Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2014 regulatory year

Basis of preparation for the 2014 regulatory year

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GLOSSARY

ACS	Alternative Control Service
AER	Australian Energy Regulator
BOM	Bureau of Meteorology
CAM	Cost Allocation Method
CFA	Country Fire Authority
CIS	Customer Information System
CMOS	Customer Minutes Off Supply
CPI	Consumer Price Index
CY	Calendar Year
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Providers
DRC	Depreciated Replacement Cost
DUoS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
EBT	Economic benchmarking asset categories
EDPR	Electricity Distribution Price Review
ERP	Enterprise Resource Planning
ESC	Essential Services Commission
FQ	Fee and quote based services
FY	Financial Year
GIS	Geospatial Information System
GL	General Ledger
HV	High Voltage
IMS	Interval Meter Store
JAM	Jemena Asset Management Pty Ltd
JAM6	Jemena Asset Management 6 Pty Ltd
JEN	Jemena Electricity Networks (Vic) Limited
KPI	Key Performance Indicators
LV	Low Voltage
MD	Maximum Demand
MED	Major Event Day
MVA	Megavolt Amperes
MVAr	Megavolt Ampere Reactive
MW	Mega Watts

NEL	National Electricity Law
NMI	National Meter Identifiers
NPV	Net Present Value
NS	Network Services
OH	Overhead
OMS	Outage Management System
ORG	Office of the Regulator General
P&L	Profit and Loss
PF	Power Factor
RAB	Regulated Asset Base
RAS	Regulatory Accounting Statements
RFM	Roll-forward model
RIN	Regulatory Information Notice
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
TT	Thomastown Terminal
UG	Underground
VMS	Vegetation Management System
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Structure

1. BUSINESS & OTHER DETAILS

1. Jemena Electricity Networks (Vic) Ltd (**JEN**) is required to respond to an economic benchmarking Regulatory Information Notice (**RIN**), with information relating to calendar year 2014. RIN data templates and a statutory declaration providing assurance for all data and accompanying documents is due by 30 Apr 15. The RIN was served upon JEN by the AER under the National Electricity Law (**NEL**) on 28 November 2013.

2. Section 2.2 of Schedule 2 of the RIN requires JEN to prepare a 'basis of preparation' in accordance with the requirements specified in Schedule 1. This document—JEN's basis of preparation (for each variable and any other information):

    1. demonstrates how the information provided is consistent with the requirements of the RIN;
    2. explains the source from which JEN obtained the information provided;
    3. explains the methodology JEN applied to provide the required information, including the assumptions (if any) JEN made;
    4. explains, in circumstances where JEN cannot provide input for a variable using actual information and therefore must provide input using estimated information:
        a) why an estimate is required, including why it is not possible for JEN to use actual financial Information or actual non-financial information (as the case may be, depending on the variable);
        b) the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is JEN's best estimate, given the information sought in the RIN.

3. The RIN requires that the basis of preparation—for every variable in the Excel templates—explains the basis upon which JEN prepared information to populate the input cells. JEN notes that the AER intends to publish JEN's basis of preparation along with the RIN Excel templates.

4. JEN considers this basis of preparation complies with the AER requirement that the basis of preparation must follow a logical structure that enables auditors, assurance practitioners and the AER to clearly understand how JEN has complied with the requirements of the RIN. JEN has structured this basis of preparation to align with sections of the same numerical template reference in the Excel templates (i.e. section 2. Revenue of this basis of preparation document refers to Excel template 2. Revenue).

5. JEN has included in its basis of preparation, all other information JEN prepared in accordance with the requirements of the RIN. For example, where JEN chose to disaggregate its Regulated Asset Base (**RAB**) using its own approach in addition to the AER's standard approach, JEN has explained its approach in detail in its basis of preparation. The procedure documents and supporting models attached to last years' (CY2013) RIN response still stand as explanation to how we disaggregated the RAB.

6. The actual financial information has been reconciled to the current year regulatory accounting statements, and the principles underpinning the figures in Revenue and Opex are in line with JEN's statutory accounting policies. There are no material departures from the recognition and measurement aspects of JEN's statutory accounting policies, for the purposes of regulatory reporting, with the exception of customer contributions, which are captured and included within property, plant and equipment in the statutory accounts, but are excluded from the RAB disclosure of regulatory accounts.

PROCESS REQUIREMENTS

7. JEN's basis of preparation will be audited or reviewed and verified by statutory declaration by 30 April 2015, as part of the audit or review of the Economic Benchmarking Data Templates. The auditor will ***review*** JEN's basis of preparation when conducting their audit of actual information and issuing their review conclusion on the estimated information.

BEST ESTIMATES

8. Where JEN cannot populate an input cell in the Excel templates with actual information, it has provided its best estimate, considering data availability constraints, JEN's limited knowledge of how the information may be applied or interpreted and JEN being unaware of a superior estimation technique at the time. As such, JEN cautions the AER from using this data to inform regulatory decisions without first confirming with JEN its understanding of the methodologies used, availability of data and any other limitations that may exist.

9. Where JEN provides an estimate, it has, in its basis of preparation, explained:

    1. why it could not use actual information

    2. the basis upon which the estimate was made including detail of the methodology applied, and

    3. why it is JEN's best estimate.

DEFINITIONS OF ACTUAL INFORMATION

10. JEN has adopted the AER's definition of 'actual information' in its response to the RIN. The RIN and explanatory statement define actual information as:

> *"Information presented in response to the Notice whose presentation is Materially dependent on information recorded in JEN's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.*
>
> *"Accounting records" include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate JEN's regulatory accounts and responses to the Notice.*
>
> *'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on."*

BLACKED OUT CELLS

For each variable which the RIN and the Excel templates (through orange or blue shading) identify as potentially not applicable to JEN, JEN has considered whether the variable is actually applicable to it.

11. Where the variable is actually applicable to JEN, JEN has completed the variable in accordance with the RIN and its explanatory statement.

HOW JEN'S RESPONSE TO EACH VARIABLE MEETS THE REQUIREMENTS OF THE RIN

JEN considers that all information provided in this response, for each variable and any other information, is consistent with the requirements of the RIN. This is evident in that:

- JEN has provided complete Microsoft Excel workbooks attached at Appendix A of the RIN that accord to the RIN and the instructions and definitions in Appendix B of the RIN
- JEN has provided a basis of preparation that demonstrates JEN's compliance with each of the information requirements. JEN's basis of preparation, for each variable and any other information:
  - Explains the source from which JEN obtained the information provided
  - Explains the methodology JEN applied to provide the required information, including any assumptions made
  - Where JEN has estimated information, its basis of preparation explains why an estimate was required, including why it was not possible for JEN to use actual information, explains the basis of the estimate, including the approach used, assumptions made and why JEN considers the estimate to be JEN's best estimate
- JEN has provided supporting information or documentation used to comply with the requirements of the RIN
- JEN will provide the audit and review reports in accordance with the requirements of the RIN by 30 April 2015.

3. ECONOMIC BENCHMARKING

3.1 REVENUE

3.1.3 REVENUE GROUPING BY A CHARGEABLE QUANTITY

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DREV0101 – DREV0109	The data is sourced from JEN's two billing systems. The data is then captured in the Excel Line Charge file LC2014.xls on a monthly basis and is summated in worksheet "Year to date". The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet "Year to date".	**DREV0101 TO DREV0109** is categorised as Standard Control Services. Data provided relates to DUoS revenue + F-factor. This is in line with section 3.2 of the Explanatory Statement - Economic Benchmarking RIN that requires revenues to be reported inclusive of the effect of incentive schemes. The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DREV0101**: Comprises of Standing charge revenue for all tariff codes. **DREV0102:** Comprises of Peak revenue for A100 and A200 tariff codes. **DREV0103:** Comprises of Peak revenue except for A100, A200 and A290 tariff codes. **DREV0104**: Comprises of Shoulder revenue for all tariff codes **DREV0105**: Comprises of All Off-Peak revenue except for A180 and A290 tariff codes.

Variable	Source and why actual	Methodology	Assumptions
			DREV0106: Comprises of Peak and Off Peak revenue for A180 tariff code. **DREV0107**: Comprises of Peak and Off Peak revenue for A290 tariff code. **DREV0108:** Demand charge captured under variable code DREV0109. **DREV0109:** Comprises of Billed Maximum demand revenue for all tariff codes.
DREV0110	Prescribed metering is defined as a metering charge pre 2010. Therefore, no prescribed metering charges reported for 2014. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	n/a	n/a
DREV0111	The data is sourced from JEN's annual RIN tab 14 "Alternative Control Services and Other Services" The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect	Data obtained from JEN's annual RIN tab 14. This information is initially extracted from the GL. Only product codes relating to Routine New connections are summated. **DREV0111** is categorised as Alternative control Services.	Routine connections are the sum of the Routine connections - customers below 100 amps and Routine connections, for customers > 100amps.

Variable	Source and why actual	Methodology	Assumptions
	information for Economic Benchmarking November 2013.		
DREV0112	The data is sourced from JEN's annual RIN tab 14 "Alternative Control Services and Other Services". The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	Data obtained from JEN's annual RIN tab 14. This data was originally extracted from the GL accounts which were initially extracted from JEN's billing systems. Only product codes relating to Alternative Control Services Public Lighting are summated.	**DREV0112** is categorised as Alternative Control services.
DREV0113	The data is sourced from JEN's annual RIN tab 14 "Alternative Control Services and Other Services". The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	Data obtained from JEN's annual RIN tab 14. This information is initially extracted from the GL. Only product codes relating to Routine New connections are summated. The total of the fee based and quoted based charges are summated, once summated the routine new connections charge (DREV0111) is subtracted for each calendar year to derive DREV0113.	**DREV0113** is categorised as Alternative Control services.

Estimated Information

12. No estimated information is provided.

3.1.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DREV0201 – DREV0206	The data is sourced from JEN's two billing systems. The data is then captured in the Excel Line Charge file LC2014.xls on a monthly basis and is summated in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date.	**DREV0201 TO DREV0206** is categorised as Standard Control Services, only relates to DUoS revenue. The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DREV0201:** Comprises of DUoS revenue for A100 to A180 tariff codes. **DREV0202:** Comprises of DUoS revenue for A200, A210 and A250 tariff codes. **DREV0203:** Comprises of DUoS revenue for A230, A250, and A300 to A37R tariff codes. **DREV0204:** Comprises of DUoS revenue for A400 to A50E tariff codes. **DREV0205:** Comprises of DUoS revenue for A290 tariff code.

Variable	Source and why actual	Methodology	Assumptions
DREV0206 Alternative Control Service	The data is sourced from JEN's annual RIN tab 14 "Alternative Control Services and Other Services". The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	Summation of DREV0111, DREV0112 & DREV0113 The data is classified as "revenue from other customers" as there is no report to capture this information by customer type or class.	n/a

Estimated Information

13. No estimated information is provided.

3.1.3 REVENUE (PENALTIES) ALLOWED (DEDUCTED) THROUGH INCENTIVE SCHEMES

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DREV0303	This is the AER approved F-factor amount as per the pricing submission. The number is sourced from the Attachment 1 - JEN 2014 Tariff Approval Model.xls of the AER model.	n/a	The amount provided is the F-factor amount that JEN was allowed to collect (as per the submission to the AER) not the amount that JEN has actually collected as per the GL account.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DREV0301	This variable is an estimate as the EBSS forms part of the building block revenue determined at the beginning of each regulatory period.	Step 1: Replicate the ESC and AER's calculations to calculate the NPV of the building block revenues and the smoothed revenues using a nominal WACC for the period 2011-15. Step 2: Calculate the relative share of the building block components that contribute to the NPV calculations. Step 3: Re-state the building block and smoothed revenues to nominal dollars using actual CPI instead of the AER CPI forecast. Step 4: Notionally break down the smoothed revenue into building block components (using the relative share calculated in step 2). Step 5: Apply the EBSS relative share from the building block for the Regulatory period 2011-2015 to the actual revenue earned for each calendar year. Where; actual revenue earned = actual revenue reported net of any incentive mechanism schemes, and	Actual CPI for 2014is the weighted average for the eight capital cities for the September quarter of 2014. L factor treated as part of actual revenue earned as it is insignificant at $18k p.a.	This is considered JEN's best estimate as the methodology applies a relative share as determined from the building block revenue for each regulatory period. The relative share associated with EBSS is then applied to the actual revenue earned net of any incentive mechanisms.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DREV0302	STPIS component is an estimate, as it forms part of the DUoS tariff: DUoS price path is (1+CPI)*(1-X)*(1+S")*(1+L).	EBSS relative share is an average for each regulatory period. S factor = actual revenue earned – actual revenue earned/ **(1+ S")** Where; actual revenue earned = actual revenue reported net of F-factor incentive mechanism schemes	Actual CPI for 2014is the weighted average for the eight capital cities for the September quarter of 2014. L factor treated as part of actual revenue earned, as it is immaterial at $18k p.a.	This is considered JEN's best estimate as the methodology applies a relative share as determined from the building block revenue for each regulatory period. The relative share associated with S factor true-up is then applied to the actual revenue earned net of any incentive mechanisms.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DREV0304	This variable is an estimate as the S factor true-up forms part of the building block revenue determined at the beginning of each regulatory period.	Step 1: Replicate the ESC and AER's calculations to calculate the NPV of the building block revenues and the smoothed revenues using a nominal WACC for the period 2011-15. Step 2: Calculate the relative share of the building block components that contribute to the NPV calculations. Step 3: Re-state the building block and smoothed revenues to nominal dollars using actual CPI instead of the AER CPI forecast. Step 4: Notionally break down the smoothed revenue into building block components (using the relative share calculated in step 2). Step 5: Apply the S factor true up relative share from the building block for the Regulatory period 2011-2015 to the actual revenue earned for each calendar year. Where: S true factor relative share is an average for the regulatory period		

3.2 OPERATING EXPENDITURE

3.2.1 OPEX CATEGORIES

3.2.1.1 Current Opex categories and cost allocations

Actual Information

Variable	Source and why actual	Methodology	Assumptions
SCS DOPEX0102 (Condition) DOPEX0104 (Emergency)	Data (Maintenance and opex) is extracted from Appendix B of JEN's CY 2014 Annual RIN responses. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	Maintenance items disclosed in Appendix B of the annual RIN are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity. (e.g. Faults, Emergencies, Standards and Procedures, etc.). Note that the SAP network codes are also designed to identify the regulatory service categories. (I.e. SCS, Public Lighting, ACS, etc.). JEN uses time writing to capture internal labour costs. Where practical and appropriate all employees time write to an activity/network	The Activities/networks in SAP are not setup to aggregate to regulatory categories. Hence, an experienced Senior Engineer using professional judgement provides advice on how the activities should be allocated. (Based on a percentage of total cost of each activity) into these categories (routine, condition based and emergency). This allocation methodology is also applied in JEN's annual RIN response for CY14.

Variable	Source and why actual	Methodology	Assumptions
		or to a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved Cost Allocation Method (**CAM**).	
SCS DOPEX0101 (Routine) DOPEX0103 (Vegetation control) DOPEX0105 (Inspection)	Data is sourced directly from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and other information.	JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/ networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity. (e.g. Faults, Emergencies, Standards and Procedures, etc.). Note that the SAP network codes are also designed to identify the regulatory service categories. (i.e. SCS, Public Lighting, ACS, etc.). JEN uses time writing to capture internal labour costs. Where practical and appropriate all employees time write to an activity/network or to a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved Cost Allocation Method (CAM). For CY14 JEN's Annual RIN response discloses the Total Routine expenditure, therefore data for the purposes of RIN B (CY14) is disclosed by first isolating the	The Activities/networks in SAP are not setup to aggregate to regulatory categories. Hence, an experienced Senior Engineer using professional judgement provides advice on how the activities should be allocated. (Based on a percentage of total cost of each activity) into these categories (routine, condition based and emergency). This allocation methodology is also applied in JEN's annual RIN response for CY14.

Variable	Source and why actual	Methodology	Assumptions
		Vegetation and Inspection expenditure within the Total Routine expenditure for CY14 and then reporting the remaining costs as Routine expenditure within (DOPEX0101).	
SCS DOPEX0106 (SCADA)	Appendix B of the JEN's Annual RIN response for CY 2014. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The information is sourced directly from SAP which delivers a report for this activity. This activity is mapped to the specific regulatory category. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved CAM.	n/a
SCS DOPEX0107 (Other - Standard Control Services (a))	Appendix B of the JEN's Annual RIN response for CY 2014. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	Information is sourced from JEN's related parties. (Jemena Asset Management Pty Ltd (**JAM**) and Jemena Ltd (**JEM**). CY14 data is based on data collected by the Work Breakdown Structure (**WBS**) codes.	n/a
ACS DOPEX0109 (Public Lighting)	Appendix B of the JEN's Annual RIN response for CY 2014. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	SAP network codes are also designed to identify the regulatory service category (i.e. Standard Control Services (SCS), Public Lighting, ACS, etc.) The costs are collected into activities which align with the Alternative Control Service - Public Lighting regulatory category. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved CAM.	n/a

Variable	Source and why actual	Methodology	Assumptions
ACS DOPEX0110 (Alternative control – other Feeder)	JEN's Annual RIN response for CY 2014. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The methodology applied to derive reserve feeder costs is explained below. Activities were identified in JEN's operational works program which are related to the provision of operational and maintenance ('O&M') service for distributing electricity to customers. This included reserve feeder service customers. These activities were proportioned for high voltage distribution, which is where reserve feeder services are normally provided. The high voltage distribution proportion is then applied to the costs of the activities to derive the estimated cost of the O&M service for high voltage distribution. These costs were then divided by the system demand forecast (in kW) to derive the estimated $ cost per kW unit for the O&M service for high voltage distribution. This $/kW rate was then multiplied by the billed demand (in kW) associated with customers receiving a reserve feeder service.	n/a
SCS DO'PEX0113–DOPEX0125 except DOPEX0120 & DOPEX0121	JEN's Annual RIN response for CY 2014. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	"Activities" disclosed in Appendix B of JEN's annual RIN response are sourced from SAP the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and some operational information. JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level.	n/a

Variable	Source and why actual	Methodology	Assumptions
		These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. JEN uses time writing to capture internal labour costs. JEN has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These then form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of the RIN responses.	
SCS DOPEX0120 (licence fee)	Data specific to a GL account is sourced from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and other information.	The data is extracted from the relevant General Ledger account.	n/a
SCS DOPEX0121 (GSL Payment)	Data specific to a GL account is sourced from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and other information.	The data is extracted from the relevant General Ledger account.	n/a
ACS DOPEX0119 (Information Technology),	JEN's Annual RIN response for CY 2014.	The Activities disclosed in Appendix B of JEN's annual RIN response are sourced from SAP. ACS related activities are mapped to the appropriate service offered. Where practical	n/a

Variable	Source and why actual	Methodology	Assumptions
DOPEX0126 (Public Lighting) & DOPEX0127(Alternative control –other)		and appropriate, all employees time write to an activity/network or a client, these then form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM.	
DOPEX01A Table 3.2.1.2A - Historical opex categories and cost allocations (SCS & ACS)	JEN has no changes to historical opex categories and cost allocations.	n/a	n/a
DOPEX01B Table 3.2.1.2B - Historical opex categories and cost allocations (SCS & ACS)	JEN has no changes to historical opex categories and cost allocations.	n/a	n/a
DOPEX01C Table 3.2.1.2C - Historical opex categories and cost allocations (SCS & ACS)	JEN has no changes to historical opex categories and cost allocations.	n/a	n/a

3.2.2 OPEX CONSISTENCY

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOPEX0203A (Opex for connection services)	Data is sourced directly from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and other information, specific to set of activities, captured within projects. The data is considered actual as it is extracted from the relevant project (WBS) that is set up to capture costs relating to Faults & Emergencies for Premises activity.	From the total costs extracted, data pertaining to a specific contractor, together with costs relating to the internal crew is isolated and disclosed in the template.	n/a
DOPEX0204A (Public Lighting)	Sum of DOPEX0109 and DOPEX0126A	n/a	n/a

Estimated Information

Variable	Why estimate, not actual	Basis for estimate
DOPEX0201A Opex for network services	DOPEX0201A is a result of DOPEX01 less DOPEX0203A and DOPEX0206A.	The basis being, Opex for network services is estimated to be the residual amount after reducing the Total DOPEX01 (SCS) by DOPEX0203A (Opex for connection services) and DOPEX0206A (Opex for Transmission connection point planning).
DOPEX0206A (opex for transmission connection point planning)	This information is considered to be an estimate as it cannot be directly drawn from JEN's internal business records. Therefore JEN's engineers provided their best estimate of the proportion of costs from various activities which relate to this service.	The engineers provide their best estimate of the effort required (in terms of FTE's) per annum for this activity. This estimated effort is then multiplied by the average cost per annum, per engineer in nominal dollar value, to arrive at the total expense for the period. For 2014, the effort (in terms of FTEs) estimated for CY2013, was reviewed by the engineer and determined to be applicable and appropriate for CY 2014. The average cost per engineer, as used in CY2013 was reviewed and escalated by the applicable percentage to arrive at the total cost estimate for CY2014.
DOPEX0401 (high voltage customers)	This is an estimate as the costs are not incurred by JEN and are therefore not maintained within JEN's internal systems.	The engineering team provided an estimate of activities and their costs that may have been incurred over a block of 4 years. This cost is divided by 4 to arrive at an estimated cost per annum. For 2014, the costs estimated for CY2013, was reviewed by the engineer and escalated by the applicable percentage to arrive at the total cost estimate for CY2014. The number of High Voltage Customers was reviewed and updated by the engineer to reflect the right level applicable for CY2014. The number of High Voltage Customers for CY14 is then multiplied by the updated cost estimate for CY14, to then arrive at the total cost estimate for CY14.

3.2.3 PROVISIONS

Actual Information

Variable	Source and why actual	Methodology
All variables (DOPEX0301A – DOPEX0314A) Provision for doubtful debts	The data is considered actual as it is extracted from the relevant General Ledger from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and other information. The information obtained in the General Ledger is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	JEN provides for two provisions, i.e. Provision for Doubtful Debts and Provision for Claims/Compensation. When JEN incurs actual expenses in the form of Bad Debts by its customers, these are recognised in the Profit and Loss (P&L) statement. JEN adjusts these provisions in accordance with its internal policies to ensure that the provisions are recognised, measured and disclosed in the Special Purpose Financial Report (SPFR) in accordance with Australian Accounting Standards. The total of monthly routine accruals is disclosed under "Provisions made in the period, resulting in increases to the existing provisions". Similarly the total of monthly routine reversals is disclosed under "Unused amounts reversed during the period". Due to the nature of doubtful debt and claim provisions, expenses incurred are OPEX in nature. There is no impact to CAPEX, therefore no disclosure in the CAPEX subsections of Table 3.2.3 For CY2014 there is no provision balance being utilised, per relevant General Ledger from SAP.
All variables (DOPEX0301B to DOPEX0314B) Provision for claims from customers	The data is considered actual as it is extracted from the relevant General Ledger from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its financial and other information. The information obtained in the General Ledger is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	JEN receives claims from its customers for damages to their property as a result of an incident on our network. Some of the claims are estimated by the customers when submitted to JEN. JEN provides for these claims in its SPFR When JEN provides for potential claims, this is carried to variable DOPEX0302B. The provision increases or decreases against a database where the customer service manager tracks the claims. The total of monthly routine accruals is disclosed under "Provisions made in the period, resulting in increases to the existing provisions".

Variable	Source and why actual	Methodology
		Similarly the total of monthly routine reversals is disclosed under "Unused amounts reversed during the period". Due to the nature of the claim provisions, expenses incurred are OPEX in nature. There is no impact to CAPEX, therefore no disclosure in the CAPEX subsections of Table 3.2.3. For CY2014, there are immaterial claims made per information from the relevant General Ledger and the claims database.

Estimated Information

14. No estimated information is provided.

15.

3.3 ASSETS (RAB)

16. JEN submitted its first economic benchmarking RIN (EB RIN) to the AER on 30 April 2014. This document explains our approach to prepare the information required under excel tab 3.3 RAB and demonstrates that the approach to prepare this information for our current RIN response—due on 30 April 2015—is the same approach used in our response last year.

JEN adopted the AER's standard approach to disaggregate its 2014 RAB

17. JEN have rolled-forward the RAB from CY2013 to CY2014 using the AER's prescribed standard approach outlined in the EB RIN.

18. To disaggregate the RAB using the AER's prescribed standard approach—refer to *section 3.3* for more detail—JEN is required to allocate its RAB, in direct proportion to the relevant EB RIN category's share of either:

- total estimated depreciated replacement cost (**DRC**) for 2013, or
- total book value for the regulatory year 2013.

JEN has maintained a consistent methodology to disaggregate its 2014 RAB as we applied in our response to the EB RIN on 30 April 2014

19. To ensure consistency, we have used the 2013 splits[1] to disaggregate the 2014 RAB, which aligns to our methodology for disaggregating the 2006 to 2013 RAB, where we also used the 2013 splits (as per the AER's guidance).

JEN notes that the information relating to the RAB are estimates rather than actuals.

20. Consistent with our previous submission, we note that these RAB variables are estimates rather than actual information for three main reasons—refer to *section 3.3*.

The regulatory asset bases are not final

21. The AER approves JEN's standard control services and alternative control services RAB every five years, with the next iteration expected in April 2016 (through the 2016-20 Electricity Distribution Price Review (**EDPR**)). We note that there may be potential differences between the RABs within the EB RIN and our EDPR regulatory proposal.

Since our EB RIN submission, we made some minor, but key changes

22. Since our submission 2013, we have made three (3) changes to our RAB estimates, namely:

- update to SCS 2010 actual information
- further adjustment in the AER's SCS RAB roll-forward model, and
- update to public lighting capex additions by asset categories for 2010 to 2013.

1 The 'splits' refer to the direct proportion to the relevant EB RIN category's share of either total estimated DRC or total book value.

Update to SCS CY2010 actual information

23. For the *first* change, at the time of last year's submission, we relied on the 2010 regulatory accounting statement (**RAS**) for actual information, but it came to our attention that the information has been re-stated as part of the EB RIN process, and the updated information was not reflected in the RAB disaggregation process.

24. The difference between actual and estimated information for 2010 will be adjusted in 2015, once the AER approves the closing 2015 RAB, through its roll-forward exercise. The AER adjusts the closing 2015 RAB through (a) any capex differential as well as (b) any return on the capex differential that JEN is entitled to earn (which can be either positive or negative).

25. This change results in **no impact** to the opening 2014 SCS RAB.

Further adjustment in the AER's SCS RAB roll-forward model

26. Through last year's submission, JEN made a few adjustments (highlighted in red) to the AER RAB roll-forward model (refer to section 3.3b of the BoP).

27. One of the adjustments made was in relation to the capex differential for 2005, which is taken into account in CY2010 (similar to the adjustment required in CY2015 for any capex differential from CY2010). The above adjustment was reflected (in red) in column G of the "Total actual RAB roll forward" of the AER's RFM.

28. In this year's reporting, it came to our attention that this "Total actual RAB roll forward" sheet is included for presentation purposes only, and did not drive any calculations within the RFM.

29. This same adjustment is now properly accounted for in the "Actual RAB roll forward" sheet, which has the following consequences:

- RAB indexation is calculated as the opening RAB x current year inflation
- The closing 2010 RAB should be $764.20M—which the AER approved back in 2010—but in last year's EB RIN reporting, the closing 2010 RAB was $806.91M
- The difference is due to the capex differential of $42.71M, which was correctly amended by JEN in the "Total actual RAB roll forward" sheet, but not within the "Actual RAB roll forward" sheet
- This impacts the RAB indexation calculation, which ultimately impacts regulatory depreciation (calculated as straight-line depreciation less RAB indexation), and
- Because the closing 2010 RAB was over-stated, the RAB indexation was higher—meaning regulatory depreciation was under-stated—and ultimately resulted in an over-stated opening 2014 RAB.

30. This change results in **a positive impact of $3.65M impact** to the opening 2014 SCS RAB.

Update to public lighting capex additions by asset categories for 2010 to 2013

31. To estimate our alternative control services (ACS) RAB, we used the AER approved public lighting model, which includes a RAB roll-forward section.

One of the inputs required in the AER's RFM calculation is net capex by the following asset classes:

- poles and brackets
- luminaires, and

- luminaires and ballasts.

32. In our annual RIN reporting, public lighting capex additions are reported as either (a) energy efficient lights or (b) non-energy efficient lights.

33. In our previous EB RIN submission, we made notional and high level assumptions about how to allocate these net capex additions to the three relevant asset classes.

34. Since then, we have reviewed (and refined) these assumptions by adopting a mapping process at a more granular level, which we believe results in a more appropriate reflection of our expenditure on public lighting.

35. This change results in **a positive impact of $120,892** to the opening 2014 ACS RAB.

3.3.1 REGULATORY ASSET BASE VALUES

Actual Information

36. No actual information is provided.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB0101 – DRAB0107	These variables are estimated as they are the summation of a series of estimated inputs set out in Table 3.3.2.	Table 3.3.1 is the summation of the individual asset categories in table 3.3.2	None	This is JEN's best estimate as these variables are simply the summation of a series of JEN's best estimates of individual asset categories in table 3.3.2

3.3.2 ASSET VALUE ROLL FORWARD

Actual Information

37. No actual information is provided.

Estimated Information

38. For more detail relating to the variables explained in section 3.3.2 Asset value roll forward and section 3.3.3 Total disaggregated RAB values, please refer to **Attachment 1—JEN EBT allocation model**.

Explain why the variable is estimated and why actual information could not be provided

39. JEN notes that the information relating to the regulatory asset base are estimates rather than actuals.

40. The variables are estimates rather than actual information for three main reasons:

    1. The information relating to the RAB does not meet the AER's definition of actual because this information is not recorded within JEN's financial system and cannot be reconciled to. JEN does not report this information in the normal course of business. As such, this is consistent with the AER's definition of 'estimates'.
    2. JEN was unable to directly allocate the asset categories within the AER's approved RAB for JEN (hereafter referred to as **regulatory categories**) to the AER's economic benchmarking asset categories (hereafter referred to as **EBT categories**). Therefore, an allocation methodology was applied. Also note that JEN does not capture RAB data within its financial systems.
    3. The AER has never approved a network services RAB and therefore it had to be estimated.

41. The sections below provide further detail.

Allocation of regulatory categories to EBT categories

42. The regulatory categories that were able to be directly allocated to EBT categories are set out in table A below.

Table A: Direct allocation of regulatory categories to EBT categories

Regulatory category	EBT category
Standard metering	Meters
Public lighting	Other assets with long lives
SCADA/Network control	Other assets with short lives
Non-network general assets - IT	Other assets with short lives

43. The regulatory categories that were allocated to a group of EBT categories are set out in table B below.

Table B: Allocation of regulatory categories to group of EBT categories

Regulatory category	Group of EBT categories
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
Distribution system assets	Overhead network assets less than 33kV (wires and poles)
	Underground network assets less than 33kV (cables)
	Distribution substations including transformers
Non-network general assets - Other	Other assets with long lives
	Other assets with short lives

44. JEN does not capture data for easements. JEN did not report any values for easements and were intentionally left blank in the template.

Explain the basis upon which the estimate was made and the methodology used

45. JEN rolled forward its SCS RAB by applying the AER's RAB framework. For the regulatory years 2006 to 2010, the SCS RAB reconciles back to the AER's approved roll-forward model (**RFM**).[2] For the regulatory years 2011 to 2013, the AER has not yet approved JEN's RAB as this review process will occur during the next EDPR.

46. To roll-forward its SCS RAB for the most recent three years, JEN applied the AER's final decision relating to the RFM to be used by the distribution network service providers (**DNSPs**).[3]

47. In doing so, two adjustments were made to the RFM:

1. Adjustment made within the "*total actual RAB roll forward*" sheet to take into account the difference between forecast capex and actual capex for the regulatory year 2005 as well as the return on the difference.
2. Adjustment made within the "*Input*" sheet to amend the CPI index (one year lagged) to ensure the nominal capex spent in the regulatory year 2011 is deflated to real 2009-10 dollars using an index of 1.0279 (using a year on year Dec-quarter inflation of 2.79%) instead of 1.26%.

JEN rolled forward its ACS RAB in accordance to the AER's approved public lighting model

48. JEN rolled forward its SCS RAB by applying the AER's RAB framework. For the regulatory years 2006 to 2010, the SCS RAB reconciles back to the AER's approved roll-forward model (**RFM**).[4] For

[2] *AER, Jemena Electricity Networks (Victoria) Ltd, distribution determination, Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012.*

[3] *AER, electricity distribution network service providers, roll forward model, June 2008.*

the regulatory years 2011 to 2013, the AER has not yet approved JEN's RAB as this review process will occur during the next EDPR.

49. To roll-forward its SCS RAB for the most recent three years, JEN applied the AER's final decision relating to the RFM to be used by the distribution network service providers (**DNSPs**).[5]

50. In doing so, two adjustments were made to the RFM:

1. Adjustment made within the "*total actual RAB roll forward*" sheet to take into account the difference between forecast capex and actual capex for the regulatory year 2005 as well as the return on the difference.
2. Adjustment made within the "*Input*" sheet to amend the CPI index (one year lagged) to ensure the nominal capex spent in the regulatory year 2011 is deflated to real 2009-10 dollars using an index of 1.0279 (using a year on year Dec-quarter inflation of 2.79%) instead of 1.26%.

JEN adopted the AER's standard approach to disaggregate its RAB

51. JEN disaggregated its RAB into the EBT categories using the AER's prescribed standard approach, where JEN is required to allocate its RAB, in direct proportion to the relevant EBT category's share of either:

- total estimated depreciated replacement cost (**DRC**) for 2013, or
- total book value for the regulatory year 2013.

52. The DRC was used to estimate the following EBT categories:

- Overhead network assets less than 33kV (wires and poles)
- Underground network assets less than 33kV (cables)
- Distribution substations including transformers
- Overhead network assets 33kV and above (wires and towers / poles etc.)
- Underground network assets 33kV and above (cables, ducts etc.)
- Zone substations and transformers.

53. The book value within JEN's statutory asset register has been used to estimate the following EBT categories:

- Other assets with long lives
- Other assets with short lives.

54. The EBT category 'meters' was populated as a direct allocation from the RAB category 'standard metering'.

JEN has used estimated depreciated replacement costs to allocate its network assets

55. Consistent with the AER instructions, the DRC for each EBT Category was estimated by the following formula:

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[4] *AER, Jemena Electricity Networks (Victoria) Ltd, distribution determination, Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012.*

[5] *AER, electricity distribution network service providers, roll forward model, June 2008.*

***DRC** = Estimated weighted average unit rate replacement costs x physical asset data x weighted average remaining asset lives (existing assets) / weighted average service lives (existing assets), where:*

- The estimated weighted average unit rate replacement costs were estimated using best endeavours, based on most recent project estimates. Due to lack of information, the project sample includes both (a) partially completed and (b) completed projects. The projects within the sample were assigned physical characteristics such as (a) line length in kms and (b) capacity in MVA, based on engineering judgement. The estimated weighted average unit rate is then calculated as the project cost estimates ($) / length line (kms) x capacity (MVA). Importantly, JEN assumed that the same unit replacement costs for both overhead and underground network assets 33kV.
- Physical asset data is sourced from RIN sheet 6 (Physical assets).
- The weighted average remaining asset lives (existing assets) are sourced from table 4.4.2 of RIN sheet 4 (RAB assets).
- The weighted average service lives (existing assets) are based on the lives in table 4.4.1 of RIN sheet 4 (RAB assets), but amended to reflect the service lives of existing assets rather than new assets installed in the relevant year.

56. The estimated DRCs for the regulatory year 2013 were used to allocate the RAB categories to EBT categories for the whole period (2006 to 2013), as per the AER's instructions.

57. **Table C** sets out the DRC that is calculated by applying the prescribed DRC formula. The estimated DRC is explicitly used to derive the percentage allocation for the RAB, and is not indicative of the actual network replacement costs. **Table D** sets out the allocation of RAB categories to EBT Categories based on 2013 DRC.

Table C: 2013 depreciated replacement costs by EBT category

EBT Category	Unit	CY13
Overhead network assets less than 33kV (wires and poles)	$000/km^2/MVA	9,152
Underground network assets less than 33kV (cables)	$000/km^2/MVA	659
Distribution substations including transformers	$000/km/MVA^2	495
Overhead network assets 33kV and above (wires and towers / poles etc.)	$000/km^2/MVA	190
Underground network assets 33kV and above (cables, ducts etc.)	$000/km^2/MVA	7
Zone substations and transformers	$000/km/MVA^2	178

Table D.**:** Percentage allocations of RAB categories to EBT categories based on 2013 DRC

RAB category	Allocation to EBT categories	
Sub-transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)	50.56%
	Underground network assets 33kV and above (cables, ducts etc.)	1.94%
	Zone substations and transformers	47.50%
	Total	100.00%
Distribution system assets	Overhead network assets less than 33kV (wires and poles)	88.81%
	Underground network assets less than 33kV (cables)	6.39%
	Distribution substations including transformers	4.80%
	Total	100.00%

JEN used the relative share of book value to allocate its non-network assets

58. JEN mapped each regulatory category to an EBT category. The relative share of book value was only used to allocate the regulatory category 'non-network general assets – other' to the two EBT categories 'other assets with short lives' and 'other assets with long lives'.

59. **Table E** sets out the resulting allocation of 2013 book value.

Table E. Percentage allocations of regulatory categories to EBT categories based on 2013 book value

Regulatory category	Allocation to EBT categories	
Non-network general assets - Other	Other assets with long lives	6.93%
	Other assets with short lives	93.07%
	Total	100.00%

JEN estimated a network services RAB

60. The AER approved a standard control services (**SCS**) and alternative control services (**ACS**) RAB for JEN during the 2010 electricity distribution price review, but did not approve network services (**NS**) or fee & quote based services (**FQ**) RABs.

61. JEN notes the AER's guidance that the NS RAB is a subset of the SCS RAB. The NS RAB was estimated by removing any portion of assets from the SCS RAB, which relate to the provision of:

- connection services
- standard metering
- public lighting
- fee & quoted based services.

62. JEN faced difficulties identifying assets related to connection services because—unlike standard metering and public lighting—JEN does not have a separate regulatory category for connection services assets.

63. Faced with this difficulty, JEN estimated the NS RAB by:

- step 1—estimating the proportion of total capital contributions related to connection services over 2010 to 2013, where data was available
- step 2—multiplying gross (net) demand connection capex over 2006 to 2013 by this proportion to estimate the gross (net) capex related to connection services
- step 3—using this net capex to estimate the share of the opening 2006 RAB related to connections.

64. No assets were deducted for fee and quote based services because the AER did not approve any FQ RAB.

65. Further detail follows.

66. **Step 1.** The approach starts with total capital contributions for the regulatory years 2010 to 2013 by activity (e.g. medium density housing, dual and multiple occupancy, business supply projects, etc.).

Because JEN does not have a connection services RAB, it assumed that all contributions relating to business supply projects and low density & small business supplies <10kvA are associated with connection services.

67. This represents an average of 43% over the four years, calculated using the following:

68. **Portion of connection services** = (CC1 + CC2) / total capital contributions, where:

  69. ***CC1 =*** *capital contributions relating to business supply projects*

  70. ***CC2 =*** *capital contributions relating to low density & small business supplies <10kvA.*

71. **Step 2.** To then determine the gross capex and capital contributions amounts (relating to connection services) for the whole period (2006 to 2013), JEN applied the above percentage to the gross demand connection capex and total contributions to the regulatory years 2006 to 2009.

72. **Step 3**. JEN also identified an estimated portion of the opening distribution system assets RAB (2006), that relates to connection services based on the relative proportion of net connection services capex to net distribution system assets capex for the whole period.

73. The formula used is set out below:

74. **Opening 2006 RAB (connection services)** = Cp:Dp x opening 2006 RAB, where:

> ***Cp:Dp*** *= Ratio of net connection services capex to ratio of net distribution system assets capex*
>
> ***Net capex*** *= gross capex less capital contributions*
>
> ***Opening 2006 RAB*** *= AER approved 2006 opening RAB for distribution system assets.*

75. The identified opening connection services RAB was then rolled-forward in accordance with the AER's RAB framework, using connection services capex, customer contributions and asset disposals. The regulatory depreciation for the connection services net capex was assumed to be a portion (calculated above) of the regulatory depreciation for distribution system assets.

Explain the assumptions made when applying the chosen methodology

JEN interpreted the AER's guidance to use DRC for the regulatory year 2013 retrospectively

- When calculating depreciated replacement costs, JEN interprets the AER's instruction "*where disaggregation is required for the whole period then this will be the 2013 regulatory year*" to mean that the DRC estimates for the regulatory year 2013 are used to allocate the regulatory categories to the network-related EBT categories for the regulatory years 2006 to 2013. The same approach was used to allocate regulatory categories to non network-related EBT categories based book values.
- When calculating the DRC estimates, JEN applied the weighted average service lives of *existing assets*, rather than *new assets*.

JEN made assumptions to estimate a notional NS RAB

- The 2006 opening RAB for connection services was assumed to equal the historical (2006 to 2013) cumulative share of connection related net capex, multiplied by the opening RAB of distribution system assets.
- The proportion of capital contributions related to connection services over 2006 to 2009 equals the average proportion over 2010 to 2013.
- The activities that relate to connection services are assumed to be business supply projects and low density & small business projects <10kvA.
- The proportion of gross connection services capex over 2006 to 2013 related to connection services is the same as the equivalent proportion for capital contributions over this period.
- RAB escalation and straight line depreciation for connection services equals the equivalent value for the SCS RAB multiplied by the share of the opening SCS RAB related to connection services.

JEN made other general assumptions to estimate the RABs

- All information is presented in nominal dollars.
- All information is presented to the nearest thousand ($000), rounded to the nearest dollar.
- Straight line depreciation and regulatory depreciation are expressed as positive values.
- Actual additions are assumed to equal gross capex less customer contributions.

- The same allocation percentages were used to allocate RAB categories to EBT categories for each of the RABs (SCS, NS, ACS).
- The AER approved adjustments to the SCS RAB in the regulatory year 2010 (accounting for the difference between forecast and actual capex incurred in the regulatory year 2005) has been incorporated as an addition to the closing asset value in that year. This explains why the closing value does not equal the opening value plus actual additions less disposals less regulatory depreciation in the regulatory year 2010.

76. The assets that were added to the AER approved ACS RAB in 2010 was incorporated as an addition to the closing asset value in that year. This explains why the closing value does not equal the opening value plus actual additions less disposals less regulatory depreciation in the regulatory year 2010.

Explain why the estimate is JEN's best estimate given the information sought

77. JEN uses, where possible, data that are within its financial system, AER approved data and its best endeavours when estimating the relevant RABs.

78. JEN's best estimate follows, as close as possible, the AER's explanatory statement, instruction and definition document or the AER's preferred methodology for rolling forward RABs, such as:

- using ABS data to estimate actual CPI
- applying the RAB framework to roll-forward its RAB, and
- adopting the standard allocation approach to disaggregate its RAB.

For financial information only: Identify whether accounting policies materially changed during any of the years covered within the Notice

No

Only if response to above was yes: Explain the nature of the change identified in e. and the impact of that change

Not Applicable

3.3.3 TOTAL DISAGGREGATED RAB ASSET VALUES

Actual Information

79. No actual information is provided.

Estimated Information

80. Variable DRAB1201 – 1210 - These variables are assumed to equal the average of the opening and closing value (for each asset category) in Table 4.2. This is consistent with the AER's guidance in its explanatory statement.

81. Variable DRAB13 - AER approved actual values for Standard Control Services and Alternative Control Services. Network Services values are allocated in the same way as described above for variables DRAB0201 – DRAB1107.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB1201 - 1210	JEN considers these variables to be estimates as they are a function of estimated variables.	These variables are the summation of variables DRAB0201 – DRAB1107	n/a	Refer to section 3.3.2
DRAB13	Refer to page 39 above 'JEN made assumptions to estimate a network services RAB'	Refer to page 39 above 'JEN made assumptions to estimate a network services RAB'	Refer to page 39 above 'JEN made assumptions to estimate a network services RAB'	Refer to page 39 above 'JEN made assumptions to estimate a network services RAB'

3.3.4 ASSET LIVES

Actual Information

1. Assets applicable to ACS are public lighting only. These apply to the long asset lives category (DRAB1408, DRAB1508).
2. All assets for SCS have the same estimated service life for network services because connection fees in SCS does not affect the estimated average life of the assets, except for DRAB1401, DRAB 1402, DRAB1501, DRAB1502. Services assets apply to the category of DRAB1401, DRAB1402, DRAB 1501, DRAB1502 and are only included in SCS Section.

Variable	Source and why actual	Methodology	Assumptions
DRAB1401, DRAB1402, DRAB1403, DRAB1404, DRAB1405, DRAB1406, DRAB1407 DRAB1408, DRAB1409	JEN considers this information to be actual as it is captured in the following internal business records: JEN's Geographical Information System (**GIS**) and SAP Plant Maintenance Module (PM) is the source of actual volume data. The actual data was obtained by extracting data directly from GIS and SAP at the end of 2014. The unit rate is obtained from projects completed in 2014. The unit rates have been determined from the project costs and have been extracted from the Plant Maintenance and Project systems Modules of SAP, JEN's Works Management system.	Refer to Economic Benchmarking RIN – Instructions and Definitions: JEN reported asset lives for all RAB Assets in accordance with the category definitions provided in chapter 9. Find $ proportion for each asset: Asset A Proportion = (Unit Rate * Total Installed in 2014) / SUM of total spent per Asset Category X in 2014 as per RAB Asset A = Asset A Proportion * Total Expenditure in 2014 for Asset Category X Asset B Proportion = (Unit Rate * Total Installed in 2014) / SUM of total spent per Asset Category X in 2014 as per RAB Asset B = Asset B Proportion * Total Expenditure in 2014 for Asset Category X Please note Asset A and Asset B are in the group of Asset Category X. Find weighted average life for each asset: Weighted average asset life calculation for assets:	Nil

Variable	Source and why actual	Methodology	Assumptions
		category $j = \sum_{i=1}^{n} \frac{x_{i,j}}{RC_j} . EL_{i,j}$ Where: n is the number of assets in category j $x_{i,j}$ is the value of asset in i in category j $El_{i,j}$ is the expected life of asset i in category j RC_j is the sum of the value of all assets in category j As the weightings are all based on RAB share, this approach is used: If Asset Category X contains 2 assets and Asset A has a useful life of 50 years and a value of $3 million and Asset B has a useful life of 20 years and a value of $2 million, then the weighted average asset life of assets in this category is 38 years: [(3/5) x 50] + [(2/5) x 20] = 38. The asset useful life for each asset is obtained from ELE PR 0012 – Network Asset Useful Lives procedure. The asset volume installed in 2014 is obtained from GIS and SAP and the methodology to obtain the asset volumes is outlined in JEN PR 0506 – RIN Asset Installation Procedure.	
DRAB1501, DRAB1502, DRAB1503, DRAB1504, DRAB1505,	JEN considers this information to be actual as it is captured in the following internal business records: JEN's Geographical Information System (**GIS**) and SAP Plant Maintenance Module (PM) is	Refer to Economic Benchmarking RIN – Instructions and Definitions: JEN reported a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409)	Nil

Variable	Source and why actual	Methodology	Assumptions
DRAB1506, DRAB1507, DRAB1508, DRAB1509	the source of actual volume data. The actual data was obtained by extracting data directly from GIS and SAP at the end of 2014. The unit rate is obtained from projects completed in 2014 as what reported in SAP.	will deliver the same effective service as that asset class did at its installation date. Find weighted average life for each of the assets in one asset category. For each year -> calculate remaining years * total installed (from 1910 – 2013, note we exclude 2014 here because 2014 asset is calculated in previous section as it is being treated as new asset installed). Sum of all total installed Asset A * remaining years. Calculate weighted average life for an Asset A = Sum of all (total installed Asset A * remaining year) / Total asset installed. Once each asset's weighted average life is obtained, we applied this formula to calculate the asset category's weighted average remaining life: $\text{category } j = \sum_{i=1}^{n} \frac{x_{i,j}}{RC_j} . EL_{i,j}$ Where: *n* is the number of assets in category *j* $x_{i,j}$ is the value of asset in *i* in category *j* $El_{i,j}$ is the expected life of asset *i* in category *j* RC_j is the sum of the value of all assets in category *j* As the weightings are all based on RAB share,	

Variable	Source and why actual	Methodology	Assumptions
		this approach is used: If Category X contains 2 assets and Asset A has an expected life of 50 years and a value of $3 million and Asset B has an expected life of 20 years and a value of $2 million, then the weighted average asset life of assets in this category is 38 years: [(3/5) x 50] + [(2/5) x 20] = 38. Please note: the asset value for each asset category is the total RAB value of that asset category up to year 2013. The asset useful life for each asset is obtained from ELE PR 0012 – Network Asset Useful Lives procedure. The asset volume installed in 2014 is obtained from GIS and SAP and the methodology to obtain the asset volumes is outlined in JEN PR 0506 – RIN Asset Installation Procedure.	

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
Network services and alternative control services	JEN has intentionally left variables DRAB1407 and DRAB1507 blank. This is consistent with the AER's explanatory statement where network services are defined as a subset of standard control services—i.e. network services excludes metering, connection services, public lighting and fee based and quoted services. Consequently, JEN has excluded metering asset service and residual lives from the network services section and included asset service and residual lives for public lighting within the ACS section (under the category "Other" assets with long lives—DRAB 1408 and DRAB1508). JEN has also not reported any asset service and residual asset lives for the following variables (DRAB1401-DRAB1406, DRAB1409 and DRAB1501-DRAB1506, DRAB1509) within the ACS section because the only asset that resides within JEN's ACS RAB is public lighting.			

3.4 OPERATIONAL DATA

3.4.1 ENERGY DELIVERY

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOPED01	The data is sourced from JEN's two billing systems. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DOPED01**: Sum of Peak energy, Off Peak energy and Shoulder energy all tariff codes.
DOPED0201 – DOPED0206	The data is sourced from JEN's two billing systems. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DOPED0201:** Comprises of peak energy for A100 and A200 tariff codes. **DOPED0202:** Comprises of Peak energy for all tariff codes with the exception of A100, A200 and A290. **DOPED0203:** Comprises of Shoulder energy for all tariff codes. **DOPED0204:** Comprises of all Off-Peak energy for all tariff codes with the exception of A180 and

Variable	Source and why actual	Methodology	Assumptions
			A290. **DOPED205:** Comprises of Off Peak energy for A180 tariff code **DOPED206**: Comprises of Peak energy and off peak energy for A290 tariff code.
DOPED0404	JEN considers this information an actual as energy received into JEN from embedded generation is extracted from the JEN system called Interval Meter Store (**IMS**).	The generation data for each embedded generators is obtained from IMS and then provided the summation. The data includes the energy received from non-residential embedded generation with capacity greater than 1 MW on an accumulation basis. The embedded generators included are: Austin Hospital (installed 1991) Bioscience Research Centre (Installed 2011) EDL – Bolinda Landfill (installed 1993) EDL – Brooklyn Landfill (installed 2002) LaTrobe University (installed early 1990s) Preston Mini Hydro (installed 2008) Visy (installed 2012) Embedded generators excluded are: Somerton Power Station (installed 2002)	The data is embedded generation data only; it does not include the energy consumed by embedded generation.
DOPED0501- DOPED0505	The data is sourced from JEN's two billing systems. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LC2014.xls on a monthly basis and is summated in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER. **DOPED0501**: Comprises of peak energy, off peak energy and shoulder energy for A100 to A180 tariff codes. **DOPED502:** Comprises of peak energy, off peak energy for A200, A210 and A250 tariff codes.

Variable	Source and why actual	Methodology	Assumptions
	economic benchmarking November 2013.		**DOPED503:** Comprises of peak energy, off peak energy for A230, A250, and A300 to A37R tariff codes. **DOPED504**: Comprises of peak energy, off peak energy for A400 to A50E tariff codes. **DOPED505:** Comprises of peak energy and off peak energy for A290 tariff code.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPED0301 - DOPED0304	The TNSP data obtained by JEN is a monthly value; this value is not split between peak, shoulder or off peak energy. For this reason it is only the allocation between peak and off peak that is an estimate and not the total value.	The estimate is made upon the following basis: Total TNSP data for each calendar year is allocated to the following peak and off peak percentages. Peak and Off peak percentages are based on the following; Total energy delivered (excluding tariffs A100, A200, and A10x shoulder period only) Total Peak energy (excluding A100 and A200) Total Off Peak Energy Peak percentage is equal to; Total peak energy for each calendar year / total energy delivered for each calendar	The estimate is based on the assumption that the peak and off peak percentage of TNSP energy is the same to that of the Energy delivered as reported to the business.	It is JEN’s best estimate as we believe it is reasonable to assume the JEN output energy peak and off peak profile should be in line with the input energy profile which is the energy received from TNSP.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		year. Off Peak percentage is equal to; Total Off peak energy for each calendar year / total energy delivered for each calendar year. DNSP is actual data obtained from monthly invoices sent / received to other DB's. This information is split between peak and off peak. The TNSP peak energy and DNSP peak energy are added to obtain total peak energy. The TNSP off peak energy and DNSP off peak energy are added to obtain total off peak energy.		
DOPED0401 to DOPED0403	JEN does not record data for variables (DOPED0401- DOPED0403). The energy received from Embedded Generation on an accumulation basis is provided under the variable DOPED0404.			

3.4.2 CUSTOMER NUMBERS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOPCN0101 - DOPCN0104	JEN's CIS Plus and SAP ISU systems are the source of actual data for network customer numbers. The above systems do not split customer numbers by tariff types. Customer accounts by tariff type are based on the Billing system The difference of total average customer numbers from CIS Plus and SAP ISU against the weighted average number from the billing system is 1.6% which is not material and therefore the calculated customer number by tariff type is considered as actual. .	Data collection and verification procedures JEN PR 0017 is the procedure to extract distribution customer numbers for the whole network as defined in the RIN definition of Distribution customers – all active NMIs including unmetered supply points; disconnected and abolished NMI are excluded. The percentage split of customers by tariff type is provided by Commercial Performance based on information from the billing system. The percentage split is then applied to the total network customers to calculate customer numbers by tariff type.	No assumptions have been made.
DOPCN0105	Jemena's Customer Information System (**CIS Plus**) and SAP ISU systems are the source of actual data for customer numbers.	The data is extracted from CIS Plus by running a SAS report.	No assumptions have been made.
DOPCN0106	Jemena does not have any customers which fit into the "Other Customer Numbers" category and is therefore entered as zero.		
DOPCN0202 - DOPCN0203	JEN's CIS Plus and SAP ISU systems are the source of actual data for customer numbers. The definition of urban and rural short feeders has been used to determine the categorisation	Data collection and verification procedures JEN PR 0017 is the procedure to extract distribution customer numbers for the whole network as defined in the RIN definition of Distribution customers – all active NMIs including unmetered supply points; disconnected and	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
	of each feeder and adjusted based on the nature of use of the feeder. Urban and rural short feeder customer numbers are extracted from the network model which is generated by the Geographic Information System (GIS). Although the total number of customers from the Geographic Information System (GIS) network model does not exactly match the total network customer numbers extracted from SAP ISU and CIS Plus (SAS) systems, the discrepancy is only 0.044% and is not material. Therefore the calculated urban and rural short customer numbers are considered as Actual	abolished NMI are excluded. Customer numbers by feeder is extracted directly from the network model built in OMS at the first business day of each month. Customers at the start of the period = customer numbers at the first business day of January in the current reporting year and Customers at the end of the period = customer numbers at the first business day of January in the following reporting year. The definition of urban and rural short feeders has been used to determine the categorisation of each feeder and adjusted based on the nature of use of the feeder at the end of the year JEN PR 0502 Section 3.2.3.1 outlined the methodology that JEN has applied to calculate urban and rural customer numbers which basically derives the urban/rural short customer split ratio from the categorised feeder customer numbers at the start of the period and at the end of the period. The ratios are then applied to the actual network customer numbers respectively to calculate the number of urban and rural short customers.	
DOPCN0201and DOPCN0204	JEN has no customers of this type on its network and is therefore entered as zero.	DOPCN0201and DOPCN0204	JEN has no customers of this type on its network and is therefore entered as zero.
DOPCN0301 DOPCN0302	Jemena's Customer Information System (**CIS Plus**) and SAP ISU systems are the source of actual data for customer numbers.	The data is extracted from CIS Plus by running a SAS report	DOPCN0105 is defined and has been reported and therefore DNPCN0301 is actual.

Variable	Source and why actual	Methodology	Assumptions
	DOPCN0301 = DOPCN0105 DOPCN0302 is reported as zero		

Estimated Information

82. No estimated information is provided.

3.4.3 SYSTEM DEMAND

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOPSD0101	JEN considers this information is actual as it can be directly drawn from the internal business records. The information is obtained from SCADA metering data. Throughout the JEN network there is a significant number of measurements (voltage and current), predominantly at JEN zone sub-stations, being provided to the Real Time Systems. All historical SCADA data (2008 onwards) can be interrogated using PI (user interface developed by OSIsoft) JEN has referred to the following report to obtain the data. JEN maximum demand forecast excel spread sheet 2014. Note: PI is the proprietary software	This is derived from metered actual zone substation data, adjusted for abnormal changes—un-anticipated temporary load changes due to transfers, interruption caused for network contingencies—but excludes any embedded generation. $$MD = \sum_{1}^{n} MD_{ZSSn}$$ Where MD = non-coincident summed raw unadjusted annual maximum demand at ZSS level (MW) n = number of JEN zone substations MD_{ZSSn} = non-coincident raw unadjusted annual maximum demand at ZSS n (Mega Watts (**MW**))	The data includes JEN owned zone substations only (i.e. it does not include the customer substation and other DNSP owned zone substations).

Variable	Source and why actual	Methodology	Assumptions
	developed by OSIsoft. The historical SCADA data can be interrogated using PI.		
DOPSD0104	JEN considers this information is actual as it can be directly drawn from the internal business records. The source of actual information is PI system which stores the historical SCADA metering data. JEN has referred to the following report to obtain the data. JEN maximum demand forecast excel spread sheet model 2014.	The coincident maximum demand data for each zone substation is extracted from PI at the time of coincident system peak demand at the transmission network connection points and provided the summation. $$MD = \sum_{1}^{n} MD_{ZSSnt}$$ Where MD= coincident summated raw system annual maximum demand at Zone Substation level (MW) n = number of JEN Zone Substations t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{ZSSnt} = coincident raw unadjusted annual maximum demand at Zone Substation n (MW) at time t.	JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand. Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.
DOPSD0107	JEN considers this information is actual as it can be directly drawn from wholesale market meter data.	This is derived from metered actual (transmission network connection point 15 min-data excluding any embedded generation adjustment. $$MD = \sum_{1}^{n} MD_{TCPn}$$	This includes JEN load flowing on JEN's subtransmission network only. E.g. Thomastown zone substation (TT) station load is excluded as TT load is supplied by non-JEN subtransmission lines.

Variable	Source and why actual	Methodology	Assumptions
		Where MD = non-coincident summed raw system annual maximum demand at Transmission Connection Point level (MW) n = number of JEN Transmission Connection Points MD_{TCPn} = non-coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MW)	
DOPSD0110	JEN considers this information is actual as it can be directly drawn from wholesale market meter data.	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. This is the actual, unadjusted (i.e. not weather normalised) summation of actual raw demands for the transmission connection points at the time when this summation is greatest. The Maximum Demand (**MD**) does not include Embedded Generation. $$MD = \sum_{1}^{n} MD_{TCPnt}$$ Where MD = coincident summed raw system annual maximum demand at Transmission Connection Point level (MW) n = number of JEN Transmission Connection Points t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{TCPnt} = coincident raw unadjusted annual	This includes JEN load flowing on JEN subtransmission network only. E.g. TT station load is excluded as TT load is supplied by non-JEN subtransmission lines.

Variable	Source and why actual	Methodology	Assumptions
		maximum demand at Transmission Connection Point n (MW) at time t	
DOPSD0201	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. The source of actual information is PI system which stores the historical SCADA metering data.	The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $MD = \sum_{1}^{n} MD_{ZSSn}$ Where MD = non-coincident summated raw system annual maximum demand at Zone Substation level (MVA) n = number of JEN Zone Substations MD_{ZSSn} = non-coincident raw unadjusted annual maximum demand at Zone Substation n (MVA) The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $MVA = \sqrt{(MW^2 + MVAr^2)}$ The source of MW and MVAr information is PI system and JEN maximum demand forecast excel spread sheet model 2014.	The MVAr comes after the application of power factor correction measures at zone substation (e.g. capacitor bank), where applicable. The data includes JEN owned zone substations only (i.e. it does not include the customer substation and other DNSP owned zone substations).

Variable	Source and why actual	Methodology	Assumptions
DOPSDO204	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. The source of actual information is PI system which stores the historical SCADA metering data.	The zone substation MW MD and MVAr from PI at the time of system peak are utilised to estimate the data as per the definition of this variable. The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $MD = \sum_{1}^{n} MD_{ZSSnt}$ Where MD_x = coincident summed raw system annual maximum demand at ZSS level (MVA) n = number of JEN zone substations t = time of system coincident maximum demand at transmission connection point level MD_{ZSSnt} = coincident raw annual maximum demand at ZSS n (MW) at time t The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $MVA = \sqrt{(MW^2 + MVAr^2)}$	JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand. Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.
DOPSD0207	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data and JEN maximum demand forecast excel spread sheet model 2014 are the sources of actual	The MVA MD is calculated from metered actual (transmission connection point 15 min-data) MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD.	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.

Variable	Source and why actual	Methodology	Assumptions
	data.	$$MD = \sum_{1}^{n} MD_{TCPn}$$ Where MD = non-coincident summed raw system annual maximum demand at Transmission Connection Point level (MVA) n = number of JEN Transmission Connection Points MD_{TCPn} = non-coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MVA) The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of MW and MVAr data.	MVA MD is assumed to occur at the same date and time as MW MD
DOPSD0210	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data and JEN maximum demand forecast excel spread sheet model 2014 are the sources of actual data.	MW MD is derived by summation of metered actual raw demands for the transmission connection points (terminal station average 15-min data) at the time when this summation is greatest. The MVA MD is calculated from metered actual of MW MD and MVAr at the time of MW MD therefore MVA MD is the same date and time as MW MD. $$MD = \sum_{1}^{n} MD_{TCPnt}$$ Where	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible. MVA MD is assumed to occur at the same date and time as MW MD.

Variable	Source and why actual	Methodology	Assumptions
		MD = coincident summated raw system annual maximum demand at Transmission Connection Point level (MVA) n = number of JEN transmission connection points t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{TCPnt} = coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MVA) at time t The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $MVA = \sqrt{(MW^2 + MVAr^2)}$ Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of MW and MVAr data.	
DOPSD0301	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data is the sources of actual MW and MVAr data.	As per the Economic Benchmarking RIN definition of power factor $\text{The average overall network power factor} = \frac{\sum_{x=1}^{x=n} MW_x}{\sum_{x=1}^{x=n} MVA_x}$ MW_x = Sum of MW measured in every 15 minute average interval by wholesale market meters in JEN sub transmission connection points MVA_x= Sum of MVA calculated from MW_x and corresponding MVAr measured in every 15 minute average interval by wholesale market meters in JEN sub transmission connection	None.

Variable	Source and why actual	Methodology	Assumptions
		points	
DOPSD0311	JEN considers this information is actual as it is calculated from actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data is the sources of actual MW and MVAr data.	As per the Economic Benchmarking RIN the definition of power factor The average overall network power factor $= \frac{\sum_{x=1}^{x=n} MW_x}{\sum_{x=1}^{x=n} MVA_x}$ MW_x = Sum of MW measured in every 15 minute average interval by wholesale market meters in JEN 66kV sub transmission connection points MVA_x= Sum of MVA calculated from MW_x and corresponding average MVAr measured in every 15 minute average interval by wholesale market meters in JEN 66kVsub transmission connection points	The data for this variable is different from DOPSD0301 as DOPSD0301 includes both 66kV and 22kV sub transmission connection points.
DOPSD0401	JEN's billing is based on measured maximum demand, not on an assumed contracted rate. JEN can therefore not currently provide this information.		
DOPSD0402	The data is sourced from JEN's two billing systems. The data is then captured in the LC2014.xls on a monthly basis and is summed in worksheet Year to date. The information obtained in the reports is actual information as it is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LC2014.xls on a monthly basis and is summed in worksheet Year to date.	None.

Variable	Source and why actual	Methodology	Assumptions
DOPSD0403-DOPSD0404	JEN does not currently record maximum demand as MVA.		

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPSD0102, DOPSD0103, DOPSD0105, DOPSD0106, DOPSD0108, DOPSD0109, DOPSD0111, DOPSD0112, DOPSD0202, DOPSD0203, DOPSD0205, DOPSD0206, DOPSD0208, DOPSD0209, DOPSD0211, DOPSD0212,	The data for these variables is estimated as it is calculated based on assumptions rather than extracted directly from metered data.	Coincident/Non-coincident summated weather adjusted MW MD at zone substation level / transmission connection point are derived by summation of respective weather adjusted MW MDs of individual zone substation / transmission connection point $Weather\ adjusted\ MW\ MD = \sum_{1}^{n} MD_b$ Where: n = number of JEN transmission connection points/JEN owned zone substations $MD_b = MD_a \times \frac{A.t_b^2 + B.t_b + C}{A.t_a^2 + B.t_a + C}$ A, B, C = coefficients determined based on historical data for each station. These values are as recorded in the load demand forecast. MD_b = MW MD after temperature adjustment MD_a = actual unadjusted MW MD t_b = average daily temperature to adjust to (32.9°C for 10% POE or 29.4°C for 50% POE) t_a = average daily temperature on day of actual unadjusted MW MD	It is assumed that the 10% POE and 50% POE average daily temperatures and MD temperature sensitivity relationship is consistent for 2014.	This is the well-established method in engineering practice for MD temperature adjustment. JEN is not aware of a superior technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Average daily temperature is calculated as follows: $$t = \frac{(t_{max} - t_{min})}{2}$$ Where: t = average daily temperature t_{max} = maximum temperature of the day (24 hour period) (data sourced from PI) t_{min} = minimum temperature of the day (24 hour period) (data sourced from PI) Weather corrected values are assumed to have the same MW/MVA ratio as raw adjusted data. Therefore weather corrected MVA is calculated as: $$\mathrm{MVA_{adjusted}} = \frac{\mathrm{MVA_{raw}}}{\mathrm{MW_{raw}}} \times \mathrm{MW_{adjusted}}$$		
DOPSD0302	The variable is estimated due to the assumptions made and that it could not be directly drawn from JEN's internal business records.	MW and MVA data measured during 2014 for 9 distribution substations (3 commercial, 3 industrial and 3 domestic loads) are utilised to estimate this variable. The data were captured via power quality meters in every 1 minute interval for around 7 days in each substation. The power quality meters were installed at different dates and time. $$\text{The average power factor for the LV network} = \frac{\sum_{x=1}^{n} MW_x}{\sum_{x=1}^{n} MVA_x}$$ MW_x = MW measured in every 1 minute for a week in	In the normal course of business JEN does not record power factor of each individual LV lines. It is assumed that the average power factor of this sample of 9 distribution substations (3 domestic, 3 commercial and 3 industrial loads) gives fair estimate of LV power factor.	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		substation x. MVA_x= MVA measured in every intervals as MW measured in substation x		
DOPSD0303, DOPSD0305, DOPSD0307, DOPSD0309, DOPSD0310, DOPSD0312, DOPSD0313, DOPSD0314	These variables are not applicable to JEN as JEN does not have any lines with these voltage levels.			
DOPSD0304, DOPSD0306, DOPSD0308	The variable is estimated due to the assumptions made and that it could not be directly drawn from JEN's internal business records.	As per RIN requirement the Total MW and MVA are calculated as below. $$\text{Total MVA} = \sum_{x=t1}^{tn} a_x + \cdots \sum_{x=t1}^{tn} n_x$$ Where t1 … tn are 15 minute time intervals from 1 January to 31 December. The feeder currents are recorded in every 15 minute interval in OSI PI. $a_x \ldots n_x$= Feeder MVA at time interval x =$\sqrt{3}$ X nominal voltage of the feeder X Feeder current at time interval $$\text{Total MW} = \sum_{x=t1}^{tn} A_x + \cdots \sum_{x=t1}^{tn} N_x$$ Where, $A_x \ldots N_x$= Feeder MW at time interval x	The data provided excludes customer substations and other DNSP owned zone substations for HV feeders	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Average power factor = $\frac{\text{Total MW}}{\text{Total MVA}} = \frac{\sum_{x=t1}^{tn} a_x + \cdots \sum_{x=t1}^{tn} n_x}{\sum_{x=t1}^{tn} A_x + \cdots \sum_{x=t1}^{tn} N_x}$ Since only the historical interval data for zone substation MW and Feeder currents are available, the above equation is simplified as below by dividing the numerator and denominator by the number of time intervals Average power factor = $\frac{\text{Total MW}}{\text{Total MVA}} = \frac{\text{Average MW of zone substation } 1 + \cdots + \text{Average MW of zone substation N}}{\text{Average MVA of Feeder } 1 + \cdots + \text{Average MVA of feeder N}}$ The zone substations and the feeders in above equation are at same voltage level		

3.5 PHYSICAL ASSETS

3.5.1 NETWORK CAPACITIES

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DPA0101-DPA0114	JEN's Geographical Information System (**GIS**) is the source of actual data for network length.	The GIS is the key source of the network connectivity model. The overhead conductors have the voltage and length as attributes and therefore we allocate the conductors into the required categories. The actual data was obtained by extracting data	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
		directly from GIS at the end of 2014. 22kV subtransmission has been included in the Overhead 22kV categorisation.	
DPA0201-DPA0212	As above.	The GIS is the key source of the network connectivity model. The underground cables have the voltage and length as attributes and therefore we are able to allocate the conductors into the required categories. The actual data was obtained by extracting data directly from GIS at the end of 2014. 22kV subtransmission has been included in the Underground 22kV categorisation.	As above
DPA0102, DPA0104, DPA0106, DPA0108, DPA0109, DPA0111-DPA0114, DPA0202, DPA0204, DPA0206, DPA0208, DPA0210-DPA0212	JEN does not have any 2.2kV, 7.6kV, SWER, 33kV, 44kV, 110kV, 132kV, 220kV or “Other” lines, therefore the data in the relevant cells are zero.		

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DPA0301	JEN has estimated the data for this variable because it is calculated and is not an actual, measured value.	$Weighted\ average\ Capacity\ of\ LV\ OH\ \ line\ in\ year\ X = \frac{\sum_1^n \ s_n l_n}{\sum_1^n \ l_n}$ Where: n = number of sections of LV conductor in service on JEN network s_n= MVA rating of section n of LV OH conductor l_n= length of section n of LV OH conductor. The data for length, size and type of conductor is extracted for GIS.	As per the size and type of conductor recorded in GIS, the ratings of overhead conductors are obtained from historical construction and design manuals used by JEN / its predecessors and current standards If the conductor type and size are unknown in GIS records, those sections are not included in calculation. As JEN is summer peaking network, the summer ratings of overhead line have been utilised to calculate the MVA capacity. The data provided covers more than 61% of total length (as of 31/12/2014) of OH LV recorded in GIS. It is assumed that this sample is a fair representation of the population of LV conductors on the JEN. Single phase and 2 phase lines are not included in the calculation. Service lines are not included in the calculation. As JEN is summer peaking network, the summer ratings of overhead line have been utilised to calculate the MVA capacity.	This approach is the most reasonable given the availability of data.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DPA0303, DPA0305, DPA0307, DPA0308, DPA0310, DPA0311, DPA0312, DPA0313	These variables are not applicable to JEN because JEN does not have any lines with these voltage levels.			
DPA0309	JEN has estimated this variable as it does not currently capture weighted average MVA capacity for sub transmission lines in the normal course of business. As the data is not directly available from JEN's internal business records, a suitable estimate is provided.	$Weighted\ average\ Capacity\ of\ 66kV\ subtransmission\ OH\ line = \frac{\sum_1^n s_n l_n}{\sum_1^n l_n}$ Where: n = number of sections of 66kV conductor existing on JEN network s_n= Summer MVA rating of limiting section of subtransmission line which section n belongs to, regardless of whether limiting section is overhead or underground l_n= length of section n of 66kV OH conductor The data for section length is extracted from GIS.	Only JEN owned subtransmission are included in the calculation. The limiting section ratings of individual lines are sourced from circuit data sheets. As JEN is summer peaking network, the summer ratings of OH conductors have been utilised to calculate the MVA capacity.	This approach is the most reasonable given the availability of data.
DPA0302, DPA0304, DPA0306	JEN has estimated this variable as it does not currently capture the weighted average MVA capacity for HV OH lines in the normal course of	$Weighted\ average\ Capacity\ of\ HV\ OH\ line = \frac{\sum_1^n s_n l_n}{\sum_1^n l_n}$ Where:	In business as usual activities JEN has records of overall nominal ratings of the feeders which are calculated as below. Generally, the capacity of a feeder is limited by the current carrying	This approach is the most reasonable given the availability of data.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	business. As the data is not directly available from JEN's internal business records, a suitable estimate is provided.	n = number of sections of HV conductor existing on JEN network s_n= MVA rating of section n of HV OH conductor l_n= length of section n of HV OH conductor The data for section length is extracted from GIS.	capacity of the overhead or underground sections on the main backbone. The limiting section of a backbone is likely to be close to the zone substation. The overall nominal rating of a feeder is defined as the limiting backbone section of conductor (overhead or underground) where the capacity utilisation is the greatest. The weighted average capacity calculation methodology used does not account for capacity which cannot be utilised due to upstream limitations. As per the size and type of conductor recorded in GIS, the ratings of overhead conductors are obtained from historical construction and design manuals used by JEN/ its predecessors and current standards If the conductor / cable type and size are unknown in GIS records, those sections are not included in the calculations. The data provided covers more than 90% of total length (as of 31/12/2014) of OH HV recorded in GIS. It is assumed that this sample is a fair representation of the population of HV OH conductors on the JEN. All HV lines are assumed to be 3 phase for the purpose of this	

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			calculation. Conductor ratings in manuals/standards are given in Amps, therefore nominal voltage of the line is used to convert to MVA. Variable DPA0306 also includes the data for 22kV OH sub transmission. As JEN is summer peaking network, the summer ratings of OH conductors have been utilised to calculate the MVA capacity.	
DPA0401	JEN has estimated the data for this variable because it is calculated and is not an actual, measured value.	The basis of JEN's estimate is set out in the formula below: $Weighted\ average\ Capacity\ of\ LV\ UG\ line = \frac{\sum_1^n s_n l_n}{\sum_1^n l_n}$ Where: n = number of sections of LV cable existing on JEN network s_n= MVA rating of section n of LVUG cable l_n= length of section n of LV UG cable The data for section length is extracted from GIS.	For the ratings of LV Underground (**UG**) cables, current and historical construction and design manuals used by JEN/its predecessors and current standards have been used. Ratings are based on standard design depth, temperature, proximity to other cables etc and do not allow for any variations from this which may exist in the field. This is due to the absence of this data in GIS. The unknown type and size of cables are not included in the calculations. The data provided covers almost 95% of total length (as at 31/12/2014) of LV UG recorded in GIS. It is assumed that this sample is a fair representation of the population of LV UG cables	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			on the JEN. Only 3 core and 4 core cables are included in the calculation. Underground service cables are not included in the calculation.	
DPA0403, DPA0405, DPA0408	JEN has estimated this variable as it does not currently capture the weighted average MVA capacity for HV underground network in the normal course of business. As the data is not directly available from JEN's internal business records, a suitable estimate is provided.	The basis for JEN's estimate is set out in the formula below: $$Weighted\ average\ Capacity\ of\ HV\ UG\ line = \frac{\sum_1^n s_n l_n}{\sum_1^n l_n}$$ Where: n = number of sections of HV cable existing on JEN network s_n= MVA rating of section n of HV UG cable l_n= length of section n of HV UG cable The data for section length is extracted from GIS.	In business as usual activities JEN has records of overall nominal ratings of the feeders which are calculated as below. Generally, the capacity of a feeder is limited by the current carrying capacity of the overhead or underground sections on the main backbone. The limiting section of a backbone is likely to be close to the zone substation. The overall nominal rating of a feeder is defined as the limiting backbone section of conductor (overhead or underground) where the capacity utilisation is the greatest. The weighted average capacity calculation methodology used does not account for capacity which cannot be utilised due to upstream limitations. For the ratings of HV UG cables, current and historical construction and design manuals used by JEN/its predecessors and current standards have been used. Ratings are based on standard design depth, temperature,	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			proximity to other cables etc and do not allow for any variations from this which may exist in the field. This is due to the absence of this data in GIS. Cable ratings in manuals/standards are provided in Amps, therefore nominal voltage of the line is used to convert to MVA. The unknown type and cross section of conductors are not included in the calculations. The data provided is covers more than 98% of total length (as of 31/12/2014) of HV UG recorded in GIS. It is assumed that this sample is a fair representation of the population of HV UG cables on the JEN network. Variable DPA0408 also includes the data for 22kV UG subtransmission lines.	
DPA0410	JEN has estimated this variable as it does not currently capture the weighted average MVA capacity for 66kV underground lines in the normal course of business. As the data is not directly available from JEN's internal business records, a suitable	The basis of JEN's estimate is set out in the formula below: $Weighted\ average\ Capacity\ of\ 66kV\ subtransmission\ UG\ line = \frac{\sum_1^n s_n l_n}{\sum_1^n l_n}$ Where: n = number of sections of 66kV cable existing on JEN network. s_n= Summer MVA rating of limiting section of subtransmission line which section n belongs to,	Only JEN owned subtransmission is included in the calculation. The limiting section ratings of individual lines are sourced from circuit data sheets.	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	estimate is provided.	regardless of whether limiting section is overhead or underground l_n= length of section n of 66kV UG cable The data for section length is extracted from GIS.		
DPA0402, DPA0404, DPA0406, DPA0407, DPA0409, DPA0410, DPA0411, DPA0412	These variables are not applicable to JEN because JEN does not have any lines with these voltage levels. Therefore any information relating to these variables are not provided			

3.5.2 TRANSFORMER CAPACITIES

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DPA0501	The information was sourced from GIS and is considered actual information as GIS is a direct source of actual information.	The distribution transformer capacity is a characteristic of each of the distribution transformers.	There are no assumptions.
DPA0503	JEN considers this information to be actual information as it can be directly extracted from JEN SAP which has a specific flg as emergency stock.	This is the summation of JEN owned distribution transformers stored in JEN's warehouse as emergency stock.	JEN has applied the assumption that only the capacity that is held in emergency stock should be classified as cold spare capacity. Capacity that is held as stock which is reserved for construction projects has not been classified as cold spare capacity.

Variable	Source and why actual	Methodology	Assumptions
Table 3.5.2.3	JEN does not have Distribution other - transformer capacity	n/a	Distribution other - transformer capacity owned by utility definition is not provided. As all the capacity reported already covered all of JEN owned and all owned by HV Customer, this other - transformer capacity owned by utility is zero
DPA0601, DPA0602	JEN does not have any two-step transformations and has therefore provided no information relating to these variables.		
DPA0603, DPA0604	JEN considers this information to be actual information as it can be directly drawn from JEN's Distribution Annual Planning Report (DAPR) 2014.	This is the summation of JEN owned zone substation transformer normal assigned continuous capacity ratings.	This does not include the customer substation and other DNSP owned zone substations supplying JEN customers. Not all capacities of zone substations are the nameplate ratings of the transformers. Some are de-rated due to limiting capacity of zone substation exit feeder capacity, some due to voltage drop limitation etc.
DPA0605	JEN does not have any cold spare zone substation transformers, as per JEN policy. Therefore no information is provided in relation to this variable.		

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DPA0502	As per the AER RIN explanatory statement where this information is not available to the NSP, it is to report a summation of non-coincident individual maximum demands of each such directly connected customer whenever they occur (ie the summation of a	The maximum demand (MW) for HV customers is extracted from JEN's billing systems. The MW information is thereby converted to MVA using the methodology detailed below. An assumed power factor of 0.9 lagging, as per Electricity Distribution Code Clause 4.3 Table 2, is used to convert the MW MD to MVA MD of individual HV customer. The data provided is the summation of MVA MD	The average JEN HV customer maximum demand is greater than 2MVA, therefore a power factor of 0.9 lagging is assumed to be reasonable as this is the minimum power factor that customers with maximum demand greater than 2MVA must use best endeavours to keep (as per Electricity Distribution Code clause 4.3 table 2).	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	single annual MD for each customer) as a proxy for capacity within the customer's installation. The variable should be the sum of the direct information where this is available and of the proxy MVA measure where the direct measure is not available. JEN does not currently record the distribution transformer capacity owned by high voltage customers and has therefore provided a suitable estimate.	of individual HV customers.	The data provided does not include the sub transmission customers.	

3.5.3 PUBLIC LIGHTING

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DPA0701	JEN's GIS is the single source of actual data for the public lighting inventory. The data is extracted directly from the GIS and is therefore considered to be actual information.	The GIS is the single source of the public lighting physical inventory, therefore JEN are able to count the number of luminaires. The actual data was obtained by running a report directly from GIS.	No assumptions have been made in providing this information.
DPA0702	JEN's GIS is the single source of actual data for the public lighting pole inventory. The data is extracted directly from the GIS and is therefore considered to be actual information.	The GIS is the single source of the public lighting pole physical inventory, therefore JEN are able to count the number of public lighting poles. The actual data was obtained by running a report directly from GIS.	In applying this methodology, it has been assumed that the pole installation and pole removal dates have been accurately recorded in GIS.

Estimated Information

83. No estimated information is provided.

3.6 QUALITY OF SERVICE DATA

3.6.1 RELIABILITY

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DQS0101-DQS0108	JEN considers this information to be actual information as it is maintained directly within its Outage Management System (**OMS**). JEN's OMS is the repository for all outage information, including outage dates and times, the number of customers affected, restoration dates and times and restoration stages. JEN's CIS Plus and SAP ISU systems are the source of actual data for network customer numbers.	The data used to calculate the reliability variables (Key Performance Indicators (**KPI**)) is extracted from the OMS at the end of each month and is validated and cleansed to correct data errors. The cleansed data is loaded into the Customer Minutes Off Supply (**CMOS**) database. The reliability KPI's are then calculated. Unplanned SAIDI associated with outages greater than 1 minute duration was calculated using the following equations: DQS0101-0104 inclusive of MED DQS0101 = Total unplanned SAIDI = sum of Unplanned minutes off supply divided by average network customer numbers at the start and at the end of the regulatory year. DQS0102 = Unplanned SAIDI (excluding excluded outages) applies the same principle of calculation of total unplanned SAIDI with unplanned customer minutes off supply associated with the excluded events as per Clause in 3.3(a) in STPIS subtracted from the	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
		total unplanned minutes off supply before dividing by customer numbers. Similarly Unplanned SAIFI = sum of Unplanned customer interruptions divided by average network customer numbers at the start and at the end of the regulatory year DQS0105-0108 exclusive of MED DQS0105 = DQS0101 DQS0107 = DQS0103 DQS0106 and DQS0108 apply the above calculations with the relevant quantity related to excluded event and MED as per Clause 3.3 in STPIS subtracted from the Total before dividing by customer numbers.	

Estimated Information

84. No estimated information is provided.

3.6.2 ENERGY NOT SUPPLIED

Actual Information

85. No actual information is provided.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DQS0201-DQS0202	JEN has estimated these variables because it is calculated and is not an actual,	The methodology that has been used is the fourth option, outlined on page 37 of “Economic benchmarking RIN for	The planned energy not supplied has been consistently calculated with a factor of 0.3 since 1997. The	JEN has adopted the fourth estimation option for average customer demand because

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
(Note: Data provided for 2006-2013 were incorrect provided in MWh not GWh)	measured value. The energy not supplied has been routinely reported by JEN at the end of each year. JEN has referred to these reports to populate these variables. The feeder maximum demand, load factor, power factor and number of customers are calculated using data from JEN's core asset management systems.	distribution network service providers – Instructions and Definitions (November 2013)" That is, JEN has used the average feeder demand derived from feeder maximum demand, estimated load factor and power factor, divided by the number of customers on the feeder. Planned energy not supplied is increasing over the period due to increasing capital expenditure on the network. The proportion of capex spent on the distribution network (contribution to planned energy not supplied) has increased compared to zone substation capex (no contribution to planned energy not supplied) in the later years of the period. Generally, zone substation projects have little requirement for planned interruptions to customers and therefore little to no contribution to planned energy not supplied. Distribution projects are the dominant contributors to planned energy not supplied. The variation is also dependent on the scope of the projects. Unplanned energy not supplied is dependent on the number of unplanned outages and the nature/damage/date/time/network topology/available capacity etc. of the outages defined the duration of the outages.	assumption has considered that customers have been given notice 4 days before the outage, energy usage would just be diverted to times when supply is available and the actual energy not supplied would only be the base continuous consumption such as operating a fridge. The assumption and the adjustment factor was communicated to the Regulator (Office of the Regulator General (**ORG**)) before the 1997 annual report was submitted. There has been no instruction from the Regulator since indicating that the assumption should not be applied. JEN has used the average feeder demand derived from feeder maximum demand, estimated load factor and power factor divided by the number of customers on the feeder.	all inputs to calculate average customer demand on a feeder are readily available. Options 1-3 could not be considered due to limitations of the IT system to merge the information from various sources.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Unplanned energy not supplied is a function of unplanned customer-minutes-off-supply. As the RIN unplanned energy not supplied definition required the exclusion of excluded outages.		

3.6.3 SYSTEM LOSSES

Actual Information

86. No actual information is provided.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DQS03	JEN has estimated this variable as system loss data is captured internally in financial years (i.e. 1 July to 30 March), not in calendar years. JEN had to therefore convert the data to calendar years (using some assumptions). JEN cannot therefore claim the variable to be actual information.	JEN has adopted the methodology published by the Essential Services Commission (**ESC**) in February 2007 for the determination of distribution loss factors. This methodology is based on the methodology jointly developed by the Victorian distribution businesses, having regard to the principles of clause 3.6.3 (h) of the NER. The calendar year data for 2014 is derived by taking the average of system loss for FY 2013/2014 and FY 2014/15. FY 2013/14 system loss is based on actual energy sales and purchased data while FY 2014/15 system loss is the forecast.	None	This approach is the most reasonable given the current methodology used to calculate Distribution Loss Factor (**DLF**) and definition of the variable.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Wholesale market meter data, embedded generation data, cross boundary flow energy meter data are the sources for historical energy import and export data.		

3.6.4 CAPACITY UTILISATION

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DQS04	JEN considers this variable to be actual information as the data is calculated from the variable code DOPSD0201, which is zone substation raw actual maximum demand (MVA), and variable code DPA0604, which zone substation transformer MVA capacity. Both are sources of actual data and so the derived capacity utilisation should be considered actual information also.	The overall utilisation for JEN owned zone substations is calculated each year by dividing the sum of non-coincident summated raw system maximum demand at the zone substation level by summation of zone substation thermal capacity. $$U_{ave} = \frac{MD_{ZSS}}{C_{ZSS}}$$ Where: U_{ave} = Overall utilisation of JEN owned zone substations MD = sum of non-coincident raw Maximum Demand (MVA) at the zone substation level (only JEN owned zone substations). This is equal to variable DOPSD0201. C_{ZSS} = summation of JEN owned zone substation thermal capacity. This is calculated as DPA0604 minus DPA0605.	As per variable codes DOPSD0201 and DPA0604.

Estimated Information

87. No estimated information is provided.

3.7 OPERATING ENVIRONMENT FACTORS

3.7.1 DENSITY FACTORS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOEF0101	JEN considers this variable to be actual information as the data is calculated from the variable code DOEF0301, which is route line length, and variable code DOPCN01, which is total customer numbers—both are sources of actual data and so the derived customer density should be considered actual information and are directly reconcilable with JEN's internal business records.	The data is calculated by dividing the variable code DOPCN01, which is total customer numbers by the variable code DOEF0301, which is the route line length. It was identified (23 Feb 2015) that when variable code DOEF0301 – Route Line length was corrected in mid-2014 (to include route line length of the JEN underground network) dependent variable codes were missed in the correction. These are variables DOEF0101 – Customer density and DOEF0213 – Standard vehicle access. Refer to Table 8.1.1, directly below, for the corrected back-cast data for variable code DOEF0101 – Customer density.	As per variable codes DOEF0301 and DOPCN01

Variable	Source and why actual	Methodology	Assumptions
DOEF0102	JEN considers this variable to be actual information as the data is calculated from the variable code DOPED01, which is total energy delivered, and variable code DOPCN01, which is total customer numbers—both are sources of actual data and so the derived energy density should be considered actual information and are directly reconcilable with JEN's internal business records.	DOEF0102 is derived as follows: variable DOPED01 is converted to MWh and divided by variable DOPCN01. Formula: (DOPED01*1000)/DOPCNO1	As per variable codes DOPED01 and DOPCN01.
DOEF0103	JEN considers this variable to be actual information as the data is calculated from the variable code DOPSD0201, which MVA non-coincident maximum demand at zone substation level, and variable code DOPCN01, which is total customer numbers—both are sources of actual data and so the derived demand density should be considered actual information and are directly reconcilable with JEN's internal business records.	Calculated as per the definition of variable i.e. kVA non-coincident Maximum demand (at zone substation level)/ no of customers $$DF_x = \frac{MD_x}{C_x}$$ Where: DF_x = Density Factor for year x MD = non-coincident maximum demand at zone substation level (kVA) in year x as per variable code DOPSD0201 x 1000 C = total number of customers on JEN network in year x as per variable code DOPCN01	As per variable codes DOPSD0201 and DOPCN01

88. Table 8.1.1 Corrected back-cast data for variable code DOEF0101 – Customer density

	Unit	2006	2007	2008	2009	2010	2011	2012	2013
Customer density (previously submitted)	Customer / km	91.6724	93.3683	93.8932	94.4702	95.8106	96.7122	97.9277	98.8502
Customer density (corrected)	Customer / km	72.1781	73.0227	72.6932	72.6306	73.1552	73.2207	73.3933	73.4566

Estimated Information

89. No estimated information is provided.

3.7.2 TERRAIN FACTORS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOEF0201	This is an actual number for 2014. JEN's GIS is the single source of actual data for distribution asset inventory. The data is extracted from GIS and is therefore considered actual information.	An actual number is provided for 2014. A list of information relating to all HV lines is extracted from the GIS. In an Excel spreadsheet a pivot table is used to sum all the line sections per feeder. The sum of the feeders defined as rural is then proportioned against the total network Line Length	No assumptions have been made in providing this information.
DOEF0202 - DOEF0204 and DOEF0214	The source of the information is the Vegetation Management System (**VMS**). The data is collected in the field and entered into data collection devices and is then loaded into the VMS. Reports are run directly from the VMS. JEN thereby considers these variables to be actual information as they can be directly drawn from JEN's internal business records.	The data collected in the field and loaded into the VMS includes the feeder that the span is connected to (thus it is possible to determine whether the feeder is in the rural or urban area and whether it is in a bushfire risk area as defined by the Country Fire Authority (**CFA**)).	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
DOEF0205	The source of the information is the JEN GIS Vegetation Management System (**VMS**). The data is collected in the field and entered into data collection devices and is then loaded into the VMS. Reports are run directly from the VMS. JEN thereby considers these variables to be actual information as they can be directly drawn from JEN's internal business records.	Jemena records the number of poles and does not record the number of spans. The total number of spans is the total number of poles less one.	The assumption has been made that public lighting poles are to be included in the total pole number because there are public lighting poles that are serviced overhead as well as underground. The public lighting poles that are serviced underground also receive management to assess and clear vegetation from poles.
DOEF0206 - DOEF0207	The source of the information is the Jemena Electric Line Clearance Management Plan for 2014, which document the actual vegetation maintenance span cycles applied to each of the specified areas.	The methodology that has been used is to determine the optimum cycle which is compliant with the Electric Line Clearance Regulations 2010.	Jemena's Electric Line Clearance Management Plan specifies the cycle times for CFA fire rated areas. For variable DOEF0206 it is assumed that all sections of urban and CBD feeders are within the Low Bushfire Risk Area and all sections of rural feeders are within the Hazardous Bushfire Risk Area.
DOEF0210, DOEF0211	JEN considers this variable to be actual information as the average number of defects per vegetation maintenance span is extracted from process data captured in the VMS. All information can be directly verified via VMS.	The average number of Defects per vegetation Maintenance Span is calculated by dividing the number of Defects (action spans) with maintenance spans at the end of each calendar year. JEN refers to this average as the "find rate" for a given year.	A "defect" is defined as any span which requires cutting (pruning or removal) in the year in question and is known as an "action span" in the VMS.
DOEF0212	JEN considers this variable to be actual information as Victoria has no tropical areas.	Not applicable	No assumptions have been made in providing this information.

Estimated Information

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOEF0208	The Vegetation Management System (**VMS**) does not record	Average number of trees obtained from a physical survey of 150 urban spans	Based on local knowledge the spans selected for survey were assumed to	The estimate is JEN's best estimate because the

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	the number of trees actually requiring maintenance. The VMS records the number of maintenance spans but not the number of trees per maintenance span. Therefore JEN provided an estimate for this information.	conducted in Jan 2014.	be representative of all urban maintenance spans. It is assumed that Jan 2014 survey results are valid for at least one cycle. If a tree was likely to require pruning within the next 5 years it was counted as a tree in that span. Locations for the survey were chosen on experience so as not to overstate or understate the average number of trees per span. Spans without trees were also counted giving a result representative of the total number of trees managed in the urban area.	methodology is representative and provides reasonable accuracy. Other photographic data sources such as NDVI and NVIS do not lend themselves to accurately estimating numbers of trees per maintenance span.
DOEF0209	The Vegetation Management System (**VMS**) does not record the number of trees actually requiring maintenance. The VMS records the number of maintenance spans but not the number of trees per maintenance span. Therefore JEN provided an estimate for this information.	Average number of trees obtained from a physical survey of 100 rural spans conducted in Jan 2014.	Based on local knowledge the spans selected for survey were assumed to be representative of all rural maintenance spans. It is assumed that Jan 2014 survey results are valid for at least one cycle. If a tree was likely to require pruning within the next 5 years it was counted as a tree in that span. Locations for the survey were chosen on experience so as not to overstate or understate the average number of trees per span.	The estimate is JEN's best estimate because the methodology is representative and provides reasonable accuracy. Other photographic data sources such as NDVI and NVIS do not lend themselves to accurately estimating numbers of trees per maintenance span.
DOEF0213	JEN has estimated this information because this variable is not recorded in the	The estimate is made based on local knowledge and relevant safety legislation e.g. CFA Act which states that petrol	To arrive at a number which is the most realistic, the following assumptions were made:	JEN considers this to be its best estimate as the basis of the estimate is robust, and

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	GIS as a characteristic against each pole.	powered vehicles are not to be driven where their exhaust systems may contact vegetation such as grass, during the declared fire danger period (approximately 6 months in any 12 month period). Methodology used is as follows: 1. An average HV and ST span in the rural area is calculated based on the total length of HV and ST conductor length and the number of all poles supporting these conductors in this area. Some poles may be counted twice in order to estimate a realistic span length. 2. The GIS is used to find all poles located on private property in rural areas. These poles are filtered such that only poles supporting HV or ST are counted and each pole is only counted once. 3. The inaccessible line length is calculated by multiplying item 1 and 2 above. 4. The accessible line length is calculated by subtracting item 3 above from the total JEN circuit length for all voltages. It was identified (23 Feb 2015) that when variable code DOEF0301 – Route Line length was corrected in mid-2014 (to include route line length of the JEN underground network) dependent variable codes were missed in the correction. These are variables DOEF0101 –	1. All poles in the urban areas can be accessed by standard vehicles, therefore poles/lines in rural areas only are considered for this variable. 2. All poles supporting LV in the rural areas are accessible by standard vehicles. 3. All private poles in the rural areas are accessible by standard vehicles. 4. Only JEN owned poles need to be accessed. 5. All poles not accessible by standard vehicle are accessible in a straight line along the span. 6. Due to the weight of equipment being carried this estimate does not apply to asset inspection and work crew vehicles. 7. A standard vehicle is reference to a two wheel drive sedan/hatch type vehicle predominantly for the use by office based staff for auditing, scoping, event investigation or similar purposes. 8. Only poles supporting HV or ST lines which are not on a road reserve are inaccessible by standard vehicle due to the designed route of these lines. Note: A subset of the data output from the route line length query is used to calculate the standard vehicle access	furthermore, the JEN area is relatively flat and most poles are accessible within 10km on foot from the nearest road or path accessible by standard vehicle. The use of non-standard vehicles allows for better and timelier information capture for auditing or job scoping purposes. Whilst some LV only poles are inaccessible by standard vehicles the majority are in relative close proximity to dwellings (assumed to be accessible by standard vehicle). Conversely poles supporting HV lines were generally designed to take the shortest route and most do not have defined paths leading to or near them. It is JEN's experience that none of these poles are accessible in a straight line from pole to pole but because the location and length of paths (route to the pole) is not recorded and not wishing to overstate the distance to a pole (only the portion inaccessible to a standard vehicle) JEN chose

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Customer density and, DOEF0213 – Standard vehicle access. Refer to Table 8.2.1, directly below, for the Corrected back-cast data for variable code DOEF0213 – Standard vehicle access (Provided in 2015 submission). Refer to Table 8.2.2, directly below for the corrected representation of variable code DOEF0213 – Standard vehicle access. This table now correctly represents the variable as defined in the RIN.	route length. When calculating the 2014 value for standard vehicle access (DOEF0301) an error was identified in the Route Line Length query. The query was corrected for the calculation of the 2014 value. The 2014 value was used to recalculate the standard vehicle access values for 2013 and prior years, Table 8.2.2 below presents the variable based on 2014 data which accounts for the JEN route line length in other DNSP's areas not accessible by standard vehicles.	to represent 100% of the distance between poles off road.

90.

91. Table 8.2.1 Corrected back-cast data for variable code DOEF0213 – Standard vehicle access (Provided in 2015 submission)

	Unit	2009	2010	2011	2012	2013
Standard vehicle access (previously submitted)	km	3115.55	3114.78	3123.11	3121.99	3109.98
Standard vehicle access (corrected)	km	4087.12	4115.50	4162.65	4204.27	4224.98

92. Table 8.2.2 Corrected back-cast data for variable code DOEF0213 – Standard vehicle access (Provided in June 2015 based on AER questions)

	Unit	2009	2010	2011	2012	2013
Standard vehicle access (previously submitted)	km	124.71	125.77	126.19	124.74	124.60

3.7.3 SERVICE AREA FACTORS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
DOEF0301	JEN considers this variable to be actual information as the information was sourced from GIS.	A program was written to determine the route line length at the end of 2014. The number provided here includes the route line length of the JEN above ground and underground network. Same as for the overhead lines a program was written in the GIS to extract the route length of underground cables. For overhead conductor the program looks for multiple lines between poles and only counts this distance once. For underground cables, each cable is divided into 1m lengths and if a 1m segment from another cable is within 3m of any other segment then only one segment is counted. Route Line length was corrected in mid-2014 (to include route line length of the JEN underground network). Refer to Table 8.3.1, directly below, for the Corrected back-cast data for variable code DOEF0301 – Route line length. Note: When calculating the 2014 value for standard vehicle access (DOEF0301) an error was identified in the Route Line Length query. The query was corrected for the calculation of the	Service lines are not included.

Variable	Source and why actual	Methodology	Assumptions
		2014 value. The 2014 value was used to recalculate (back cast) the route line length values for 2013 and prior years, Table 8.3.2 below presents the variable based on 2014 data which accounts for the JEN route line length in other DNSP's areas.	

93. Table 8.3.1 Corrected back-cast data for variable code DOEF0301 – Route Line Length

	Unit	2006	2007	2008	2009	2010	2011	2012	2013
Route Line length (previously submitted)	km	3198	3204	3223	3231	3231	3240	3238	3225
Route Line length (corrected)	km	4062	4096	4163	4203	4232	4280	4320	4340

94. Table 8.3.2 Corrected (June 2015) back-cast data for variable code DOEF0301 – Route Line Length

	Unit	2006	2007	2008	2009	2010	2011	2012	2013
Route Line length	km	4165.46	4201.54	4271.30	4312.77	4343.76	4393.66	4436.14	4458.22

Estimated Information

95. No estimated information is provided.

3.7.4 WEATHER STATIONS

Actual Information

Variable	Source and why actual	Methodology	Assumptions
Weather stations	The source of the information for the Weather Stations was the Bureau of Meteorology (**BOM**). The data was sourced in early 2015 and is considered to be accurate. JEN considers this weather information to be actual information. Note: although the weather station details are actual data, the data that these provide (e.g. rainfall) are estimates. For instance, a rain gauge at a weather station measures how much rain is collected for that gauge. Although an actual measure for that gauge, it is an estimate of how much rain fell in a particular area or post code.	Weather stations that are located within the JEN territory have been included in this section.	The assumption that has been made is that the details of the weather stations that have been sourced from the BOM are accurate and up to date. Weather stations that were provided by the BOM and are outside the JEN territory have been excluded as they are not considered to be relevant to the management of the JEN network. Weather stations that have not recorded any weather data since May 2014 are not considered operational and therefore are unable to provide data that is relevant to the management of the JEN network.

Estimated Information

96. No estimated information is provided.

4. ATTACHMENT 1

97. See attached Microsoft Excel spreadsheet titled: ***JEN – EBT allocation model – FINAL – 30 Apr 14 – AER***