA relating to cold spare capacity that can only be utilised at Yallourn Power Station.

Table 3.5.2.3 Distribution - other transformer capacity

Preparation Methodology:

Table 3.5.2.3 was prepared on an asset by asset basis using information sourced from internal policy AMS 20-101 which is used for the Distribution Annual Planning Report. The ratings assumed were based on the nameplate capacity of the transformer unit.

Table 3.5.3 Public lighting

Public lighting luminaires and Public lighting poles reported include both assets owned and assets operated and maintained (but not owned). Only poles that are exclusively used for public lighting have been included.

Preparation Methodology:

A report generated in the SDME Asset Management System was used to provide the data required for Public lighting luminaires (DPA0701) for the 2015 Regulatory Year. The report generated was reviewed by a subject matter expert and data records were corrected within the system where needed based on this review. The information provided is considered ‘actual information’ as it was extracted from the system and the presentation is not contingent on judgments and assumptions for which there are valid alternatives.

In relation to the number of Public lighting poles (DPA0702), data was extracted directly from the SDME Asset Management System. The information provided is considered ‘actual information’ as it was extracted from the system.

3.6 Quality of Service

Table 3.6.1 Reliability

An 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 premise. The customer interruption starts when it is 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. It does not include subsequent interruptions caused by network switching during fault finding. An interruption ends when supply is again generally available to the customer.

In this section reliability information is reported for unplanned interruptions, which is an interruption due to an unplanned event. An unplanned event is considered an event that causes an interruption where the customer has not been given the required notice for the interruption or where the customer has not requested the outage.

System Average Interruption Duration Index ("SAIDI") is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the average number of Distribution Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less).

System Average Interruption Frequency Index ("SAIFI") is the total number of unplanned sustained Customer interruptions divided by the average number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).

Whole of network SAIDI and SAIFI is the system wide SAIDI and SAIFI.

Section 3.3(a) of the Electricity Distribution Network Service Providers – STPIS Nov 2009 Amendment outlines the exemption criteria applicable in the EDPR period 2011-2015. Events that fall in any of the following conditions may be excluded in calculating the revenue increment or decrement as well as annual performance under the STPIS scheme.

1. [Deleted]
2. load shedding due to a generation shortfall;
3. automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition;
4. load shedding at the direction of the Australian Energy Market Operator or a system operator;
5. load interruptions caused by a failure of the shared transmission network;
6. load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning; and
7. load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.

In calendar year 2015, two transmission incidents occurred that meet the exclusion criteria 3.3(a)(5). Also there were twelve supply interruptions that occurred during Total Fire Ban (TFB) days as a result of the mandatory suppression of reclose functions on protective devices in areas covered by a TFB declaration. These supply interruptions meet the exclusion criteria 3.3(a)(7).

Customer numbers were calculated as the average of the January 2015 and December 2015 customer count.

The definitions and data used are consistent both with the AER's Distribution STPIS Guidelines and the AER Final Decision for the 2011-15 Electricity Distribution Price Review.

Table 3.6.1.1 Inclusive of Major Event Days

Preparation Methodology:

Information was sourced from AER 2015 Annual Regulatory Non-Financial Information Templates RIN ("Annual RIN Report").

Whole of network unplanned SAIDI – 'Unplanned Minutes-Off-Supply' are obtained from the 2015 Annual RIN Report and divided by the average number of distribution customers connected to the network in calendar year 2015.

Whole of network unplanned SAIDI with excluded outages - the annual total 'Unplanned Minutes-Off-Supply' from network events that are illegible for exclusion according to Section 3.3 of the 2011-2015 EDPR STPIS were obtained from the PowerOn network outage historical data and divided by the average number of distribution customers connected to the network in calendar year 2015. The transmission-related minutes were subtracted from the 'Whole of network unplanned SAIDI' in Table 3.6.1.1.

Whole of network unplanned SAIFI – 'Unplanned Interruptions' was obtained from the 2015 Annual RIN Report and divided by the average number of distribution customers connected to the network in calendar year 2015.

Whole of network unplanned SAIFI with excluded outages - the annual total 'Unplanned Interruptions' from network events that are illegible for exclusion according to Section 3.3 of the 2011-2015 EDPR STPIS was obtained from the PowerOn system network outage historical data and divided by the average number of distribution customers connected to the network in calendar year 2015. The transmission-related interruptions were subtracted from the 'Whole of network unplanned SAIFI' in Table 3.6.1.1.

Estimated Information:

No estimates were required.

Table 3.6.1.2 Exclusive of Major Event Days

Preparation Methodology:

Historical outage data from the Poweron System was used to calculate the daily unplanned SAIDI and SAIFI in 2015.

The Major Event Days ("MED") threshold was calculated for the 2015 Regulatory Year from the daily Unplanned SAIDI data between Regulatory Years 2010 and 2014 (5 years) using the annual AER RIN Template MED calculator.

In relation to 'Whole of network unplanned SAIDI' and 'Whole of network unplanned SAIFI' - the summed unplanned SAIDI for all MED was subtracted from the Total SAIDI value in Table 3.6.1.1 (DQS0101) to obtain the SAIDI performance exclusive of the MED impact. The same process was followed for unplanned SAIFI.

'Whole of network unplanned SAIDI with excluded outages': the 'Whole of network unplanned SAIDI' in Table 3.6.1.2 and the 'Whole of network unplanned SAIDI excluding excluded outages' in Table 3.6.1.1 (DQS0102) was subtracted from the 'Whole of network unplanned SAIDI' in Table 3.6.1.1. The same process was followed for 'Whole of network unplanned SAIFI with excluded outages'.

Estimated Information:

No estimates were required.

Table 3.6.2 Energy not supplied

Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions and is reported exclusive of the effect of Excluded Outages.

Preparation Methodology:

The reported values of energy not supplied were obtained from the 2015 Annual RIN Report.

An estimate was performed of the raw (not normalised) energy not supplied due to unplanned customer interruptions. The estimate was calculated based on average customer demand multiplied by the number of customers interrupted and the duration of the interruption. Average customer demand was determined from average consumption of customers on the feeder based on their billing history.

Data reported for DQS0102 has been reported exclusive of the effect of Excluded Outages.

Estimated Information:

Estimates provided for Energy not supplied (both unplanned and unplanned) are considered to be management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this information is permitted to be "Estimated Information" on an ongoing basis.

Table 3.6.3 System losses

System losses are the proportion of energy that is lost in the distribution of electricity from the transmission network to customers. It has been calculated as the difference between electricity imported and electricity delivered as a percentage of electricity imported.

Electricity imported is the total electricity inflow into the distribution network (including from Embedded Generation) less the total electricity outflow into the networks of the adjacent connected distribution network service providers or the transmission network.

Electricity delivered is the amount of electricity transported out of the network to customers as metered (or otherwise calculated) at the customer's connection. This is a system wide figure not a feeder level figure.

<u>Preparation Methodology</u>:

System losses are calculated as the sum of

> DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories' - DOPED01 'Total energy delivered') +
>
> (DOPED0404 'Energy received from embedded generation not included in above categories from non-residential embedded generation' +
>
> DOPED0408 'Energy received from embedded generation not included in above categories from residential embedded generation' –
>
> DOPED01 'Total Energy Delivered'
>
> divided by
>
> (DOPED0404 'Energy received from embedded generation not included in above categories from non-residential embedded generation' +
>
> DOPED0408 'Energy received from embedded generation not included in above categories from residential embedded generation' +
>
> DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories').

<u>Estimated Information</u>:

No estimates were required.

Table 3.6.4 Capacity utilisation

Capacity utilisation is a measure of the capacity of zone substation transformers that is utilised in the 2015 Regulatory Year. The sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity is reported.

Thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant) being the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity is the continuous rating.

<u>Preparation Methodology</u>:

Data was calculated as variable DOPSD0201 Non–coincident Summated Raw System Annual Maximum Demand divided by variable DPA0604 Total zone substation transformer capacity.

<u>Estimated Information</u>:

No estimates were required.

3.7 Operating environment

Table 3.7.1 Density factors

'Customer Density' (DOEF0101) is the total number of customers divided by the route line length of the network.

'Energy Density' (DOEF0102) is the total MWh divided by the total number of customers of the network.

'Demand Density' (DOEF0103) is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network.

Preparation Methodology:

'Customer Density' (DOEF0101) was calculated as 'Total Customer Numbers' (DOPCN01) divided by 'Route Line Length' (DOEF0301). In the 2015 Regulatory Year, Route Line Length includes both Overhead Route Line Length and Underground Route Line Length. In previous Regulatory Years, this metric only included Overhead Route Line Length.

'Energy Density' (DOEF0102) was calculated as the 'Total Energy Delivered' in GWh (DOPED01) x 1000 divided by 'Total Customer Numbers' (DOPCN01).

'Demand Density' (DOEF0103) was calculated as DOPSD0201 'Non–coincident Summated Raw System Annual Maximum Demand' x 1000 divided by 'Total Customer Numbers' (DOPCN01).

Estimated Information:

'Customer Density' (DOEF0101) information is considered estimated information as the 'Route Line Length' (DOEF0301) variable included in the calculation of customer density was estimated.

This is considered to be management's best estimate based on the data available.

Table 3.7.2 Terrain factors

A. Rural proportion (DOEF0201)*:*

Rural proportion is the distribution route length classified as short rural or long rural in kilometers ("km") divided by the total network line length.

Preparation Methodology:

Using the line length data reported in Annual Feeder Reliability Data (*RIN 4a. Network perf - Feeders*), the proportion of high voltage line lengths connected to rural (i.e. short, long) feeders to the total line length of the distribution network was calculated considering both overhead and underground lines. It excludes sub-transmission (i.e. 66kV) and low voltage networks.

Estimated Information:

As the current system does not distinguish between rural and urban route line length, feeder data has been used as a proxy to calculate the required information. This is considered to be management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this information is allowed to be 'Estimated Information' on an ongoing basis where actual information is not available.

B. Urban and CBD vegetation maintenance spans (DOEF0202), Rural vegetation maintenance spans (DOEF0203), Total vegetation maintenance spans (DOEF0204) and Total number of spans (DOEF0205)

Maintenance span is the network span that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include inspection of vegetation maintenance spans - where 'inspection' is only for the purpose of identifying trees or other vegetation that require trimming or removal and includes vegetation scoping works.

Urban and CBD maintenance spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant Regulatory Year. CBD and urban areas are consistent with CBD and urban customer classifications.

Rural maintenance spans refer to spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders.

Urban and Rural maintenance spans were determined using information extracted from the Vegetation Management system which was split into area category (Urban and Rural) using feeder data and further disaggregated into maintenance spans and spans clear of vegetation. 'Urban and CBD vegetation maintenance spans' (DOEF0202) and 'Rural vegetation maintenance spans' (DOEF0203) were determined as PT1 to PT365 per the system data (which denotes spans where vegetation maintenance is required in the next 365 days). DOEF0202 and DOEF0203 include only spans subject to action/cutting rather than inspection or assessment only.

'Total Vegetation Maintenance spans' (DOEF0204) was calculated as the sum of 'Urban and CBD vegetation maintenance spans' (DOEF0202) and 'Rural vegetation maintenance spans' (DOEF0203).

The information for (DOEF0202), (DOEF0203) and (DOEF0204) was extracted from the Vegetation Management system. The data reported excludes 66kV sub-transmission lines as the feeder classifications (i.e. Urban, Short Rural, Long Rural) do not apply. Urban, Short Rural and Long Rural classifications are only applicable to feeders with voltage levels between 6.6kV and 22kV which a distributor uses to distribute electricity (per the Electricity Distribution Code). Therefore these classifications cannot be applied to sub-transmission feeders (ie 66kV) and higher voltage levels. The omission of these lines represents a percentage of < 1% of total spans which AusNet Services considers immaterial.

'Total number of spans' (DOEF0205) is the total count of spans in the network in the relevant Regulatory Year. This information was extracted from the Vegetation Management system.

Estimated Information:

No estimates were required.

C. Average urban and CBD vegetation maintenance span cycle (DOEF0206) and Average rural vegetation maintenance span cycle (DOEF0207)

Maintenance span cycle refers to the planned number of years between which cyclic vegetation maintenance is performed for the relevant area. Information in relation to the average vegetation maintenance span cycles was obtained from the Vegetation Management system and also per the vegetation management plan.

Estimated Information:

No estimates were required.

D. Average number of trees per urban and CBD vegetation maintenance span (DOEF0208) and Average number of trees per rural vegetation maintenance span (DOEF0209)

The 'Average number of trees per maintenance span' includes only trees that require active vegetation management to meet vegetation management obligations. It excludes trees that only require inspections and no other vegetation management activities are needed to comply with AusNet Electricity Services' vegetation management obligations.

Vegetation Management field staff record the number of trees actioned (PT1, PT30, PT180, PT365) in each span, into the VMS. Systems analysts run a query to quantify the average numbers of actioned trees per maintenance span across the Urban and CBD and Rural areas.

Estimated Information:

No estimates were required.

E. Average number of defects per urban and CBD vegetation maintenance span (DOEF0210) and Average number of defects per rural vegetation maintenance span (DOEF0211)

Defects are any recorded incidence of non-compliance with a NSP's vegetation clearance standard and include vegetation outside the standard clearance zone that is recognised as hazardous vegetation and would normally be reported as requiring management under inspection practices. Defects on a vegetation span are recorded as one, regardless of the number of defects on the span.

Information to calculate average number of defects per urban and CBD vegetation maintenance span was extracted from the Vegetation Management system and Hazard Tree Database and excludes 66kv Sub-Transmission lines for Urban and Rural feeders as AusNet Services cannot provide the classification for these lines. The omission of these lines represents a percentage of < 1% of total spans, which AusNet Services considers immaterial. The total number of defects was calculated as the number of PT1 and PT30 spans which are vegetation spans requiring action in the next 30 days, and any rating 1,2,3,4&5 Hazard Tree (meaning Trees which required action due to defects). To calculate the average number of defects, the total number of defects was divided by the number of vegetation maintenance spans requiring action/cutting. This calculation was performed for both urban and CBD and Rural spans.

Estimated Information:

No estimates were required.

F. Tropical Spans (DOEF0212)

Tropical spans are the approximate total number of urban and rural Maintenance Spans in the Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity). There are no Tropical Spans in AusNet Electricity Services' urban and rural Maintenance Spans.

Estimated Information:

No estimates were required.

G. Standard Vehicle Access (DOEF0213)

Standard vehicle access refers to areas which are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks). Areas not accessible by a standard vehicle have been reported.

A calculation was performed of spans which needed a climbing party to enable access (during the 2015 Regulatory Year) divided by the total number of spans on the network. This data was obtained from the Vegetation Management System. The 2015 overhead route line length in kilometers was multiplied by the percentage calculated above. This provides an estimate of the area in kilometers which is accessible by a standard vehicle.

The overhead route line length was extracted from the SDME Asset Management System. Underground route line length has been excluded from this calculation as it is not relevant to the measure of the proportion of network not accessible via a standard vehicle.

This calculation does not take into consideration that the use of a climber is not fully correlated with there being no standard vehicle access – for example, a climber may have been used due to uneven terrain (but some of the surrounding area may have been accessible by a standard vehicle), wet weather may have forced climber use, etc. This estimation also assumes that the length of each span is consistent and there have been no changes in route line length. However, areas which require a climber for access is considered management's best estimate based on the data available.

Estimated Information:

The required information is not captured in the Vegetation Management System; therefore, an estimate is required.

This is considered to be Managements best estimates based on the data available.

H. Bushfire Risk (DOEF0214)

Bushfire risk is the number of Maintenance Spans in high bushfire risk areas.

High bushfire risk maintenance spans include feeders with high voltage levels which are not included in DOEF0203. This is because the Bushfire Risk variable does not need to be distinguished into Urban and Rural. This data is captured within the Vegetation Management System and is based on information provided from the Country Fire Authority.

Estimated Information:

No estimates were required.

Table 3.7.3 Service area factors

The Route Line Length is the aggregated length in kilometers of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.

Preparation Methodology:

The route line lengths for overhead and underground were summed to calculate the total route line length.

Overhead Route Line Length:

For the 2015 Regulatory Year, overhead line length data was extracted from the SDME Asset Management System. In SDME, high voltage (HV) and low voltage (LV) overhead conductors are connected to poles (or nodes) which allow the calculation of span line lengths with single or multiple circuits. A report was generated from the SDME Asset Management System which provided the information required for Overhead Route Line Length.

Underground Route Line Length:

Underground conductor circuit line lengths are available in SDME. However since underground construction do not have poles (or nodes) for span line length calculation the HV and LV Underground Route Line Lengths were estimated. The following process was followed:

- A report was generated from the SDME Asset Management System which provided the underground circuit length by feeder – split between urban, short rural and long rural.
- Sample feeders were selected in each of the urban, short rural and long rural feeder classifications. A total of nineteen feeders were investigated representing 5.5% of total distribution feeders.
- For each feeder in the sample, geographic routes were investigated by a subject matter expert and the underground route line length was calculated.

- For each feeder in the sample, the ratio of calculated route line length to circuit length was determined (the “factor”) and a weighted average factor was calculated for the urban, short rural and long rural feeder classifications.

The weighted average factors and calculation performed is as per below:

Urban feeder	= 92.8% x total urban underground circuit length
Rural short feeder	= 96.9% x total rural short underground circuit length
Rural long feeder	= 98.9% x total rural long underground circuit length

- LV underground route length:
  - Factors above for urban, short rural and long rural feeders were applied to the LV circuit lengths from SDME to estimate the LV underground route line length.
- HV underground route length:
  - It is estimated (via desktop survey in SDME) that 95% of HV underground cable installations also have LV underground cables in the same trench or easement. For this reason the HV underground route line length is calculated by multiplying 5% to the HV underground circuit length for both urban and rural feeders.

<u>Estimated Information</u>:

The data provided is estimated information due to the preparation approach outlined above. This is considered to be management’s best estimate based on the data available.