2017 RIN

Basis of Preparation

Economic Benchmarking

Document No: 2017 [PAL] [EB] RIN BOP

Revision: 1.0

Overview

Powercor is required to prepare a Basis of Preparation document which must,

a) demonstrate how the information provided is consistent with the requirements of the Notice;

b) explain the source from which Powercor obtained the information provided;

c) explain the methodology Powercor applied to provide the required information, including any assumptions Powercor made;

d) advise if the information is actual or estimate;

e) explain circumstances where Powercor cannot provide input for a variable using actual information, and therefore must provide estimated information:

    i. why an estimate was required, including why it was not possible for Powercor to use actual information;

    ii. the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is Powercor's best estimate, given the information sought in the Notice.

In accordance with the requirements above, this document provides details to support the information provided by Powercor in the Microsoft Excel workbooks titled:

- 2017 [PAL] [EB] RIN Template Export - Actual
- 2017 [PAL] [EB] RIN Template Export - Estimated
- 2017 [PAL] [EB] RIN Template Export - Consolidated

To satisfy the requirements of the *Notice*, the following information has been provided for each RIN table:

- classification of actual or estimated information;
- if estimated, appropriate justification provided;
- data source;
- methodology and assumptions adopted to prepare the information;
- any additional comments to support the basis of preparation.

Where estimates have been provided, Powercor is currently considering the feasibility of improvement opportunities to allow actual information to be provided in the future.

BOP ID	Tab ID	Tab Name	Table and Rule Allocation	Estimated / Actual	Data Source	Why Estimated?	Methodology	Assumptions	Additional Comments
BMPAL3.1BOP1	3.1	Revenue	TABLE 3.1.1 - REVENUE GROUPING BY CHARGEABLE QUANTITY Revenue from Fixed Customer Charges [Standard Control Services] Revenue from Energy Delivery charges where time of use is not a determinant [Standard Control Services] Revenue from On-Peak Energy Delivery charges [Standard Control Services] Revenue from Shoulder period Energy Delivery Charges [Standard Control Services] Revenue from Off-Peak Energy Delivery charges [Standard Control Services] Revenue from controlled load customer charges [Standard Control Services] Revenue from unmetered supplies [Standard Control Services] Revenue from Contracted Maximum Demand charges [Standard Control Services] Revenue from Measured Maximum Demand charges [Standard Control Services] Revenue from metering charges [Standard Control Services] Revenue from connection charges [Standard Control Services] Revenue from public lighting charges [Standard Control Services] Revenue from other Sources [Standard Control Services] Total revenue by chargeable quantity [Standard Control Services] TABLE 3.1.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS Revenue from residential Customers [Standard Control Services] Revenue from Non residential customers not on demand tariffs [Standard Control Services] Revenue from Non-residential low voltage demand tariff customers [Standard Control Services] Revenue from Non-residential high voltage demand tariff customers [Standard Control Services] Revenue from unmetered supplies [Standard Control Services] Revenue from Other Customers [Standard Control Services] Total revenue by customer class [Standard Control Services]	Actual	Revenue data was sourced from the SAS AHNP_O9500 billing table. This SAS table mirrors actual billing data from CIS Open Vision (CISOV).	N/A	Billing data was obtained from the SAS AHNP_O9500 billing table. As billing is based off actual NUOS the distribution revenue must then be recalculated using DUOS tariffs. Unmetered revenue is based on revenue collected for the network specific Unmetered tariff and the general purpose 'Unmetered' classification.	N/A	N/A
BMPAL3.1BOP2	3.1	Revenue	TABLE 3.1.1 - REVENUE GROUPING BY CHARGEABLE QUANTITY Revenue from Fixed Customer Charges [Alternative Control Services] Revenue from Energy Delivery charges where time of use is not a determinant [Alternative Control Services] Revenue from On-Peak Energy Delivery charges [Alternative Control Services] Revenue from Shoulder period Energy Delivery Charges [Alternative Control Services]	Actual	Alternative Control Services revenue is derived from the annual regulatory reports which are originally sourced from SAP.	N/A	When retailers/customers request work to be done for Alternative Control Services activities a charge is created in either CIS-OV or SAP. These charges are then allocated to a range of specific general ledger accounts dedicated to collecting Alternative Control Services revenue to facilitate reporting in the Statutory Accounts and Regulatory Accounts/Regulatory Information Notice.	Totals for ACS	N/A

			Revenue from Off-Peak Energy Delivery charges [Alternative Control Services] Revenue from controlled load customer charges [Alternative Control Services] Revenue from unmetered supplies [Alternative Control Services] Revenue from Contracted Maximum Demand charges [Alternative Control Services] Revenue from Measured Maximum Demand charges [Alternative Control Services] Revenue from metering charges [Alternative Control Services] Revenue from connection charges [Alternative Control Services] Revenue from public lighting charges [Alternative Control Services] Revenue from other Sources [Alternative Control Services] Total revenue by chargeable quantity [Alternative Control Services]						
BMPAL3.1BOP3	3.1	Revenue	TABLE 3.1.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS Revenue from residential Customers [Alternative Control Services] Revenue from Non residential customers not on demand tariffs [Alternative Control Services] Revenue from Non-residential low voltage demand tariff customers [Alternative Control Services] Revenue from Non-residential high voltage demand tariff customers [Alternative Control Services] Revenue from unmetered supplies [Alternative Control Services] Revenue from Other Customers [Alternative Control Services] Total revenue by customer class [Alternative Control Services]	Actual	Alternative Control Services revenue is derived from the annual regulatory reports which are originally sourced from SAP.	N/A	When retailers/customers request work to be done for Alternative Control Services activities a charge is created in either CIS-OV or SAP. These charges are then allocated to a range of specific general ledger accounts dedicated to collecting Alternative Control Services revenue to facilitate reporting in the Statutory Accounts and Regulatory Accounts/Regulatory Information Notice.	N/A	N/A
BMPAL3.1BOP4	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES EBSS [Standard Control Services] EBSS [Alternative Control Services]	Estimate	EBSS revenue is derived from a calculation with the following inputs and their sources: - 2016-20 EBSS allowances sourced from the AER 2016-20 determination post tax revenue model (PTRM) published on the AER website - Inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI; Australia	EBSS revenue is one of the building blocks used to calculate distribution tariffs. Revenue from each component of distribution tariffs is not reported in the business systems. Therefore EBSS revenue must be derived.	EBSS revenue allowances are set out in final determinations, smoothed over the relevant regulatory period. The smoothed revenue profile over the regulatory period recovers the NPV of the total revenue requirement (before smoothing) over the regulatory period. Therefore, each revenue requirement, including EBSS is smoothed over the regulatory period.	N/A	Essential Services Commission of Victoria (ESCV) efficiency carryover scheme revenues are also reported since the efficiency carryover scheme is the equivalent of the EBSS scheme. EBSS revenues are reported in the year the incentive has an impact on revenue rather the year of expenditure performance. Additionally, the EBSS carry over amounts have been smoothed over each regulatory period because prices were smoothed over regulatory periods. The requirements of the Notice have been met.
BMPAL3.1BOP5	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES STPIS [Standard Control Services] STPIS [Alternative Control Services]	Estimate	STPIS revenue is derived from a calculation with the following inputs and their sources: S factors for 2016 onwards are sourced from the AER approved annual pricing proposals, inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI;	STPIS revenue is one component of distribution revenue. Each component of distribution revenue is not reported in the	STPIS is calculated as the product of the s-factor and adjusted annual smoothed revenue published in the AER approved annual pricing proposal	N/A	STPIS revenues are reported in the year the incentive has an impact on revenue rather the year of service performance. The requirements of the Notice have been met.

					Australia	business systems.			
BMPAL3.1BOP6	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES F-Factor [Standard Control Services] F-Factor [Alternative Control Services]	Actual	F Factor revenue is derived from the AER approved annual pricing proposal models, which is the source for this revenue.	N/A	F Factor revenue is derived from the AER approved annual pricing proposal models. Powercor is either rewarded or penalised for performing better or worse than their respective fire start targets.	N/A	Powercor submits the Fire Factor (F-Factor) RIN to the Australian Energy Regulator (AER) on an annual basis; the AER then approves the F-Factor revenue in the Powercor annual tariff proposals. The requirements of the Notice have been met as Table 3.1.3 reflects the effect on revenues of the F-Factor incentive scheme in the year that the penalty or reward is applied.
BMPAL3.1BOP7	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES S-Factor True up [Standard Control Services] S-Factor True up [Alternative Control Services]	Estimate	2016-20 S factor close out revenue sourced from AER 2016-20 determination PTRM published on the AER website. WACC for 2016-20 sourced from AER 2016-20 determination PTRM published on the AER website. Inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI, Australia.	Each component of distribution revenue is not reported in the business systems. S factor close out revenue earned must therefore be derived.	S factor close out revenue is set out in the AER 2016-20 determination PTRM published on the AER website. Due to the smoothing in the PTRM of annual required revenue, the S factor close out revenue is smoothed over the regulatory period, along with the other building blocks.	N/A	The final true up for the Essential Services Commission of Victoria (ESCV) S Factor was included in the revenue allowance over 2016-20. The requirements of the Notice have been met.
BMPAL3.2BOP1	3.2	Operating Expenditure	TABLE 3.2.1 Current opex categories and cost allocations	Actual	The data for the current opex categories and cost allocations has been sourced from the SAP accounting system. SAP is the primary financial reporting system and is the source of providing the audited statutory accounts for Powercor.	N/A	The SAP financial system is used to extract the information required to state the DNSP opex information by category and regulatory segment. Using the audited statutory accounts for Powercor, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology. Information presented in this table utilises the cost allocation methodology applicable for the most recent, year and presents the data in alignment with the current opex categories.	N/A	Opex has been reported consistent with the cost allocation methodology, Regulatory Financial Statements and current opex categories for the most recent year.
BMPAL3.2BOP2	3.2	Operating Expenditure	TABLE 3.2.2 - Opex consistency - current cost allocation approach Opex for network services [Standard Control Services] Opex for network services [Alternative Control Services]	Estimated	The data for the current opex categories and cost allocations has been sourced from the SAP accounting system. SAP is the primary financial reporting system and is the source of providing the audited statutory accounts for Powercor. The data has been allocated between categories of distribution service in accordance with the cost allocation methodology that applied in the relevant regulatory year.	An estimate is required for opex for network services as this is a product of standard control total opex less the estimated amount calculated as opex for transmission connection point planning. As this estimated amount is deducted from the actual standard control opex, this therefore makes opex for network services an estimate. For the reasons why an estimate was required, relating to transmission connection point	The SAP financial system is used to extract the information required to state the DNSP opex information by category and regulatory segment. Using the audited statutory accounts for Powercor, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology. Information presented in this table utilises the cost allocation methodology that applied in the relevant regulatory year. Opex for network services is the total of standard control total opex less the amount reported as opex for transmission connection point planning. The amount deducted for transmission connection point planning is an estimation. For the methodology and assumptions relating to transmission connection point planning please refer to: DOPEX0206 - Opex for transmission connection point planning.	N/A	Opex has been reported consistent with the cost allocation methodology, Regulatory Financial Statements and opex categories in place at the time for those regulatory years, with the exception of the 2011 and 2012 years. Powercor's approved CAM for 2011 and 2012 was inconsistent with the AER's final distribution determination 2011- 15 service classification. In December 2013 the AER approved an amended CAM which is consistent with the AER's final distribution determination 2011-15 service classification. For the purposes of this RIN, Powercor has deemed that the 2011 and 2012 Regulatory Accounting Statements restated to be consistent with the approved amended CAM are the relevant Regulatory Accounting Statements. On this basis, opex has been reported consistent with the cost allocation methodologies, Regulatory Financial Statements and opex categories that applied in the relevant year.

						planning, please refer to: DOPEX0206A - Opex for transmission connection point planning			
BMPAL3.2BOP3	3.2	Operating Expenditure	TABLE 3.2.2 - Opex consistency - current cost allocation approach Opex for metering [Standard Control Services] Opex for metering [Alternative Control Services] Opex for connection services [Standard Control Services] Opex for connection services [Alternative Control Services] Opex for public lighting [Standard Control Services] Opex for public lighting [Alternative Control Services] Opex for amounts payable for easement levy or similar direct charges on DNSP [Standard Control Services] Opex for amounts payable for easement levy or similar direct charges on DNSP [Alternative Control Services]	Actual	The data for the current opex categories and cost allocations has been sourced from the SAP accounting system. SAP is the primary financial reporting system and is the source of providing the audited statutory accounts for Powercor. The data has been allocated between categories of distribution service in accordance with the cost allocation methodology that applied in the relevant regulatory year.	N/A	The SAP financial system is used to extract the information required to state the DNSP opex information by category and regulatory segment. Using the audited statutory accounts for Powercor, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology. Information presented in this table utilises the cost allocation methodology that applied in the relevant regulatory year. Information has been reported as applicable to the categories listed and is a subset of total opex. Opex for connection services has been derived by applying connections RAB as a percentage of total SCS RAB as per Table 3.3 over the current year's maintenance expenditure.	N/A	Powercor's approved CAM for 2011 and 2012 was inconsistent with the AER's final distribution determination 2011-15 service classification. In December 2013 the AER approved an amended CAM which is consistent with the AER's final distribution determination 2011-15 service classification. For the purposes of this RIN, Powercor has deemed that the 2011 and 2012 Regulatory Accounting Statements restated to be consistent with the approved amended CAM are the relevant Regulatory Accounting Statements. On this basis, opex has been reported consistent with the cost allocation methodology and Regulatory Financial Statements that applied in the relevant regulatory year. Information has been reported as applicable to the categories listed and is a subset of total opex.
BMPAL3.2BOP4	3.2	Operating Expenditure	TABLE 3.2.2 - Opex consistency - current cost allocation approach Opex for transmission connection point planning [Standard Control Services] Opex for transmission connection point planning [Alternative Control Services]	Estimated	DOPEX0206A - Opex for transmission connection point planning The costs are prepared in an internal spreadsheet which is a summation of the following categories: - The number of Terminal Stations, sourced from the annual Transmission Connection Planning Report (TCPR) - percentage of average FTE's time spent per Connection Point on demand forecasting and directing augmentations, sourced from management judgement - Regulatory Test Report Legal Costs sourced from the SAP system - External consultant costs for the TCPR (Transmission Connection Planning Report) development were sourced from a combination of SAP and using management judgement - Regulatory Test Report related work was sourced from a combination of SAP and management judgment. - Planning Permit, Tender documents, Use of System Agreement, Exit Services Agreement costs and share of funding from AEMO for Deer Park terminal station were sourced from actual invoices and the SAP system.	A. Internal FTE costs for forecasting and directing augmentations: Basis used was management judgment to determine that each terminal station required 15% of the annual time of one engineering FTE, and each engineering FTE was estimated to be on a salary of $127.3k per year. B. The annual Consultant fee is an estimate based on management judgment of an approximate hourly rate charged by external consultants by the number of hours to complete the required reports. C. Internal FTE costs for preparing internal reports.	The methodology used employed as much actual information as possible, and estimations where actual information was not available. 2017 is a summation of the categories listed in section C, and the methodology consists of - The total internal FTE costs were based on the proportion of an FTE spent on each terminal station per year. The number of terminal station connections was an actual figure. - Legal costs for general Use of System Agreement (UoSA) negotiations were actual costs from invoices from external legal providers - Consultant fees for, Transmission Connection Planning Report (TCPR) Development were sourced from actual cost invoices. - The total internal FTE costs for preparing internal regulatory test reports and attending joint planning sessions with other distribution businesses were based on the proportion of time spent on these activities. - External consultants costs for published Regulatory Test Reports were actual costs from invoices.	N/A	In relation to the opex related to transmission connection planning, there has been no material change in the current opex cost allocation process.
BMPAL3.2BOP5	3.2	Operating Expenditure	TABLE 3.2.4 - OPEX FOR HIGH VOLTAGE CUSTOMERS	Estimated	PAL must report the amount of Opex that it would have incurred had it	Where complete data could not be	(i) Establish distribution transformer capacity owned by utility sourced from Network Planning (DPA0501)	N/A	The response to the requirement DOPEX0401 is shown as estimated as

			Opex for high voltage customers [End user costs (not standard control services)]		been responsible for operating and maintaining the electricity distribution transformers that are owned by its high voltage customers. - CPI data - sourced from finance group. - Maintenance costs - sourced from Function Code 350 and Function Code 318 expenditure as reported from BI. Definition of function codes as per Function Code Definitions Manual Document No 10-40-M0001. - Distribution transformer capacity owned by utility - sourced from Network Planning - also reported as DPA0501. - Distribution transformer capacity owned by High Voltage Customers - sourced from Network Planning - also reported as DPA0502.	retrieved using the (Load Profile Report Launcher) as above, retrieval of data using SAP Hana was attempted. Where data was missing from a year which could not be retrieved by SAP Hana (a database query tool), an estimate has been provided. This data is estimated as: - HV customer capacity is not controlled by Powercor and inherently is estimated by applying the average % of total network MD using those years for which complete data is available.	annual planning reports. (MVA) (ii) Establish total Distribution Substation Maintenance Opex from expenditure reports for Function Codes 350 and 318. (EN Distribution substation maintenance) ($k). Cost reports reviewed and costs not applicable to distribution substation maintenance removed. (iii) Calculate a nominal unit rate for Network Distribution Substation maintenance by dividing total MVA by total Opex to arrive at ($/MVA) (iv) Calculate a real unit rate by applying CPI to the rate calculate previously for years prior (v) Average the real unit rates and set current year as the average, ($/MVA) (vi) Apply CPI to the average unit rate for years prior, ($/MVA) (vii) Establish Distribution transformer capacity owned by High Voltage Customers sourced from Network Planning (DPA0502) annual planning reports. (MVA) Calculate HV Customer Opex for each year by multiplying Average unit rate by the Sum of the HV Customer Capacity, ($/MVA).		Powercor, by definition, cannot have actual data for costs it would have incurred if it had operating and maintenance responsibility for distribution transformers owned by HV customers. The estimation of DOPEX0401 has been carried out in accordance with the Requirements of the Notice instructions as above. 'PAL must report the amount of Opex that it would have incurred had it been responsible for operating and maintaining the electricity distribution transformers that are owned by its high voltage customers' As such for reporting purposes, CP/PAL has estimated the opex which would otherwise have been expensed, had the company been responsible for their maintenance. Change in trend due to the HVC Capacity (MVA)- DPA0502 data provided by the planning group was incorrect over past years the years. So that is the reason there is a change in trend.
BMPAL3.2.3BOP1	3.2.3	Provisions	TABLE 3.2.3 - PROVISIONS	Actual	The data for provisions has been sourced from the SAP accounting system. SAP is the primary financial reporting system and is the source of providing the audited statutory accounts for Powercor.	N/A	The SAP financial system is used to extract the information required to state the DNSP provision information. Using the audited statutory accounts for Powercor, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning provisions to the applicable capex and opex regulatory segments. Data contained in these tables is consistent with the data reported within the Historical Annual RINs. As the provisions are attached to employees and not to capital and operating activities, employee entitlement provisions are allocated between capital and operating costs using labour reported in the annual Regulatory Accounting Statements (Labour Cost Matrix template) as the allocator. The Long Service Leave Bond adjustment is allocated solely to opex and the remainder of the movement is split between opex and capex using this assumption.	N/A	Provisions have been reported consistent with that of the Regulatory Financial Statements for each regulatory year.
BMPAL3.3BOP1	3.3	Assets (RAB)	TABLE 3.3.1 - REGULATORY ASSET BASE VALUES	Estimated	RIN data within tab	Source data is estimated	The data in this table is the sum of the RAB variables in Table 3.3.2.	N/A	N/A
BMPAL3.3BOP2	3.3	Assets (RAB)	TABLE 3.3.2 - ASSET VALUE ROLL FORWARD	Estimated	- RIN data within this tab - CPI from ABS table 6401.0 - Forecast depreciation from 2016-20 Final Determination PTRM - WACC from AER SCS PTRM updated for 2017 debt rate - Asset value data from 2013	The benchmarking RIN requires allocation into specific asset categories using specific AER methodology. This information is not available from existing business systems and data.	The RAB for Standard Control Services has been rolled forward using the AER roll forward model template and data from the sources listed. The allocation of regulatory asset categories to the required AER asset categories is based on the replacement cost methodology used in the 2013 Benchmarking RIN. This applies to the following regulatory asset categories: subtransmission, distribution system assets, VBRC, supervisory cables and old SWER ACRs. Other regulatory asset categories are allocated to the required AER asset categories either directly (eg. metering) or based on asset life.	N/A	This BOP covers data in the 'Standard Control Services' column.

							Disposals are taken as the cash proceeds from sale of assets as reported in the cash flow section of annual RIN.		
BMPAL3.3BOP3	3.3	Assets (RAB)	TABLE 3.3.2 - ASSET VALUE ROLL FORWARD	Estimated	- RIN data within tab - Estimated gross Dedicated Assets/Gross Connection capex ratio	As per AER requirements.	The Network Services RAB has been estimated. An estimate of gross dedicated capex to gross new customer connection capex is used to estimate the proportion of net dedicated assets capex to net network capex. This ratio (averaged over 5 years) is used to estimate the connection services portion of the RAB which is deducted from SCS network RAB to derive the estimated Network Services RAB.	N/A	This BOP covers data in the 'Network Services' column.
BMPAL3.3BOP4	3.3	Assets (RAB)	TABLE 3.3.3 - TOTAL DISAGGREGATED RAB ASSET VALUES	Estimated	RIN data within tab	Source data is estimated.	Total disaggregated RAB asset values have been calculated as the average of the opening and closing RAB values for each category. The capex reported in this tab is net capex and only net capex is rolled into the RAB, therefore capital contributions are not reported here.	N/A	N/A
BMPAL3.3BOP5	3.3	Assets (RAB)	TABLE 3.3.4 - ASSET LIVES ESTIMATED SERVICE LIFE OF NEW ASSETS	Estimated	- 2016-20 Final Determination PTRM (Standard Control Services) - 2016-20 Final Determination PTRM (Metering) - 2016-20 Final Determination Public Lighting model - RIN data within tab	As per AER requirements.	The asset lives are taken from the 2016-20 Final Determination models and the weighted average calculated for each of the required AER asset categories.	N/A	The business has used AER's standard approach.
BMPAL3.3BOP6	3.3	Assets (RAB)	TABLE 3.3.4 - ASSET LIVES ESTIMATED RESIDUAL SERVICE LIFE	Estimated	RIN data within tab	As per AER requirements.	Remaining lives for all asset categories are calculated as the ratio of opening RAB to straight line depreciation.	N/A	N/A
BMPAL3.3BOP7	3.3	Assets (RAB)	TABLE 3.3.2 - ASSET VALUE ROLL FORWARD	Estimated	- Annual RIN data - CPI from ABS table 6401.0 - WACC from AER Metering PTRM updated for 2017 debt rate	N/A	The Metering RAB has been rolled forward using the AER roll forward model template and the data sources listed. The Public Lighting RAB has been rolled forward using the Final Determination Public Lighting model and the data sources listed. Capex for 'Energy Efficient' public lighting capex was taken directly from the Annual RIN. Capex for 'Non-Energy Efficient' public lighting has been allocated to 'Poles and brackets' and 'Existing Lights' based on the weightings of these in 2014. The capital expenditure includes public lighting replacements which do not incur customer contributions.	N/A	This BOP covers data in the 'Alternative Control Services' column. The business has used the AER's standard approach provided under Economic Benchmarking RIN for distribution network service providers - Instructions and Definitions.
BMPAL3.4BOP1	3.4	Operational Data	TABLE 3.4.1 - ENERGY DELIVERY Total energy delivered [Standard Control Services] Energy Delivery where time of use is not a determinant [Standard Control Services] Energy Delivery at On-peak times [Standard Control Services] Energy Delivery at Shoulder times [Standard Control Services] Energy Delivery at Off-peak times [Standard Control Services] Controlled load energy deliveries [Standard Control Services] Energy Delivery to unmetered supplies [Standard Control Services] Residential customers energy deliveries	Actual	Energy volume data was sourced from the SAS AHNP_O9500 billing table. This table includes volumes as well as billed amounts. This SAS table mirrors actual billing data from CIS Open Vision (CISOV).	N/A	Energy Volumes are based on billed volumes only relating to the year under review. Billing relating to other periods was excluded. Quantities were obtained by dividing revenue by the published NUOS price for each tariff. This approach accounts for pro-rating where customers may have only been billed for part of a month. Unmetered was addressed separately and a 60%/40% peak/off peak split was assumed. Volumes were back-solved using known billings and published tariffs to determine quantities.	N/A	3.4 - Data obtained for this table was obtained from billed energy volumes, accruals and any billing adjustments for that given year. Billed energy volumes, accruals and billing adjustments is calculated at site (NMI) level and aggregated as a total. 3.4.1.1 - As per the definitions under 'Charges' in chapter 9 of the Economic benchmarking RIN for DNSP, data recorded in this table is aggregated by tariff and reported in the benchmarking RIN by the definitions provided. Energy volumes reported under single rate tariffs was used to populate DOPED0201 where 'Energy Delivery where time of use is not a determinant'.

			[Standard Control Services] Non residential customers not on demand tariffs energy deliveries [Standard Control Services] Non-residential low voltage demand tariff customers energy deliveries [Standard Control Services] Non-residential high voltage demand tariff customers energy deliveries [Standard Control Services] Other Customer Class Energy Deliveries [Standard Control Services]						3.4.1.4 - As per the definitions under 'Customer Types' in chapter 9 of the Economic benchmarking RIN for DNSP, data recorded in this table is aggregated based on the definitions provided.
BMPAL3.4BOP2	3.4	Operational Data	TABLE 3.4.1 - ENERGY DELIVERY Energy into DNSP network at On-peak times [Standard Control Services] Energy into DNSP network at Shoulder times [Standard Control Services] Energy into DNSP network at Off-peak times [Standard Control Services] Energy received from TNSP and other DNSPs not included in the above categories [Standard Control Services]	Actual	The data has been sourced from the Itron Enterprise Edition (IEE) revenue metering system (in some cases via the SAP HANA reporting tools). The IEE system contains all metering data for all meters from 2006 onwards. It has replaced metering systems previously used as the source of data in reporting energy figures. There may be differences in metering figures for past years compared to previously reported, however this will not relate to the change in the system, it relates to the fact that metering data can be revised from time to time and the current figures reflect the latest revisions. The data that comes from IEE system contains interval data from 3rd party meters that are located at the points of connection between the Powercor network and the TNSP/DNSP. All of the data from all parties in IEE is provided in line with the metering rules, which does allow for occasional estimating and substituting of values however this would make up a less than 1% of all readings.	N/A	Data was extracted from the Powercor IEE revenue metering system into MS Excel. A macro was then run to convert the interval data into Peak and Off Peak using the rule that Peak is 7am - 11pm on weekdays, and all other times are Off Peak. Shoulder times have not been considered in this modelling as it would create an inconsistency with the energy figures provided in DOPED0401 - DOPED0404 where it is not possible to perform that split.	N/A	Powercor has reported energy input into its network as measured at supply points from the TNSP and other DNSPs. Energy received from TNSP and other DNSP has been measured/calculated in accordance with the definitions of chapter 9, which is the amount of electricity transported out of Powercor's network in the relevant Regulatory Year (measured in GWh).
BMPAL3.4BOP3	3.4	Operational Data	TABLE 3.4.1 - ENERGY DELIVERY Energy into DNSP network at On-peak times from non-residential embedded generation [Standard Control Services] Energy into DNSP network at Shoulder times from non-residential embedded generation [Standard Control Services] Energy into DNSP network at Off-peak times from non-residential embedded generation [Standard Control Services] Energy received from embedded generation not included in above categories from non-residential embedded generation [Standard Control Services] Energy into DNSP network at On-peak times from residential embedded generation [Standard Control Services] Energy into DNSP network at Shoulder times from residential embedded generation [Standard Control Services] Energy into DNSP network at Off-peak times from residential embedded generation [Standard Control Services]	Actual	The data has been sourced from the Itron Enterprise Edition (IEE) revenue metering system (in some cases via the SAP HANA reporting tools). Data to break up customers into Residential and Non-Residential has come from CIS, where the flag Domestic has been used to assume a customer is Residential. All other customers have been treated as Non-Residential.	N/A	Generators from their interval data using Peak and Off Peak using the rule that Peak is 7am - 11pm on weekdays, and all other times are Off Peak.	N/A	Powercor has reported energy received from Non-residential and residential Embedded Generation by time of receipt. Energy received from embedded generators has been measured/calculated in accordance with the definitions of chapter 9, as meter data has been reported, for energy received.

			Energy received from embedded generation not included in above categories from residential embedded generation [Standard Control Services]						
BMPAL3.4BOP4	3.4	Operational Data	TABLE 3.4.2 - CUSTOMER NUMBERS Residential customer numbers [Standard Control Services] Non residential customers not on demand tariff customer numbers [Standard Control Services] Low voltage demand tariff customer numbers [Standard Control Services] High voltage demand tariff customer numbers [Standard Control Services] Unmetered Customer Numbers [Standard Control Services] Other Customer Numbers [Standard Control Services] Total customer numbers [Standard Control Services] Customers on CBD network [Standard Control Services] Customers on Urban network [Standard Control Services] Customers on Short rural network [Standard Control Services] Customers on Long rural network [Standard Control Services] Total customer numbers [Standard Control Services]	Actual	Total customer numbers are obtained from the billing system, CIS Open Vision.	N/A	Customer Numbers by customer type or class: The number of active (customer is not end-dated) NMIs per tariff is obtained from Powercor's end of month reporting. For de-energised sites, a count is obtained of the last tariff that applied to all other sites, excluding abolished (extinct) sites. The active and de-energised numbers are added together to give Total Customer numbers, which are aggregated by grouping tariffs in accordance with the reporting categories. An average of these numbers at the start and end of the Regulatory Year is used. CISOV is the original source of all data. Customer Numbers by location on the network: Calculated by weighting the Customer Numbers by customer type or class by split based on location. The proportions were calculated using GIS data in SAS with each NMI mapped to a feeder classified as either; CBD, Urban, Rural Long or Short.	N/A	3.4.2.1 - The customer numbers in this table is the count of energised and de-energised NMIs and categorised in accordance to the definitions stated under 'Customer Types' in chapter 9. 3.4.2.2 The numbers reported in this table is the count of energised and de-energised NMIs in accordance to the definitions stated in chapter 9.
BMPAL3.4BOP5	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services] Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services]	Actual	All zone substation raw peak demand source data is collected from Ion power quality meters, located at each individual zone substation. If Ion meter data is unavailable, then TrendScada data is used. Historically, Powercor does not record coincident peak demand at the zone substation level. Where information has been previously reported to regulatory bodies, Powercor has used this data for the benchmarking RIN. DOPSD0101 & DOPSD0201: Non-coincident summated Raw System Annual Maximum Demand - The source data was obtained from Powercor Ion meters or TrendScada meter data (where Ion meter data is unavailable) and customer HV metering data, at the time of the zone substation annual peak demand. DOPSD0104 & DOPSD0204: Coincident summated Raw System Annual Maximum Demand - The source data was obtained from Powercor Ion meters or TrendScada meter data (where Ion meter data is unavailable) and customer HV	N/A	Each year contains the summation of all Powercor Zone Substations and 66kV HV Customer Substation MW and MVA load at coincident and non-coincident peak demand.	N/A	The information provided in tables 3.4.3.1 and 3.4.3.3 is a summation of the maximum demand measured at the zone substation for the non-coincident level and a summation of the zone substation demand measured at the time of peak demand of the whole Powercor network (coincident). The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. Note: The raw (or unadjusted) non coincident maximum demand at the zone substation level was annually reported from 2006 to 2012 in the Distribution System Planning Report (DSPR) and from 2012 onwards in the Distribution Annual Planning Report (DAPR).

					metering data, at the time of the system annual peak demand.				
BMPAL3.4BOP6	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services]	Actual	All zone substation raw peak demand source data is collected from Ion power quality meters, located at each individual zone substation. If Ion meter data is unavailable, then TrendScada data is used. Historically, Powercor does not record coincident peak demand at the zone substation level. Where information has been previously reported to regulatory bodies, Powercor has used this data for the benchmarking RIN. DOPSD0101 & DOPSD0201: Non-coincident summated Raw System Annual Maximum Demand - The source data was obtained from Powercor Ion meters or TrendScada meter data (where Ion meter data is unavailable) and customer HV metering data, at the time of the zone substation annual peak demand. DOPSD0104 & DOPSD0204: Coincident summated Raw System Annual Maximum Demand - The source data was obtained from Powercor Ion meters or TrendScada meter data (where Ion meter data is unavailable) and customer HV metering data, at the time of the system annual peak demand. For variables DOPSD0102, DOPSD0103, DOPSD0105, DOPSD0106, DOPSD0202, DOPSD0203, DOPSD0205, DOPSD0206: Both Powercor and Customer substations were combined at the Raw system level, for both coincident and non-coincident MW and MVA. Coincident weather corrected figures were calculated using the ratio method mentioned in the methodology section of this BOP.	To provide a coincident weather adjusted value, the ratio of the weather adjusted and raw non coincident peak demand was used.	For variables DOPSD0105, DOPSD0106, DOPSD0205, DOPSD0206, the coincident weather adjusted peak demands were calculated using the ratios of the non-coincident weather adjusted peak demands: MW 10% POE (PAL subs Only) / RAW (PAL subs Only) =1.18225362183236 50% POE(PAL subs Only) / RAW (PAL subs Only)= 1.01461148193241 MVA 10% POE(PAL subs Only) / RAW (PAL subs Only) = 1.13922556133333 50% POE (PAL subs Only)/ RAW (PAL subs Only)= 1.01544722450015	N/A	Historically Powercor did not weather adjust its raw non coincident or coincident maximum demand at zone substation level, until it developed a POE calculator in 2010. All 'actual' data provided in the previous EDPR was raw maximum demand as defined in chapter 10 of the National Electricity Rules. To provide an estimate for the historical 10% and 50% POE weather adjusted data, Powercor used a ratio derived by the National Institute of Economic and Industry Research (NIEIR) and applied it to the summation of the non-coincident and coincident maximum demand at zone substation level. From 2011 to 2016, a summation of the weather adjusted non coincident maximum demand at the zone substation using Powercor's POE calculator. Powercor does not weather adjust coincident level zone substation demand, therefore as a best estimate, a ratio of the non-coincident weather adjusted maximum demand was used to calculate the coincident weather adjusted demand.
BMPAL3.4BOP7	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services] Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services]	Actual	All Terminal station raw peak demand source data is collected from the IEE wholesale meter data for each individual Terminal Station.	N/A	DOPSD0107 & DOPSD0207: Non-coincident summated raw system annual peak demand. The source data was obtained from the summation of the actual raw terminal station maximum demands for each year sourced from IEE database. DOPSD0110 & DOPSD0210: Coincident summated raw system annual peak demand The source data was obtained from the summation of the actual raw terminal station maximum demands at the date and time of system peak for each year and sourced from IEE database.	N/A	The information provided in the variable codes stated above in Tables 3.4.3.2 and 3.4.3.4 is a summation of the maximum demand measured at the transmission connection point for the non-coincident level and a summation of the transmission connection point demand measured at the time of peak demand of the whole Powercor network (coincident). The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. Note that the

							The source of the data is the IEE wholesale metering database accessed through a tool called SAP BW on HANA Production. This data is contained in a load estimate spreadsheet for each terminal station which contains historical actual data.		summated maximum demand at a transmission level usually occurs in summer. Seasonal summer is used for the purposes of the RIN, hence summer 2017 is considered between the months November 2016 to March 2017. The information provided is consistent with the requirements of the Notice.
BMPAL3.4BOP8	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services]	Estimated	All Terminal station raw peak demand source data is collected from the IEE whole sale meter data for each individual Terminal station.	Powercor does not weather adjust the coincident terminal station connection point maximum demands. To estimate the 10 and 50% POE coincident values, a ratio of the summated raw actual coincident terminal station maximum demands to summated raw actual non-coincident terminal station maximum demands was used as a multiplier with the summated non-coincident terminal station demand.	The POE is the probability that the actual weather circumstances will be such that the actual Maximum Demand experienced will exceed the relevant maximum demand measure adjusted for weather correction. A 50% Probability of Exceedance means that the Maximum Demand measure adjusted for weather correction is expected to be exceeded fifty out of every one hundred years. DOPSD0109 & DOPSD0209: Non-coincident summated weather adjusted system annual peak demand 50% POE - The source data was obtained from the summation of the weather adjusted 50% terminal station non-coincident maximum demands for each year sourced from various Powercor load estimate spreadsheets. An internal POE calculator was used to calculate these figures. DOPSD0108 & DOPSD0208: Non-coincident summated weather adjusted system annual peak demand 10% POE - The source data was obtained from summation of the weather adjusted 10 % terminal station non-coincident maximum demands for each year sourced from various Powercor load estimate spreadsheets. An internal POE calculator was used to calculate these figures. DOPSD0112 & DOPSD0212: Coincident summated weather adjusted system annual peak demand 50% POE - The data was derived from the coincident raw maximum demand data by utilising 50% POE/actual ratios provided by the National Institute of Economic and Industry Research (NIEIR) for the whole Powercor network load. DOPSD0111 & DOPSD0211: Coincident summated weather adjusted system annual peak demand 10% POE - The data was derived from the coincident raw maximum demand data by utilising 10% POE/actual ratios provided by the National Institute of Economic and Industry Research (NIEIR) for the whole Powercor network load. To estimate the 10 and 50% POE coincident values, a ratio of the summated raw actual coincident terminal station maximum demands to summated raw actual non-coincident terminal station maximum demands was used as a multiplier with the summated non-coincident terminal station demand.	N/A	The information provided in the variable codes stated above in Tables 3.4.3.2 and 3.4.3.4 is a summation of the calculated or derived weather adjusted maximum demand measured at the transmission connection point for the non-coincident level and a summation of calculated or derived weather adjusted maximum demand at the transmission connection point demand measured at the time of peak demand of the whole Powercor network (coincident). The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. The information provided is consistent with the requirements of the Notice. Where estimated historical weather adjusted data is provided, Powercor used a ratio derived by the National Institute of Economic and Industry Research (NIEIR) and applied it to the summation of the non-coincident and coincident maximum demand at the transmission connection point to provide the 10% POE (Probability of Exceedance) Level data.
BMPAL3.4BOP9	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Average overall network power factor conversion between MVA and MW [Standard Control Services] Average power factor conversion for low voltage distribution lines [Standard Control Services] Average power factor conversion for 3.3 kV lines [Standard Control Services]	Estimated	DOPSD301: Data used to calculate the power factor was sourced from DOPSD0110 and DOPSD0210. DOPSD302, DOPSD0306, DOPSD0307, DOPSD0308, DOPSD0311: The data used to populate the above sections was sourced from Table 2, of	The values defined in Table 2, of section 4.3 of the 'Electricity Distribution Code' version 7, May 2012, are standard reference values which are readily	DOPSD301: Overall network power factor is calculated by dividing the transmission connection point coincident Raw system annual maximum demand MW by the transmission connection point coincident Raw system annual maximum demand MVA. DOPSD302, DOPSD0306, DOPSD0307, DOPSD0308, DOPSD0311:	NA	Data used to calculate the average overall network power factor was sourced from the measured transmission connection point data in sections DOPSD0110 and DOPSD0210. As the data for the remaining voltage levels is not readily stored or available, as best engineering estimates, Powercor refers to

			Average power factor conversion for 6.6 kV lines [Standard Control Services] Average power factor conversion for 7.6 kV lines [Standard Control Services] Average power factor conversion for 11 kV lines [Standard Control Services] Average power factor conversion for SWER lines [Standard Control Services] Average power factor conversion for 22 kV lines [Standard Control Services] Average power factor conversion for 33 kV lines [Standard Control Services] Average power factor conversion for 44 kV lines [Standard Control Services] Average power factor conversion for 66 kV lines [Standard Control Services] Average power factor conversion for 110 kV lines [Standard Control Services] Average power factor conversion for 132 kV lines [Standard Control Services] Average power factor conversion for 220 kV lines [Standard Control Services]		section 4.3 of the 'Electricity Distribution Code' version 7, May 2012. The values used were for customer maximum demand over 2MVA, minimum lagging. DOPSD0303, DOPSD0304, DOPSD0305, DOPSD0309, DOPSD0310, DOPSD0312, DOPSD0313 and DOPSD0314: Powercor do not have these voltage lines and so are zero.	available for industry to use for any calculations where the power factor is required.	Values taken from Table 2, of section 4.3 of the 'Electricity Distribution Code'. The values used were for customer maximum demand over 2MVA, minimum lagging. This is the best engineering estimates as the data is not readily stored or available at these voltage levels.		the values defined in Table 2, of section 4.3 of the 'Electricity Distribution Code' version 7, May 2012. The values used were for customer maximum demand over 2MVA, minimum lagging.
BMPAL3.4BOP10	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Summated Chargeable Contracted Maximum Demand [Standard Control Services] Summated Chargeable Measured Maximum Demand [Standard Control Services] Summated Chargeable Contracted Maximum Demand [Standard Control Services] Summated Chargeable Measured Maximum Demand [Standard Control Services]	Actual	Similarly to the Energy Volumes data - summated demand was sourced from the SAS AHNP_O9500 billing table. This table includes volumes as well as billed amounts. This SAS table mirrors actual billing data from CIS Open Vision (CISOV).	N/A	Summated quantities are aggregated by month (in line with billing) and the maximum quantity recorded within a given year is populated in the benchmarking RIN.	N/A	Powercor's tariff structure charges demand on a unit of measure of kW. To comply with the definition of 'MW measure', the quantity is converted to MW. Customers are not charged on a MVA basis therefore the variable codes DOPSD0403 and DOPSD0404 have not been reported' to explain why these are zero.
BMPAL3.5BOP1	3.5	Physical Assets	TABLE 3.5.1 - NETWORK CAPACITIES Overhead low voltage distribution [Volume in KM's (0's)] (DPA0101) Overhead 2.2 kV [Volume in KM's (0's)] (DPA0102) Overhead 6.6kv [Volume in KM's (0's)] (DPA0103) Overhead 7.6 kV [Volume in KM's (0's)] (DPA0104) Overhead 11 kV [Volume in KM's (0's)] (DPA0105) Overhead SWER [Volume in KM's (0's)] (DPA0106) Overhead 22 kV [Volume in KM's (0's)] (DPA0107) Overhead 33 kV [Volume in KM's (0's)] (DPA0108) Overhead 44 kV [Volume in KM's (0's)] (DPA0109) Overhead 66 kV [Volume in KM's (0's)] (DPA0110) Overhead 110kV [Volume in KM's (0's)] (DPA0111) Overhead 132 kV [Volume in KM's (0's)] (DPA0112) Overhead 220kV [Volume in KM's (0's)] (DPA0113) Other [Volume in KM's (0's)] (DPA0114)	Actual	GIS is the originating data source. The data from GIS is made available to Powercor through a BI (Business Intelligence) report called the 'Asset Installation Report'.	N/A	The data was obtained utilising a GIS (Geographical Information System) query that traces the In-Service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note: - Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the criteria specified in this Information Notice - An overhead 22kV Subtransmission component was included as an additional line item for completeness - Overhead elements associated with communication, protection & control and unmetered loads were excluded In 2017 the data from GIS is made available through a BI (Business Intelligence) report called the 'Asset Installation Report'.	N/A	For the year 2017, the data was obtained utilising a GIS (Geographical Information System) query that traces the in - service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note: - Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the criteria specified in this Information Notice - An overhead 22kV Subtransmission component was included as an additional line item for completeness - Overhead elements associated with communication, protection & control and unmetered loads were excluded.
BMPAL3.5BOP2	3.5	Physical Assets	TABLE 3.5.1 - NETWORK CAPACITIES Underground low voltage distribution [Volume	Actual	GIS is the originating data source. The data from GIS is made available to	N/A	The data from GIS is made available to through a BI (Business Intelligence) report called the 'Asset	N/A	For the year 2017 the data was obtained utilising a GIS (Geographical Information

			in KM's (0's)] (DPA0201) Underground 5 kV [Volume in KM's (0's)] (DPA0202) Underground 6.6 Kv [Volume in KM's (0's)] (DPA0203) Underground 7.6 kV [Volume in KM's (0's)] (DPA0204) Underground 11 kV [Volume in KM's (0's)] (DPA0205) Underground SWER [Volume in KM's (0's)] (DPA0206) Underground 22 kV [Volume in KM's (0's)] (DPA0207) Underground 33 kV [Volume in KM's (0's)] (DPA0208) Underground 66 kV [Volume in KM's (0's)] (DPA0209) Underground 110 kV [Volume in KM's (0's)] (DPA0210) Underground 132 kV [Volume in KM's (0's)] (DPA0211) Other [Volume in KM's (0's)] (DPA0212)		Powercor through a BI (Business Intelligence) report called the 'Asset Installation Report'.		Installation Report'.		System) query that traces the in - service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note: - Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the criteria specified in this Information Notice An Underground 22kV Subtransmission component was included as an additional line item for completeness - Underground elements associated with communication, protection & control and unmetered loads were excluded.
BMPAL3.5BOP3	3.5	Physical Assets	TABLE 3.5.1 - NETWORK CAPACITIES Overhead low voltage distribution [Volume in MVA (0's)] (DPA0301) Overhead 6.6 kV [Volume in MVA (0's)] (DPA0302) Overhead 7.6 kV [Volume in MVA (0's)] (DPA0303) Overhead 11 kV [Volume in MVA (0's)] (DPA0304) Overhead SWER [Volume in MVA (0's)] (DPA0305) Overhead 22 kV [Volume in MVA (0's)] (DPA0306) Overhead 33 kV [Volume in MVA (0's)] (DPA0307) Overhead 44 kV [Volume in MVA (0's)] (DPA0308) Overhead 66 kV [Volume in MVA (0's)] (DPA0309) Overhead 110 kV [Volume in MVA (0's)] (DPA0310) Overhead 132 kV [Volume in MVA (0's)] (DPA0311) Overhead 220 kV [Volume in MVA (0's)] (DPA0312) Other [Volume in MVA (0's)] (DPA0313) Underground low voltage distribution [Volume in MVA (0's)] (DPA0401) Underground 5 kV [Volume in MVA (0's)] (DPA0402) Underground 6.6 kV [Volume in MVA (0's)] (DPA0403) Underground 7.6 kV [Volume in MVA (0's)] (DPA0404) Underground 11 kV [Volume in MVA (0's)] (DPA0405) Underground SWER [Volume in MVA (0's)] (DPA0406) Underground 12.7 kV [Volume in MVA (0's)] (DPA0407) Underground 22 kV [Volume in MVA (0's)]	Estimated	The data source for the estimated overhead and underground network weighted average MVA capacity come from estimates provided by the AER for the 66kV voltage and the network planning guidelines for all other voltages.	For the 66kV the estimation was provided by the AER, therefore applying this estimate ensures method calculation is in line with AER policy. For all other voltages, the network planning guidelines were used, as they are inline with how the network is operated.	The weighted average MVA capacity are estimates relating to the typical augmentation capacity constructed while allowing for planning policy. For example the 22 kV rating of 8MVA is the planning rating for new construction rated at 12MVA but allowing for transfers to adjacent feeders of 1/3 of capacity.	N/A	Powercor has provided estimated overhead and underground weighted average capacity based on network planning guidelines for typical ratings per voltage class. For the SWER network the capacity was based on the summated average capacity of the SWER isolation transformers. The estimated data is in accordance with the definitions in chapter 9.

			(DPA0408) Underground 33 kV [Volume in MVA (0's)] (DPA0409) Underground 66 kV [Volume in MVA (0's)] (DPA0410) Underground 110 kV [Volume in MVA (0's)] (DPA0411) Underground 132 kV [Volume in MVA (0's)] (DPA0412) Other [Volume in MVA (0's)] (DPA0413)						
BMPAL3.5BOP4	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Distribution transformer capacity owned by utility [Volume in MVA's (0's)] (DPA0501)	Actual	The data was obtained utilising a GIS (Geographical Information System) query that determines the total In-Service distribution transformer metrics. The data from GIS is made available through a BI (Business Intelligence) report called the 'Asset Installation Report'.	N/A	GIS provides the data for a BI (Business Intelligence) report that provides the installed total distribution transformer MVA.	N/A	For the year 2017 the data was obtained utilising a GIS (Geographical Information System) query that traces via the installed network connectivity model in GIS the distribution transformer connected.
BMPAL3.5BOP5	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Distribution transformer capacity owned by High Voltage Customers [Volume in MVA's (0's)] (DPA0502)	Estimated	CIS O/V for HV Customer NMIs and SAP Hana for customer maximum demand data.	An estimate was required as there was no customer transformer MVA capacity data available. As Powercor do not own the customer's transformer, the MVA capacity information is not required and has not been documented. The summation of customer maximum demand is used as an estimate of transformer capacity as proposed by the AER.	Report obtained from CIS O/V to determine which customers are on a HV tariff. From that list a SAP Hana report is run to sum the HV customer MD's (Used HV customer NMI's).	N/A	Powercor has provided an estimated distribution transformer capacity owned by High Voltage Customers as a record of HV Customer installed capacity is not registered or maintained for accurate information to be recalled. The estimated data are is accordance with the definitions in chapter 9.
BMPAL3.5BOP6	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Cold spare capacity included in DPA0501 [Volume in MVA's (0's)] (DPA0503)	Actual	It is not current policy in Powercor to operate the electricity distribution network with 'cold spare' distribution transformer capacity (in the form of actual transformers). However, it is policy to operate the electricity distribution network with a strategic level of spare distribution transformers held in store. A SAP inventory query was used to determine the year ending stock position for this metric.	N/A	A SAP inventory query was developed to determine the year ending stock position for this metric.	N/A	Electronic stores inventory records in SAP where accessed, queried and evaluated to determine the number and ratings of distribution transformers held in stock at the year ending for the reporting period as detailed in this Information Notice. The queries and evaluations excluded the number and capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.
BMPAL3.5BOP7	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Total installed capacity for first step transformation where there are two steps to reach distribution voltage [Volume in MVA's (0's)] (DPA0601) Total installed capacity for second step transformation where there are two steps to	Actual	The data was obtained utilising: - GIS (Geographical Information System) query that determines the total In-Service Zone Substation Transformer metrics. The data from GIS is made available through a BI (Business Intelligence) report called	N/A	GIS provides the data for a BI (Business Intelligence) report that provides the installed Total Zone Substation Transformer MVA.	N/A	For Powercor this metric comprises the sum of two variables; the 'Total zone substation transformer capacity where there is only a single step of transformation to reach the distribution voltage (DPA 0603) and the cold spare capacity of zone substation transformers (DPA0605) as specified in this

			reach distribution voltage [Volume in MVA's (0's)] (DPA0602) Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage [Volume in MVA's (0's)] (DPA0603) Total zone substation transformer capacity [Volume in MVA's (0's)] (DPA0604) Cold spare capacity of zone substation transformers included in DPA0604 [Volume in MVA's (0's)] (DPA0605)		the 'Asset Installation Report' - SAP - The Condition Based Reliability Maintenance (CBRM) System The 'Asset Installation Report' was used to determine this metric which was compared to the data in SAP and the CBRM database to provide the final data.				Information Notice, hence DAP0601, 1st step of transformation = 0 as Powercor do not have these DPA0602, 2nd step of transformation = 0 as Powercor do not have these DPA0603, Single step of transformation to reach the distribution voltage = the reported value DPA0604 is the sum of DPA0601-0603 & DPA0605 DPA0605, Cold spare capacity = the reported value
BMPAL3.5BOP8	3.5	Physical Assets	TABLE 3.5.3 - PUBLIC LIGHTING Public lighting luminaires [Volume (0's)] (DPA0701)	Actual	Based on the extract of billable lights extracted from GIS on the last day of the reportable year and provided in the Category Analysis RIN - 3.5. Physical Assets (DPA0701) Public Lighting Luminaires.	N/A	Source data was extracted from the GIS system into MS Excel listing all billable lights on the last day of the reportable year. All lights were multiplied by a 'k' factor (cost sharing) to ensure that luminaires were only counted once.	N/A	With regard to the Final RIN for Economic Benchmarking - Definitions and Instructions provided, 3.5.3 Public Lighting we have reported the number of public lighting luminaires and public lighting poles. We have provided numbers of assets owned by Powercor and assets operated and maintained by Powercor.
BMPAL3.5BOP9	3.5	Physical Assets	TABLE 3.5.3 - PUBLIC LIGHTING Public lighting poles [Volume (0's)] (DPA0702) Public lighting columns [Volume (0's)] (DPA0703)	Actual	Source data was obtained from GIS.	N/A	Source data was extracted from GIS system into Excel listing all public lighting poles on the last day of the reportable year.	N/A	With regard to the Final RIN for Economic Benchmarking - Definitions and Instructions provided, 3.5.2 Public Lighting we have reported the number of public lighting poles. We have provided numbers of assets owned by Powercor and assets operated and maintained by Powercor. Only poles used exclusively to public lighting were counted.
BMPAL3.6BOP1	3.6	Quality of Service	TABLE 3.6.1 - RELIABILITY Whole of network unplanned SAIDI [(0's)] Whole of network unplanned SAIDI excluding excluded outages [(0's)] Whole of network unplanned SAIFI [(0's)] Whole of network unplanned SAIFI excluding excluded outages [(0's)] Whole of network unplanned SAIDI [(0's)] Whole of network unplanned SAIDI excluding excluded outages [(0's)] Whole of network unplanned SAIFI [(0's)] Whole of network unplanned SAIFI excluding excluded outages [(0's)]	Actual	The source is the Annual Regulatory Performance Report and the AER Annual RINs. The originating sources are Outage Management System & Business Intelligence and AER outage exclusions as per the AER STPIS Scheme dated November 2009.	N/A	The current STPIS scheme exclusion methodology and MED Threshold value were applied to the outage order history data to determine the, - 'Inclusive of MED's' data - 'Exclusive of MED's' data.	N/A	- The application of a single MED Threshold value as specified in this Information Notice together with the application of the current STPIS exclusion criteria to the historical data (2006 to 2013 inclusive) has been consistently applied, thereby standardising all the reporting for all the years with 2014. - This means that the 2010-2015 AER STPIS exclusion criteria has been applied to years 2006 to 2009 unplanned data to align the reporting to the current period - As a result of the above the metrics reported for 2006 to 2017 inclusive in this Benchmarking RIN may be different - The actual MED Thresholds applicable for years 2010 to 2012 inclusive used to determine these metrics in the annual reports are different to the single MED value as applied in this Information Notice - The exclusion criteria applicable for the years 2006 to 2009 inclusive used to determine these metrics in the annual reports are different to the exclusion criteria as applicable in this Information Notice.
BMPAL3.6BOP2	3.6	Quality of Service	TABLE 3.6.2 - ENERGY NOT SUPPLIED Energy Not Supplied (planned) [(0's)] Energy Not Supplied (unplanned) [(0's)] Total [(0's)]	Estimated	- Outage Management System, Business Objects & Business Intelligence - Electricity distribution network service providers AER Service Target	Energy not supplied is an estimate of the energy that was not supplied as a	i. The planned energy component is the sum across all the feeders in the STPIS scheme ii. The unplanned energy component is the sum across all the feeders in the STPIS scheme iii. The total energy component is the sum of item i and	N/A	The raw energy not supplied was determined using the third method (average consumption of customers on the feeder based on their billing history) utilising customer consumption aggregated at the

					Performance Incentive Scheme (STPIS), November 2009, particularly section 3.3 Exclusions. The annual customer aggregated consumption data were obtained from the feeder electrical energy meters.	result of customer interruptions. The energy not supplied was determined using the third method utilising customer consumption aggregated at the feeder level in place of the billing data.	item ii above Methodology is as follows: - The individual feeder total aggregated annual energy consumed is used together with the planned & unplanned supply duration parameters exclusive of the excluded outages as specified in this Information Notice.		feeder level in place of the billing data as stated. This aggregated consumption was applied to the planned and unplanned supply duration parameters exclusive of the excluded outages as specified in this Information Notice.
BMPAL3.6BOP3	3.6	Quality of Service	TABLE 3.6.3 - SYSTEM LOSSES System losses [(0's)]	Actual	The source data to calculate annual year losses comprises of purchases data from the IEE database and sales data from CIS.	N/A	The data used was the purchases and sales for the regulatory year in question and then using formula, %Loss = (purchases - sales)/purchases * 100	N/A	The data is based on annual regulatory year losses from 2009 to 2016. Prior to 2009 financial year losses have been used as submitted to the AER as part of the annual Distribution Loss Factor submissions. Powercor have used the financial year losses for 2006 - 2009 due to having not archived the source data therefore unable to spilt/ disclose the data by regulatory year.
BMPAL3.6BOP4	3.6	Quality of Service	TABLE 3.6.4 - CAPACITY UTILISATION Overall utilisation [(0's)]	Actual	DQS04: Overall Utilisation Refer to the Non-coincident Summated Raw System Annual Peak Demand (DOPSD0201) and Total zone substation transformer capacity (DPA0604). The source of Non-coincident Summated Raw System Annual Peak Demand (DOPSD0201) is obtained from TrendScada meter data for Powercor zone substations. For a few Zone Substations MDS was used. Total zone substation transformer capacity (DPA0604) is a summation of DPA0601-0603. There is no installed capacity for DPA0601 & DPA0602. For DPA0603 the data sources are the Annual Regulatory Performance Reports [National Reporting tab] and the AER Annual RINs [General Information tab]. The originating sources are: - Plant & Stations Condition Based Reliability System - Planners Planning Distribution Reports	N/A	The Non-coincident Summated Raw System Annual Peak Demand of Powercor Zone substations is divided by the summation of Powercor Zone Substation transformer thermal nameplate ratings.	N/A	The decrease in utilisation is attributable to the change in methodology used to calculate this figure in 2017 compared with 2016. In 2016, the Non-coincident Summated Raw System Annual Peak Demand of both Powercor zone substations AND customer zone substation values were divided by the summation of Powercor Zone Substation transformer thermal nameplate ratings giving a higher utilisation value. The capacity utilisation is calculated automatically in the table, where the measured non-coincident summated raw zone substation maximum demand (DOPSD0201 is divided by the summation of Powercor Zone Substation transformer thermal nameplate ratings (DPA0604). The thermal nameplate ratings of the zone substations are reported annually from 2006 to 2012 in the Distribution System Planning Report (DSPR) and from 2013 - 2016 Distribution Annual Planning Report (DAPR) and are in accordance of the definitions in chapter 9.
BMPAL3.7BOP1	3.7	Operating Environment	Table 3.7.1 - Density Factors	Estimated	The ratios are derived from variables found in the Benchmarking RIN. Refer to the relevant Basis of Preparation for the original source of these fields.	These variables are ratios and are therefore dependent upon whether the variable used in the ratio is an actual figure or an estimate. As at least one variable is an estimate, these ratios have been considered as an estimate as well.	Customer density (DOEF0101) - calculated by: 3.4.2.1 Total customer numbers (DOPCNO1) divided by 3.7.3 Route Line Length (DOEF0301) Energy Density (DOEF0102) - calculated by: 3.4.1 Total energy delivered (DOPED01) divided by 3.4.2.2 Total customer numbers by location (DOPCNO2) multiplied by 1000 Demand Density (DOEF0103) - calculated by: 3.4.3.3 Non-coincident Summated Raw System Annual MD (DOPSD0201) divided by 3.4.2.2 Total customer numbers by location (DOPCNO2) multiplied by 1000	N/A	The customer, energy and demand density were calculated using the variables as stipulated in the requirements of the notice.

BMPAL3.7BOP2	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Rural Proportion [(0's)]	Estimated	GIS was the originating data source. With respect to historical Overhead Conductors and Underground Cables circuit lengths: The circuit length and route line length of the overhead conductors was obtained from GIS. The circuit length of the underground cables was obtained from GIS.	No estimation or derivation was necessary for the overhead conductors. An estimation was necessary for the underground cables as no data from GIS was available.	Overhead Conductors The data was obtained utilising a GIS query that summates the total of the overhead span lengths to determine the route line length. Underground cables The data could not be obtained utilising a GIS (Geographical Information System) query that summates the total of the underground network section lengths, to determine the total underground route line length Assumptions made to estimate the underground route line length were as follows: - That the underground cable circuit lengths reported in the 2006 to 2012 Annual Regulatory Reports were derived from GIS queries that are reasonably consistent with those currently used - For Powercor Urban the ratio of underground route length to circuit length is 0.90 - For Powercor Rural Short the ratio of underground route length to circuit length is 1.00 - For Powercor Rural Long the ratio of underground route length to circuit length is 1.00.	N/A	With respect to Overhead Conductors - Source data was obtained utilising a GIS (Geographical Information System) query that summates the total of the network span lengths to determine the total overhead conductor route line length - Each portion of the network is defined by categories as either being in the Transmission, Urban, Rural Short or Rural Long category - The rural component was then obtained by summing the Transmission, Rural Short and Rural Long overhead route line lengths Note: - The route length includes all spans of high and low voltage greater than 10 metres - Multiple circuit lines within spans have been counted as one line - Overhead elements associated with communication, protection & control and unmetered loads were excluded - Overhead elements in the DNSP's area that are owned by another DNSP were excluded With respect to Underground Cables - The data could not be obtained utilising a GIS (Geographical Information System) query that summates the total of the underground cable network section lengths to determine the total underground route line length, hence an estimate for this metric is included.
BMPAL3.7BOP3	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Urban and CBD Vegetation Maintenance Spans [(0's)] Rural Vegetation Maintenance Spans [(0's)] Total Vegetation Maintenance Spans [(0's)] Total Number of Spans [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria's relevant to our requirements.	N/A	SAP stores all active spans on the network. Feeder class categories are extracted from SAP using BI reporting. The report is then used to filter using the relevant criteria e.g. by Urban and Rural and then obtain a total of the two. Only spans with cutting notifications closed in the relevant year were considered for report.	N/A	Powercor records vegetation against a span, so the count is as required by definition. The spans counted to report 'vegetation management spans' are those that are recorded as having had cutting of vegetation in the relevant year and so meets definition 'A span in Powercor's network that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include Inspection of vegetation Maintenance Spans'. Total number of spans is the count of spans contained in the data file from SAP. Feeder categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant.
BMPAL3.7BOP4	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Average Urban and CBD Vegetation Maintenance Span Cycle [(0's)] Average Rural Vegetation Maintenance Span Cycle [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria's relevant to our requirements.	N/A	Average frequency of cutting cycle (years) is based on the difference between two cutting cycles which lie in different years. A new Span is counted as 1 year for the relevant cutting year. The data was extracted from BI which is stored in SAP.	N/A	Powercor records vegetation against a span, so the count is as required by definition. Feeder categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant. Powercor does not have specific cycles for areas but rather the interval for pruning

									action is based on the particular circumstances of each span and the code allocated indicates the number of years before intervention is expected to be required. This can be more than once per year or periods greater than 5 years. To meet the AER definition we have interpreted area to be the span and have calculated the simple average for all spans in the Feeder classification areas therefore meeting the definition. Average frequency of cutting cycle (years) is based on the difference between two cutting cycles which lie in different year. A new Span is counted as 1 year for the relevant cutting year. The data was extracted from BI reporting for the purpose of RIN data reporting.
BMPAL3.7BOP5	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Average Number of Trees per Urban and CBD Vegetation Maintenance Span [(0's)] Average Number of Trees per Rural Vegetation Maintenance Span [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria's relevant to our requirements.	N/A	Data for the average number of trees within Powercor's Vegetation Maintenance Spans is based on cutting within the relevant year. This includes only trees that require active vegetation management to meet its vegetation management obligations. This excludes trees that only require Inspections and no other vegetation management activities required to comply with Powercor's vegetation obligations, The average number of trees = total number of trees, as extracted via BI report, divided by the total number of spans cut for the relevant year.	N/A	Powercor records vegetation against a span, so the count is as required by definition. Feeder class categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant. The average number of trees per Powercor's maintenance spans is based on cutting completed within the relevant year. This includes trees that only require active vegetation management to meet its vegetation management obligations. This excludes trees that only require inspections and no other vegetation activity. The average number of trees = total number of trees, as extracted via BI report, divided by the total number of spans cut for the relevant year.
BMPAL3.7BOP6	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Average Number of Defects per Urban and CBD Vegetation Maintenance Span [(0's)] Average Number of Defects per Rural Vegetation Maintenance Span [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria's relevant to our requirements. Powercor records Defects on vegetation Maintenance Spans as one, regardless of the number of Defects on the span. Therefore average number of defects = total cut spans (excluding duplicate spans) divided by total spans cut (including duplicate spans).	N/A	Powercor records Defects on vegetation Maintenance Spans as one, regardless of the number of Defects on the span. Therefore average number of defects = total cut spans (excluding duplicate spans) divided by total spans cut (including duplicate spans).	N/A	Powercor records vegetation against a span, so the count is as required by definition. Powercor records Defects on vegetation Maintenance Spans as one, regardless of the number of Defects on the span. Feeder categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant.
BMPAL3.7BOP7	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Tropical Proportion [(0's)]	Actual	Reference to Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature	N/A	Modelling methodology: The Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity) was used to verify that there is no part of the Powercor electricity distribution area as mapped in the	N/A	There is no part of the Powercor electricity distribution area that falls into a geographical region defined as Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology.

					and humidity) was used to identify that there is no 'Tropical Proportion' of the Powercor electricity distribution area as mapped in Powercor's Geographical Information System (GIS).		Powercor GIS that falls into a geographical region defined as Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology, The assumptions made were, That the Hot Humid Summer and Warm Humid Summer regions defined have not changed since 2006, and therefore can be applied across all years from 2006.		Note: - The AER has verified & approved that no part of the Powercor distribution network falls into a geographical region defined as Tropical.
BMPAL3.7BOP8	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Standard Vehicle Access [(0's)]	Estimated	GIS was the originating data source. As no specific data exists in relation to the accessibility of poles and spans, the actual percentage of the Powercor distribution network that is inaccessible by a standard vehicle is unknown., The estimated route length is based on the assumption listed.	As no specific data exists in relation to the accessibility of poles, this estimate utilises data which is currently available within Powercor GIS to produce the estimated route length of line which does not have standard vehicle access and is considered to be a suitable approach.	Powercor's Geographical Information System (GIS) does not specifically contain detail about standard vehicle accessibility to our assets. The exact percentage of these poles that do not have standard vehicle access is unknown. Some will have access via 2WD vehicle all year round while others may only have access via 2WD vehicle for a very short period over summer (e.g. Otway Ranges). Some poles could be located close to roads and would have access from a 2WD vehicle. Our systems do not record this information. Against each pole we record attributes which include Pole Classification, Pole Site Access and Pole Sites Characteristics. Utilising this information allows us to provide an estimate of the number of Poles where it could reasonably be assumed that we do not have vehicle access 24hr/365 day a year via a two wheel drive (2WD) vehicle. To calculate the number of poles which may not have standard vehicle access we apply the following assumptions to the GIS pole data: - All LV poles have Standard Vehicle Access. - Poles in Non-Fire Area have Standard Vehicle Access. - Poles where Site Access = Paddock or Unknown could have restricted standard vehicle access - Poles where Site Characteristics = Grass, Soil, Water, rock or Unknown could have restricted standard vehicle access. - It is assumed that 40% of the Poles identified do not have 2WD access all year round. This percentage estimate is based on local network knowledge of the Powercor network. Non Standard Vehicle Poles = Poles With Possible Site Access Issues X 40%, We then convert this into an overall % of poles which do not have standard vehicle access. By multiplying this % poles by the overhead Route length we obtain the length of line with Non Standard vehicle Access. Non Standard Vehicle Access (km) = (Non Standard Vehicle Poles X Overhead Line Route length) / Total Number of Powercor Poles	N/A	The data required to meet the requirements of this Information Notice has been estimated for 2017 based on the revised set of assumption developed by Powercor for the 2014 Benchmarking RIN. It has not been retrospectively applied to earlier years (prior to 2014) covered by this Information Notice. The 2017 estimate is derived from information within Powercor's Graphical Information System (GIS), and provides an estimate of the route length of the Powercor distribution network that is inaccessible by a standard vehicle, as defined in section 9 of AERs Instruction and Definitions document 'Economic Benchmarking RIN For Distribution Network Service Providers' dated November 2013. A Standard vehicle for the purpose of this metric is defined by Powercor as a 2 wheel drive vehicle which can access the line 365 days a year, 24 hrs a day via normal access means. This methodology meets the requirements of this Information Notice to the best of our abilities.
BMPAL3.7BOP9	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Bushfire risk [(0's)]	Actual	Powercor has a significant number of spans that are in areas designated as high bushfire risk areas. To determine this number a special GIS query (span data) needed to be developed and tested as no current business standard report was available for this metric.	N/A	The principal assumptions are that this data request - Is limited to the Overhead distribution network - Encompasses the High Voltage and Low Voltage conductors - Utilises the specially developed query to provide the required segmentation, that is, designation of each span as being in either a high or low bushfire risk area. To determine Bushfire Risk, the GIS query is filtered to provide a count of the number of spans in 'Fire' and 'Non-Fire' area. Those in the 'Fire Area' are reported as	N/A	Data was obtained utilising a GIS (Geographical Information System) query that traces the in-service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note:

							part of this metric.		Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the criteria specified in this Information Notice - An overhead 22kV Subtransmission component was included as an additional line item for completeness - Overhead elements associated with communication, protection & control and unmetered loads were excluded - Overhead elements in the DNSP's area that are owned by another DNSP were excluded Each individual span in this query is coded as being in either a high or low bushfire fire area. Areas of high and low fire risk areas are reviewed and defined annually by the relevant authorities.
BMPAL3.7BOP10	3.7	Operating Environment	Table 3.7.3 - Service Area Factors Route Line Length [(0's)]	Estimated	With respect to Overhead Conductors, GIS was the originating data source. - The overhead conductor Circuit Lengths and Route Lengths were both obtained from GIS, With respect to Underground Cables, - Only the underground cable circuit length was obtained from GIS.	No estimation or derivation was necessary for the overhead conductors. An estimation was necessary for the underground cables as no data from GIS was available.	Overhead Conductors The Overhead Route Line Length data was obtained utilising a query that summates the total of the overhead span lengths in GIS, to determine the Route Line Length - Spans less than or equal to 10 metres in length were excluded - Multiple circuit lines within spans were counted as one line Underground Cables The data could not be obtained utilising a GIS (Geographical Information System) query that summates the total of the underground network section lengths, to determine the total underground route line length. Assumptions made to estimate the underground route line length were as follows: - That the underground cable circuit lengths reported in the 2006 to 2012 Annual Regulatory Reports were derived from GIS queries that are reasonably consistent with those currently used - For Powercor Urban the ratio of underground route length to circuit length is 0.90 - For Powercor Rural Short the ratio of underground route length to circuit length is 1.00.	N/A	With respect to Overhead Conductors: The data was obtained utilising a GIS (Geographical Information System) query that summates the total of the overhead network span lengths, to determine the total Overhead Route Line Length. - Spans less than or equal to 10 metres in length were excluded - Multiple circuit lines within spans were counted as one line Note: - The Overhead Route Line Length includes all spans of high and low voltage greater than 10 metres in length - Overhead elements associated with communication, protection & control and unmetered loads were excluded - Overhead elements in the DNSP's area that are owned by another DNSP were excluded. With respect to Underground Cables: The data could not be obtained utilising a GIS (Geographical Information System) query that summates the total of the underground network section lengths to determine the total Underground Route Line Length, hence an estimate for this metric was used.