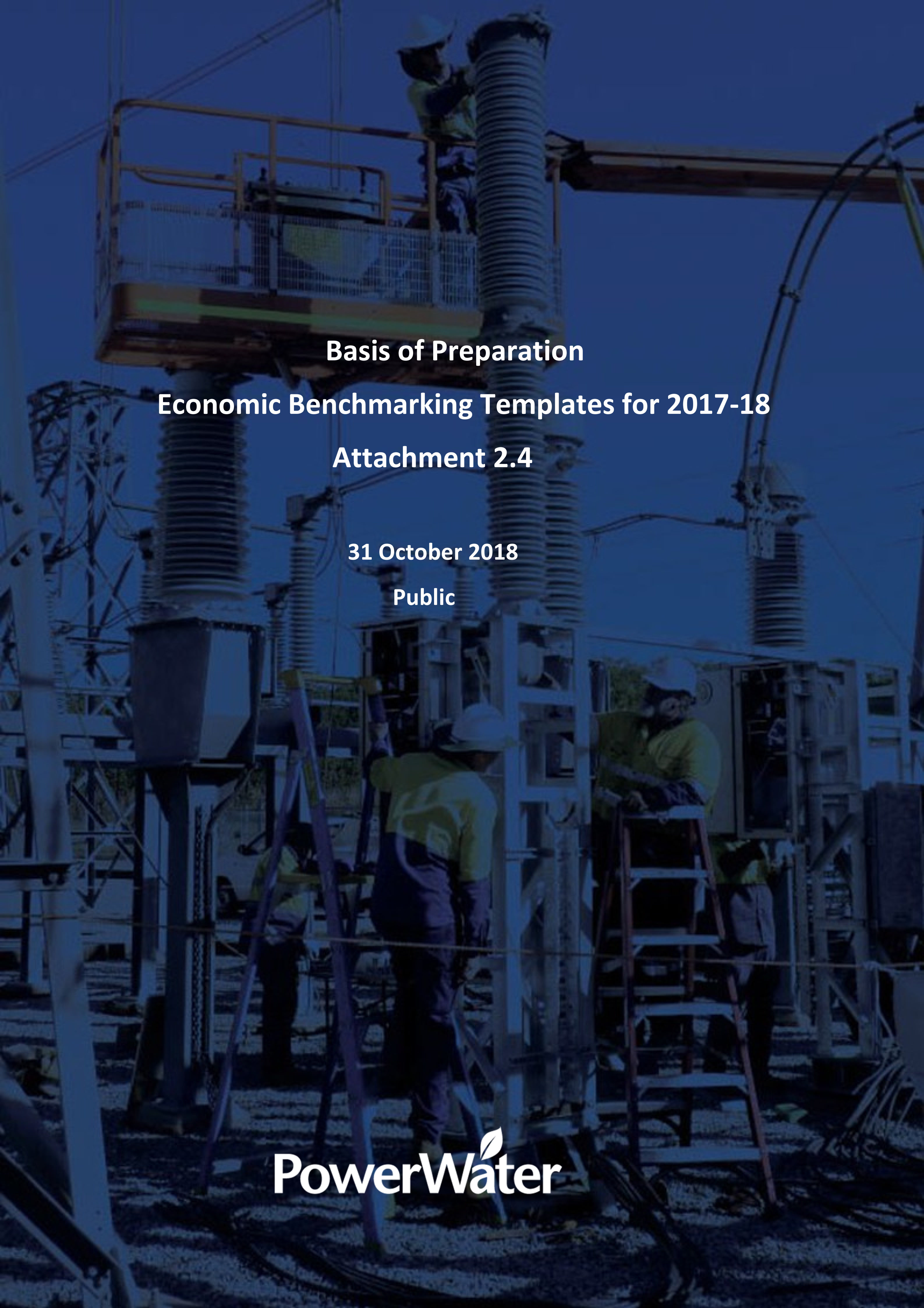

Basis of Preparation

Economic Benchmarking Templates for 2017-18

Attachment 2.4

31 October 2018

Public

PowerWater

Contents

Overview

On 17 August 2018, the Australian Energy Regulator (AER) issued Power Water Corporation (Power and Water) with a Regulatory Information Notice (RIN) on economic benchmarking for 2017-18. The RIN requires we prepare a basis of preparation addressing the templates in the Microsoft Excel workbooks. We have prepared the response based on the order of templates.

We have also provided appendices for detailed information referred to in multiple templates. The appendices are the capex methodology (Appendix A), repairs and maintenance methodology (Appendix B), and operating expenditure methodology (Appendix C).

We have structured our basis of preparation to reflect the order of templates in the AER's Microsoft Excel workbooks. We have explained:

- The source of the information.
- Whether the information provided is actual and estimate based on the AER definitions, and if an estimate how it is the best method.
- How we have complied with the RIN requirements.
- The methodology and assumptions we used to calculate the information.
- Whether the information contains confidential information.
- How we have complied with the RIN requirements.

We expect that the AER will publish the final form of the basis of preparation and the associated data template with our information. The information was collected and provided in good faith and was based on every effort to comply with the requirements of the RIN. In doing so, we have had to estimate some data because we did not have the capability to report the information specified by the RIN. As the data is estimated, we recommend caution in using the data for benchmarking or other analysis.

We developed our best estimate in good faith, with the objective of providing the most accurate data given the RIN requirements. For all estimated information, the RIN requires we provide reasons for why we consider the estimate to be our best estimate. In our circumstances our estimate was 'best' because:

- We were only able to develop a single method for the majority of estimated information.
- The estimated information was prepared and reviewed by subject matter experts.

In all instances where we have provided estimated rather than actual information, we assessed available alternatives to determine the most appropriate estimation technique. All estimated information included in the RIN are our best estimates and we have explained how the estimate has been calculated in the relevant section of the Basis of Preparation.

Template - 3.1 Revenue

Table 3.1.1 - Revenue grouping by chargeable quantity

Table 3.1.2 - Revenue grouping by customer type or class

Source of Data

The revenue accounts for standard control services (SCS) and alternative control services (ACS) were extracted from Power Networks regulated Profit and Loss statement. Supporting information was also sourced from the Network Metering System (MV90), the Financial Management System (FMS) and the Retail Management System (RMS).

Estimated or actual information

The information provided is actual as it relates to information in internal records such as the Profit and Loss Statement and financial systems. Where allocations of revenue were required, we used data from financial systems. In our view, an alternative method would not have yielded materially different outcomes.

Methodology and assumptions

The revenue accounts for standard control services and alternative control services were extracted from Power Networks' regulated Profit and Loss (P&L) for 2017-18. In instances where we could not provide revenue based on AER service classifications from the P&L we used:

- Supporting information on consumption and demand data from MV90 and RMS; and
- Trial balance listings from FMS to allocate revenue.

We still ensured that the total revenue amounts reconciled to Power Networks regulated P&L for 2017-18.

Under our existing regulatory determination, we do not separately charge for metering services. Therefore, to apply the AER's approved service classification for 2017-18, we allocated 3 per cent of current SCS network tariff to the ACS Metering service classification. This was based on the average of the two ratios:

- ACS metering assets value to SCS asset value.
- SCS revenue building blocks to ACS metering revenue building blocks.

Confidential Information

The information in the template is not confidential.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 3.1: PWC must report revenues split in accordance with the categories in Economic benchmarking workbook. The Economic benchmarking workbook requires PWC to report revenues by chargeable quantity (table 3.1.1) and by type of connected equipment (table 3.1.2). The total of revenues by chargeable quantity must equal the total of revenues by type of connected equipment because they are simply two different ways of disaggregating total revenue.	Each row in tables 3.1.1 and 3.1.2 has been reported for 2017-18 and the annual totals are equal as required.
Clause 3.2: PWC must report revenues split into standard control services and alternative control services in accordance with the service classifications for the most recent completed regulatory year.	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined it its Framework and Approach paper. Therefore, the revenue data has been split into SCS and ACS in accordance with the AER's classification of services in its Framework and Approach Paper.
Clause 3.3: PWC must enter '0' into cells that have no effect on the revenues PWC. For instance, if PWC does not use a shoulder period for energy delivery charges then the amount of revenue reported for the variable would be '0'.	All unused cells have '0' entered.
Clause 3.4: Revenues should be able to be reconciled to reported revenues in the regulatory accounting statements for each regulatory year.	Revenue data on tables 3.1.1 and 3.1.2 reconciles to our audited financial accounts.
Clause 3.5: Revenues reported [in template 3.1.1] must be allocated to the chargeable quantity: (a) Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by PWC to customers (the chargeable quantities are the variables DREV0101- DREV0112); (b) Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other Sources' (DREV0113); and (c) 'Revenue from unmetered supplies' is the same for table 3.1.1 as for table 3.1.2, so they must be equal.	We allocated revenue to the most appropriate category based on the type of charge and tariff. Data for revenue from unmetered supplies in table 3.1.1 equals that in table 3.1.2.
Clause 3.6: Economic benchmarking workbook, regulatory template - 3.1, table 3.1.2-Revenue grouping by customer type or class: (a) PWC must	We allocated revenue to the most appropriate category based on the type of charge and tariff, which in turn relates to specific customer types.

allocate revenues to the customer type that most closely reflects the customers from which PWC received its revenue; (b) Revenues that PWC cannot allocate to the customer types DREV0201–DREV0205 must be reported against 'Revenue from other customers' (DREV0206).	

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

We have no incentive schemes that invoke a revenue penalty or allowance. The source data for this conclusion is Schedule 4 of Part B of the Utilities Commission Final Network Price Determination. The determination shows that the control mechanism that applies to 2014-19 regulatory years does not include a variable to adjust revenues for incentive schemes.

Template - 3.2 Operating Expenditure

Table 3.2.1 - Current opex categories and cost allocations

Table 3.2.2 – Opex consistency: current cost allocation approach

Source of Data

Operating expenditure for distribution services was sourced from our Trial balance. Labour cost adjustments were sourced from Maximo (our Asset Management System). Connections expenditure for ACS was sourced from the data we provided in the Category Analysis RIN in template 4.3 ("Fee Based Services").

Estimated or actual information

The information is an estimate based on RIN definitions. An estimate was required due to the labour adjustment made to individual business units as discussed in the methodology section of this response. We could have made alternative assumptions that would have resulted in materially different costs for opex categories, and for this reason we consider the reported data is estimated.

Methodology and assumptions

General methodology

Our 'Power Networks' operating unit provides distribution services provided within Power and Water Corporation.

Other operating units within Power and Water Corporation that indirectly provide distribution services are Finance, Corporate, Retail and System Control. The costs attributed to Power Networks in the audited statutory accounts are related to electricity distribution services. The total cost of the regulated distribution services is included wholly within Power Network's accounts, which includes its portion of the costs allocated from Finance, Corporate, Retail and System Control.

The Trial Balance for Power Networks is the source of the operating expenditure reported in the RIN for distribution services. The Power Network's Trial Balance is a subset of the Power and Water Corporation Trial Balance that was used to develop the audited statutory accounts Profit and Loss (P&L) Statement. Consequently, the operating expenditure amounts reported in the RIN reconcile to the Audited Statutory Accounts. After excluding certain non-expenditure accounts, such as Interest Expense and Depreciation Expense, all costs were allocated to the following services:

- Distribution Services, which are split into: Standard Control Distribution Services, Alternative Control Services - Metering (Types 1 to 6), Alternative Control Services - Fee Based Service, and Alternative Control Services - Quoted Services
- Non-Distribution, unregulated services (not reported in the template).

A key part of the methodology in calculating the historic operating expenditure for the RIN was the application of the AER approved Cost Allocation Method (CAM). In summary, the CAM requires:

- Costs that could be attributed directly (and wholly) to an individual Distribution Service, were attributed to that service. We have determined this using the RIN definition of "Direct Cost", which relates to costs that are based on "*work activity, project or work order*". We have used our Trial Balance and classified every account as either direct or indirect. That is, accounts were classified as direct if they were wholly attributable to a work activity, project or work order, which could subsequently be attributed to the provision of a distribution service. All other accounts were deemed to be unallocated.
- All unallocated costs were attributed to the distribution services based on the proportion of the amounts directly allocated as described in the previous step.

We made some specific adjustments to ensure an appropriate estimate for each variable could be provided as described below.

Labour recovery adjustments

We book the time of employees against projects and programs of work in our asset management system (Maximo) to establish the project or program cost. The cost data associated with each work order in Maximo corresponds to Repair and Maintenance or Capex accounts in the Trial Balance. The same labour cost is inherently included in each of Power Networks' business unit salary and remuneration accounts.

The audited statutory accounts include labour recovery accounts that ensure the amounts are not double counted for financial purposes. However, this recovery is applied at the total expenditure level and does not allow an estimate of labour cost to be established for every RIN category. To avoid double counting and to allow labour to be reported in the RIN templates, the total labour cost booked to projects and programs was used to calculate an adjustment amount needed to reduce the labour and remuneration accounts in the Trial Balance.

The adjustment amount was used to reduce the labour and remuneration costs of all business units proportionately because there is no way to calculate how much labour in each business unit was booked to repairs and maintenance or capex projects. Making the adjustment to the individual business units was important to ensure an appropriate amount of labour was attributed to each distribution service.

2017-18 Capitalisation of indirect costs and unallocated costs

We have applied our Statutory Capitalisation Policy, which includes the capitalisation of an allocation of indirect support costs where they were deemed to be integral to the acquisition or construction of capital assets, provided they complied with AASB 116 Property, Plant and Equipment. We capitalise the same corporate and network overhead accounts for regulatory purposes but do so in proportion to the ratio of direct capex to total direct costs. If the ratio changes, the fraction of unallocated costs capitalised also changes. This is provided for in the AER-approved CAM.

Opex for Network Services

Opex for network services has been calculated as the total expenses attributed to SCS. We excluded the following costs from Power Networks expenses:

- ACS metering costs - these were identified by work orders and business unit costs.
- ACS fee and quoted services - these were identified by work orders and business unit costs.
- Unregulated activities (street lighting and remote communities related services) - these were identified by work orders, business unit and entity.
- Unallocated costs were identified as overhead costs and network costs that contribute to all distribution services.

The remaining costs were used as an estimate of SCS direct costs. In addition, a portion of unallocated costs were allocated to SCS opex using the approach described in the CAM.

Opex for metering

Opex for metering services has been reported as the total expenses attributed to ACS metering. This includes:

- Costs identified as business unit 223 metering, except allocated overhead costs.
- Costs identified as metering in asset management work orders.
- Overhead and non-network costs allocated to ACS metering through the application of the CAM.

Opex for Connection Services

All SCS Connection Services expenditure is capitalised, and therefore the opex for connections services is reported as zero. Within ACS, the AER has described energisation, de-energisation and re-energisation as Fee Based Services as Connection Services. We have used the values reported in template 4.3 of the Category Analysis RIN as the basis for identifying opex for these services.

Opex for Public Lighting

The AER has not classified public lighting as SCS or ACS because our street lighting service is provided by local councils. We have entered zero for public lighting variables.

Opex for Amounts Payable for Easement Levy or Similar Direct Charges on DNSP

We have not incurred any costs relating to easement levies so this variable has been reported as zero.

Opex for major generation connection point planning

We identified known major generation connection projects using data in our financial systems. We were able to identify the opex component associated with these projects. These were part of network services.

Confidential Information

There is no confidential material in these templates.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 4.1: For all tables, opex must be split into standard control services and alternative control services in accordance with the service classifications for the most recent completed regulatory year.	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined it its Framework and Approach paper. Therefore, the data has been split into SCS and ACS in accordance with the AER's classification of services in its Framework and Approach Paper.
Clause 4.2: In addition, opex must be split into the variables as defined in Appendix F for Economic benchmarking workbook, regulatory template 3.2, table 3.2.2.	We have split opex into the defined categories as per Appendix F.
Clause 4.3: Where PWC does not incur opex for a particular variable a '0' must be entered into these cells. For example where PWC does not provide a service as a part of standard control services or alternative control services, PWC must enter '0' in the cells that correspond to that service.	We have reported zero for variables which do not incur such expenses. Specifically, public lighting is not classified as SCS or ACS, so all costs have been reported as zero. Further, we have no costs relating to "Opex for amounts payable for easement levy or similar direct charges on DNSP" and have reported zero for this variable.
Clause 4.4: Opex must be reported inclusive of margins and opex for dual function assets.	We do not have dual function assets and there is no margin to report so these have been included, at zero value.
Clause 4.5: Economic benchmarking workbook, regulatory template 3.2, table 3.2.1 Opex categories - current opex categories and cost allocations: (a) PWC must report opex using its current opex categories	We have reported opex using our current financial categories.
Clause 4.6: Opex must be prepared for all regulatory years in accordance with PWC's cost allocation method and the service classifications for the most recent completed regulatory year. Economic benchmarking workbook, regulatory template 3.2, table 3.2.2 Opex consistency --- current cost allocation approach:	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined it its Framework and Approach paper. We have applied the approved CAM to 2017-18 expenditure and applied the Framework and Approach service classifications.

Clause 4.6 (a): This table is intended to collect consistent opex line items for economic benchmarking. Network services opex is requested as this is the core service which we intend to benchmark. Other services are collected so that their impact on productivity can be assessed and they can be incorporated or excluded from the services being benchmarked if necessary.	Network Services opex has been reported as equal to SCS opex as it is assumed to not include metering, connections or public lighting.
Clause 4.6 (b): The opex categories in this table are not intended to be mutually exclusive or collectively exhaustive. This means that the totals of opex in this table may be greater or less than PWC's actual opex. Further, opex may be double counted within the line items.	We have reported these categories in total with opex for major generator connection point planning assumed to be included in Network Services opex, otherwise there is no double counting of opex.
Clause 4.6 (c): Opex must be prepared in accordance with PWC's cost allocation method and the service classifications for the most recent completed regulatory year.	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined it its Framework and Approach paper. We have applied the approved CAM to 2017-18 expenditure and applied the Framework and Approach service classifications.

Table 3.2.4 - Opex for high voltage customers

Source of Data

The data on High Voltage (HV) customers and loading was sourced from the same data we used to complete template 3.5 of the Economic Benchmarking RIN ("Physical Assets"). We used estimated installed capacity as a basis for this information. Estimated unit rates was sourced from expenditure recorded in our asset management system on distribution substation.

Estimated or actual information

Information on the opex for high voltage customers is not recorded in our systems. We used estimated installed capacity as a basis for determining the number of HV customer distribution substations. An alternative estimate may have resulted in a materially different outcome, and for this reason the data is estimated.

Methodology and assumptions

Information from the Category Analysis (CA) RIN template 2.8 was used to determine the opex for high voltage customers.

Distribution substation opex was calculated by summing the Maintenance Asset Categories "Distribution substation - transformers", "Distribution substation - property", "Distribution substation - switchgear" and "Distribution substation - other equipment" in table 2.8.2 for Routine maintenance and Non-routine maintenance. This expenditure was then divided by the volumes in table 2.8.1 to give a unit cost per distribution substation.

The number of HV customer distribution substations was estimated using the Installed Capacity for HV Customers in Economic Benchmarking RIN Template 3.5. It was assumed that the quantity of substations for each customer was their estimated installed capacity rounded up to the nearest whole number. For example, a customer with 0.8MVA installed capacity was assumed to have a single distribution substation, and a customer with 1.2MVA installed capacity was assumed to have two distribution substations.

The unit rate was then applied to the estimated number of HV customer distribution substations to calculate the final opex for high voltage customers.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 4.7: Economic benchmarking, regulatory template 3.2, table 3.2.4 Opex for distribution transformers owned by high voltage customers (a) PWC must report the amount of opex that it would have incurred had it been responsible for operating and maintaining the electricity distribution	We have estimated the opex required to maintain distribution transformers owned by customers in accordance with this requirement.
(b) Where actual information is unavailable, this must be estimated based on the opex PWC incurs for operating similar MVA capacity distribution transformers within its own network. Where the MVA capacity of high voltage customer-owned distribution transformers is not known, it must be approximated by the observed maximum demand for that customer.	Actual information is not available and it has been estimated using the method required.
(c) The data in this table will not reconcile to amounts reported in the regulatory accounting statements as it does not relate to services provided by PWC.	The data in this table is not our opex and does not reconcile to any of our financial or regulatory reports.

Template - 3.2.3 Provisions

Table 3.2.3 - Provisions

Source of Data

The source of data is our trial balance and information in our financial accounts relating to allocation of standard control services between opex and capex.

Estimated or actual information

The information provided is actual. All the data in this template is materially dependent on our trial balances. However, the last step in the methodology is to apportion the provisions data into opex and capex, and then SCS. This allocation was undertaken using actual information from our financial accounts. Consequently, the RIN defines the information in this template to be actual information.

Methodology and assumptions

We have undertaken the following steps to complete this template from actual financial system data:

- Extracted the financial data that applied to the provision of distribution services. Our statutory accounts ensure all costs of the electricity network - regulated areas, including overheads are recorded in Entity 21 relating solely to "Power Networks - Regulated". Utilising this extract was the simplest way to isolate the smallest subset of our statutory accounts that contain the provision data for 'distribution services'.
- Established the opening and closing balances of each account for Power Networks - Regulated. The information reconciles back to the trial balance and the audited year-end reconciliation.
- Established the amounts used during the year for "Power Networks - Regulated". This information is provided by NT Department of Corporate and Information Services (DCIS) through a Personnel Information and Payroll System (PIPS) report, and the use of a financial report.
- Established the amounts added during the year for "Power Networks - Regulated".
- Ensured the opening balance plus the additions and less the amounts used are equal to the closing balance.

The above methodology is explained in more detail for each provision as follows.

Provisions for Long Service Leave and Recreation Leave

The closing balance for each provision is recorded in the trial balance for each year against different account codes. This information is also included in the account reconciliations that are subject to audit as part of statutory audit of the financial statement. In addition, the closing balance is the opening balance for the following year.

The general ledger codes used to identify the opening and closing balance amounts from the trial balance is as follows:

- Long Service Leave: Current Long Service Leave Provision (67-014), and Long Service Leave Payment in Lieu (67-688).
- Recreation Leave: Current Recreation Leave Provision (67-013), Rec Leave Payment in Lieu (67-686), Rec Leave Cash Up (67-687) Rec Leave Loading (67-015), Leave Fares (67-685).

The amounts used for long service leave and recreation leave provisions were calculated using the payroll report (PIPS) for 2017-18 financial year. This equates to the actual amounts paid out in relation to those staff members who used long service leave entitlements and whose labour cost was booked to the “Power Networks – Regulated” entity.

The additional provisions made in the period for long service leave and recreation leave are the movements in provision less the amounts used.

Provision for Fringe Benefits Tax (FBT)

The closing balance for provision for FBT is recorded in the trial balance report for each year against the account for provision for fringe benefits tax (67-681). This information is also included in account reconciliations that are audited annually. In addition, the closing balance is the opening balance for the following year.

The amount used is the actual FBT Return lodged and paid to the Australian Taxation Office (ATO) during the year. In addition, since the FBT year runs from 1 April to 31 March, the amount used also includes an accrual for the last quarter of the previous financial year (April to June 2018). The calculation is based from the most recently lodged FBT Return - divided by twelve then multiplied by three months.

The additional provisions made in the period are the monthly FBT expense accruals. The accrual calculation is based on the most recently lodged FBT Return divided by twelve months.

Provision for Payroll Tax

The closing balance for provision for payroll tax is recorded in the trial balance report for each year against the code (67-682).

Additions to provision constitute the monthly accrual for NT payroll tax. The calculation is made by summing up the wages paid to employees that are subject to payroll tax (i.e. salary, allowances, leave provisions, fringe benefits and superannuation) less any applicable exemptions (i.e. exemption for graduates and apprentices and workers compensation).

The total is then multiplied by the 5.5% NT payroll tax rate. The amount used is the actual monthly NT payroll tax payments made during the year. Since lodgment and payment for payroll tax is done a month after, payroll tax for the month of June is paid the following year.

Allocation method

The total for each provision for "Power Networks – Regulated" is split between capex and opex. The capex portion was calculated using the proportion of total labour cost used for capital projects. The proportion of standard control services in both opex and capex is calculated using the proportion to the total labour costs (opex and capex) used for standard control services.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 4.8(a): Financial information on provisions relating to standard control services must be reported in accordance with PWC's cost allocation method and the service classifications for the most recent completed regulatory year.	Our AER approved CAM allocates the costs of providing distribution services into the services classified by the AER in its Framework & Approach. It should be noted that the approved CAM does not include a methodology to allocate provisions data. The allocation of the provision amounts into the SCS has been performed consistently with the proportion of total labour costs used for SCS as discussed in the methodology.
Clause 4.8(b): Financial information on provisions should be able to be reconciled to the reported amounts for provisions in the regulatory accounting statements for each regulatory year.	PWC are unable to fulfil this requirement due to provisions not being reported in our regulatory accounts.
Clause 4.8(c): PWC must report financial information for each of its individual provisions. A provision is an account which records a specific present liability of an entity to another entity. Examples of provision accounts include employee entitlements, doubtful debts and uninsured losses. PWC must complete the table for each individual provision and must add rows as necessary to the template for this purpose.	We have reported our individual provisions, being provisions for the liabilities of Long Service Leave, Recreation Leave, Fringe Benefits Tax, Payroll Tax. We do not have any other provision accounts associated with Distribution Services.
Clause 4.8(d): For each additional provision specify the name of the provision and add variable codes for line items. A letter or letters must be added to the end of each variable code link it to the provision. For example, the variable codes for the first additional provision would be DOPEX0301A to DOPEX0312A, variable codes for the second would be DOPEX0301B to DOPEX0312B and the variable codes for the 28th provision would be DOPEX0301AA to DOPEX0312AA.	The names are as follows: 1. Long Service Leave - DOPEX03A to DOPEX0314A 2. Recreation Leave (includes Recreation Leave, Recreation Leave Loading and Recreation Leave Fares - DOPEX03B to DOPEX0314B 3. Fringe Benefit Tax - DOPEX03C to DOPEX0314C 4. Payroll Tax - DOPEX03D to DOPEX0314D

Template - 3.3 Assets

Table 3.3.1 - Regulatory asset base values

Source of Data

Actual additions and disposals are sourced from our financial accounts. Other values are sourced from the 2013-14 external valuation report.

Estimated or actual information

This information is sourced from our financial accounts. Therefore, this information is defined by the RIN to be actual information. We have made estimates for allocations of RAB, remaining asset life, and average of asset life. However, while these may be inaccurate to a degree, we consider an alternative method of estimation would not yield materially different outcomes. On this basis, we consider the information meets the definition of actual.

Other values are sourced from the 2013-14 external valuation report. This information is not materially dependent on or sourced from any of our systems or other records used in the normal course of business. Therefore, this information is defined by the RIN to be estimated information.

Methodology and assumptions

Table 3.3.1 represents the total RAB for network services (NS), SCS and ACS. All values in this table are calculated based on the sum of each category presented in Table 3.3.2 of the Economic Benchmarking RIN (as described in the next section).

For other, these variables are calculated in accordance with the RIN requirements and a 2013-14 external valuation report.

The primary limitation of the data provided is that it applies the 2016-17 split of depreciated replacement cost (DRC) to allocate some RAB categories to EB categories for periods. Other limitations include:

- Allocations are needed to split the RAB for connection services from the SCS RAB – which may not be accurate even though it is the best estimates
- An accounting approximation is used to determine the weighted average remaining life, which may not be accurate even though it is the best estimate.
- An average of the asset life used by other networks when completing the equivalent Economic Benchmarking RIN tables was used for the standard lives – which may or may not accurately reflect the exact asset life of the assets installed by us from time to time.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 5.1: PWC must report RAB values in accordance with the standard approach and the Assets (RAB) financial reporting framework. This is a standard approach that must be used for RAB disaggregation to be followed by all Distribution Network Service Providers (DNSPs) (the Standard Approach).	The values reported in Template 3.3 are based on the standard approach.
Clause 5.7: RAB assets must be reported inclusive of dual function assets that provide standard control services.	We do not own any dual function assets, so none have been included.
Clause 5.8: The Assets (RAB) financial reporting framework: Standard control services, RAB financial information must reconcile to: (i) For years prior to any AER determination of RAB values, determinations in relation to RAB values made by the previous jurisdictional regulator unless the PWC has had the RAB 'revalued' in the backcast period. In this case standard control services, RAB financial information must reconcile to RAB values of a "rolled back" RAB prepared in accordance with the RAB framework; or	The AER has only made a draft determination of Power and Water's RAB, so this requirement does not strictly apply. The jurisdictional regulator has made determinations in relation to Power and Water's RAB, however the RAB was revalued in 2013-14. After the valuation was completed, errors in this revaluation were identified, which resulted in the RAB being overstated. NT Government officials have indicated that the NT NER (the Rules) will be amended to reflect this lower value. Therefore, the RAB has been rolled back from the corrected revaluation amount in accordance with the RAB framework. Consequently, this roll back is not expected to reconcile with the jurisdictional regulator's published determination. The RAB for 2014-15 to 2017-18 has been reconciled to the Roll Forward Model received in the draft decision with actual values (for gross capital expenditure, asset disposals and customer contributions) substituted for the 2017-18 year.
(ii)For years where the AER has not made a decision on values for the RAB, RAB values must be prepared in accordance with the RAB framework. In this circumstance, actual additions (recognised in the RAB) and disposals must reconcile to amounts reported in the annual financial statements.	The AER has not made a final decision on our RAB in any of the reporting years, so the RAB values have been reported in accordance with the RAB framework as described in the methodology section below. Further, the additions to the RAB and disposals reconcile to amounts reported in the annual financial statements. As "annual financial statements" is not a defined term. We have interpreted this to mean the Audited Statutory Accounts

This means that, for years prior to when the RAB was revalued, the financial data must reconcile to an estimate of the RAB values that has been calculated by rolling back the RAB from the date of its revaluation in accordance with the RAB framework. Rolling back the RAB is the opposite of rolling the RAB forward in accordance with the RAB framework – so additions and inflation are subtracted from the RAB and depreciation is added to the RAB	As noted above, the RAB has been rolled back from the revaluation amount and the additions and disposals reconcile to the statutory accounts. Depreciation was sourced directly from the source files explained further below. Depreciation for the back-cast SCS RAB was automatically (i.e. via formula) adjusted up where necessary to ensure that balances for individual assets did not became negative as part of the roll-back.
Clause 5.9: Closing value in Workbook 2 – Economic benchmarking, regulatory template 3.3, tables 3.3.1 and 3.3.2 is derived from the sum of the opening value; Inflation addition; straight line depreciation; actual additions (recognised in RAB) and disposals. Straight-line depreciation and disposals should be entered as negative numbers.	The closing value has been calculated as the sum of the opening value, inflation, depreciation, additions, and disposals. Where we have received a capital contribution for capital expenditure amounts added to the RAB we have also deducted the capital contribution amount received.
Clause 5.15: PWC must report totals of RAB financial information for all years in this table. The total for the RAB financial information will reconcile with the RAB financial information provided in table 3.3.2.	RAB totals for all years have been provided in table 3.3.1 with the methodology set out below. These values reconcile with those provided in 3.3.2.

Table 3.3.2 - Asset value roll forward

Source of Data

Actual additions and disposals are sourced from financials accounts, but significant modifications have been applied. All other values have been sourced from the 2013-14 external valuation report.

Estimated or actual information

Actual additions are sourced from our financial accounts, however there are significant assumptions applied to allocate these amounts into the EB categories. Depending on the unit rates and other drivers of this allocation, the disaggregation of the additions and disposals could be materially different if alternative assumptions were adopted. Therefore, this information is estimated information as defined by the RIN.

The opening value is calculated in accordance with the RIN requirements and the 2013-14 external valuation report. This information is not materially dependent on sourced from any of our systems or other records used in the normal course of business. Therefore, this information is estimated information.

Methodology and assumptions

We have split our RAB values into the categories for Table 3.3.2 using the standard approach prescribed in clauses 5.10 to 5.12 of Appendix E of the RIN. We used two methods to allocate our RAB to the relevant category including total estimated Depreciated Replacement Cost for 2017, and total book value for the regulatory year 2017.

We have made the following assumptions in preparing the RAB information.

- Valuation adjustments made between periods should be accounted for, which explains why there is a difference between the interim closing balance in the last year of a regulatory period versus the opening balance of the first year in the next regulatory period.
- Additions are assumed to be gross capex less customer contributions.
- The percentages used to allocate RAB categories to EB categories for the SCS, NS and ACS RABs are the same in all years, based on 2016-17 data.
- The weighted average unit rate of replacements costs derived from a sample of applicable projects are indicative for all projects.

The values presented in Table 3.3.2 are the result of a more detailed calculation within the primary source document referred to as the “EB RIN RAB Allocation Model”. The primary purpose of this model is to complete the following steps:

- Link historical and forecast RAB values for SCS and ACS based on RAB asset classes within the proposal.
- Determine what proportion of SCS values relate to network services activities.

- Allocate proposal RAB asset class values into EB RIN categories.
- Calculate the RAB values by category.
- Calculate the associated standard and remaining lives by EB RIN category.

Historical RAB Values for SCS and ACS

We are required to populate RAB values, split by Economic Benchmarking categories for 2017-18. To do this, the model also includes historical data from 2005-06 to 2016-17.

To meet this requirement, the first step is to ensure the total RAB values are correct for each period, regardless of asset categorisation, by referencing alternative sources.

The “Input SCS” worksheet is designed to capture historical and forecast RAB values for SCS. The worksheet is structured to capture the movements by proposal RAB asset class for the categories in the table below which highlights the treatment of each block within the worksheet highlighting which items are sourced from other workbooks and which items link out to key outputs of the model.

- Opening balance - All years calculated. For years prior to the revaluation in 2013, this is calculated by rolling-back the RAB. For years after, this is set as the closing value for the year prior.
- Inflation - All periods after the 2013 revaluation, this is linked to totals in source documents and allocated to proposal RAB asset classes. For years prior this is calculated as the product of inflation for that year and the opening balance
- Straight line depreciation - All periods linked to totals in source documents and allocated to proposal RAB asset classes
- Net additions - All periods linked to totals in source documents and allocated to proposal RAB asset classes
- Disposals - All periods linked to totals in source documents and allocated to proposal RAB asset classes
- Interim closing balance -Calculated as sum of the above, except for the closing balance for 2013, which is sourced from the revaluation adopted by the Utilities Commission. Opening balance of next regulatory period less interim balance, where appropriate
- Closing balance - Calculated as interim closing balance plus adjustments

We have standardised the presentation by proposal RAB asset classes across multiple regulatory periods allowing the historical and forecast values to be presented on a consistent basis. The same approach was followed for the historical periods within “Input_RAB_ACS” for the Alternative Control Services RAB.

Network Services RAB

Network Services RAB is a subset of the SCS RAB. The Network Services RAB (NS RAB) was estimated by removing assets from the SCS RAB relating to the provision of connection services, metering, public lighting and fee and quoted based services.

The metering RAB is classified as ACS and is therefore treated separately. We do not have a RAB relating to public lighting or fee and quoted based services. As we do not have a separate RAB for connection services the NS RAB was estimated by:

- Quantifying net connection related capex.
- Quantifying net capex for asset classes which include connection capex.
- Calculating the proportion of connection related capex.
- Determining the estimated connection RAB by asset category.
- Calculating the NS RAB by subtracting the estimated connection RAB from the total SCS RAB.

Net connection related capex was sourced from table 2.1.1 (gross capex) and 2.1.7 (capital contributions) within our category analysis RIN. Further description of the underlying methods can be found in the basis of preparation relating to these tables.

Based on the RFM and the PTRM we can demonstrate that four RAB asset classes contain connection related capex including distribution lines, LV services, distribution substations and distribution switchgear.

Allocation from RAB asset classes to EB RIN categories

After separating out the RABs into SCS, ACS and NS, we also split our RAB into the EB categories using the AER's prescribed standard approach. The table below sets out RAB categories that could be directly mapped from RAB categories to EB categories, which meant the book value method was most appropriate.

Service Classification	RAB Category	Category
SCS and NS	Substations	Zone substations and transformers
SCS and NS	Distribution substations	Distribution substations and transformers
SCS and NS	Distribution switchgear	Distribution substations and transformers
SCS and NS	Protection	Zone substations and transformers
SCS and NS	SCADA	Zone substations and transformers
SCS and NS	Communications	Zone substations and transformers
SCS and NS	Land and easements	Easements
SCS and NS	Property	Other assets with long lives

SCS and NS	IT and Communications	Other assets with long lives
SCS and NS	Motor Vehicles	Other assets with short lives
SCS and NS	Plant and Equipment	Other assets with short lives
ACS	Mechanical meters – General	Meters
ACS	Mechanical meters – Prepaid	Meters
ACS	Electronic Meters	Meters
ACS	Metering Communications	Other assets with short lives
ACS	Metering - Dedicated CTs and VTs	Other assets with long lives
ACS	Metering - Non-network Other	Other assets with long lives

It was not possible to directly allocate three proposed RAB asset classes, so we used the DRC method to estimate their EB categories values as documented in the table below.

Service Classification	**RAB Category**	**EB categories impacted**
SCS and NS	Distribution lines	Overhead network assets less than 33kV (wires and poles) Underground network assets less than 33kV (cables)
SCS and NS	Transmission lines	Overhead network assets 33kV and above (wires and towers / poles etc.) Underground network assets 33kV and above (cables, ducts etc.)
SCS and NS	LV services	Overhead network assets less than 33kV (wires and poles) Underground network assets less than 33kV (cables)

The DRC method uses the following formula to determine the proportion allocated to each EB category:

DRC = Replacement unit cost (Dollars) x Physical asset (km/MVA) x remaining life (years) / standard life (years).

Assumptions for this calculation are centralised on “Input_DRC” in the RAB Allocation Model.

Calculating the RAB Values by EB RIN category

After determining the percentage allocations to convert the RAB proposal RAB asset classes to EB categories the following worksheets perform the calculation by multiplying the values in the "Input_SCS", "Input_ACS" and "Calc_RAB_NS" sheets by the allocation: Calc_EB _NS, Calc_EB _SCS and Calc_EB _ACS.

The structure of these worksheets presents the RAB values by the following movement types split by EB RIN category: Opening balance, Inflation, Straight-line depreciation, Net additions; Disposals; Interim closing balance; Adjustments; and Closing balance. The purpose of these three worksheets is to recut the outputs (by relinking) to show the movements within each EB category – rather than the EB RIN categories – within a particular RAB movement type.

Outputs from these worksheets link to the live AER template "3.3 Assets (RAB)" which will automatically update each year after adjusting assumptions on the input worksheets.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

We have not addressed clauses 5.13 and 5.14 as these are only required if we pursue the optional reporting. We did not pursue this option.

Appendix E Requirements	Consistency with the Requirements
Clause 5.2: Where PWC believes it has sufficient information to provide a consistent RAB disaggregation into the RAB assets in the Assets (RAB) worksheet that better reflects the values of those assets (the Optional Additional Approach), it may also provide this in a separate Excel worksheet.	We have not used an alternative approach.
Clause 5.3: In both cases we will require the provision of the basis of preparation for the allocated RAB values detailing the calculations undertaken. The disaggregated RAB values developed using the Optional Additional Approach must be reported in accordance with tables 3.3.2 and 3.3.3. In both cases PWC must provide a supporting worksheet detailing the calculations undertaken.	We have used the standard approach as explained in the methodology section below.
Clause: 5.4 Substation land must be included in the 'substation asset' category. Separate values for substation land may be provided in accompanying documentation to the notice response.	Substation land has been included in the substation asset category. No separate values are provided in accompanying documentation.
Clause 5.5: In completing the Economic benchmarking workbook, regulatory template 3.3 PWC must report metering assets in accordance with the service	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined in its Framework and Approach paper. Type 1 to 6 metering is classified as an

classifications for the most recent completed regulatory year	'Alternative Control Service' as per the Framework & Approach paper. As explained in the methodology section below, we have reported the RAB values for these services in the ACS table only.
Clause 5.7: RAB assets must be reported inclusive of dual function assets that provide standard control services.	We do not own any dual function assets, so none have been included.
Clause 5.8: The Assets (RAB) financial reporting framework: Standard control services, RAB financial information must reconcile to: For years prior to any AER determination of RAB values, determinations in relation to RAB values made by the previous jurisdictional regulator unless the PWC has had the RAB 'revalued' in the backcast period. In this case standard control services, RAB financial information must reconcile to RAB values of a "rolled back" RAB prepared in accordance with the RAB framework; or For years where the AER has not made a decision on values for the RAB, RAB values must be prepared in accordance with the RAB framework. In this circumstance, actual additions (recognised in the RAB) and disposals must reconcile to amounts reported in the annual financial statements. This means that, for years prior to when the RAB was revalued, the financial data must reconcile to an estimate of the RAB values that has been calculated by rolling back the RAB from the date of its revaluation in accordance with the RAB framework. Rolling back the RAB is the opposite of rolling the RAB forward in accordance with the RAB framework so additions and inflation are subtracted from the RAB and depreciation is added to the RAB.	The AER has not made a determination of our RAB, so this requirement does not strictly apply. The jurisdictional regulator has made determinations in relation to our RAB, however the RAB was revalued in 2013-14. After the valuation was completed, errors in this revaluation were identified, which resulted in the RAB being overstated. NT Government officials have indicated that the Rules would be amended to reflect this lower value. Therefore, the RAB has been rolled back from the corrected revaluation amount in accordance with the RAB framework. Consequently, this roll back is not expected to reconcile with the jurisdictional regulator's determination. The RAB for 2014-15 to 2018-19 has been reconciled to the Roll Forward Model submitted in the regulatory proposal. The AER has not made a decision on our RAB in any of the reporting years, so the RAB values have been reported in accordance with the RAB framework as described in the methodology section below. Further, the additions to the RAB and disposals reconcile to amounts reported in the annual financial statements. As "annual financial statements" is not a defined term we have interpreted this to mean the Audited Statutory Accounts. As noted above, the RAB has been rolled back from the revaluation amount and the additions and disposals reconcile to the statutory accounts. Depreciation was sourced directly from the source files explained further below. Depreciation for the back-cast SCS RAB was automatically (i.e. via formula) adjusted up where necessary to ensure that balances for individual assets did not became negative as part of the roll-back.
Clause 5.9: Closing value in Economic benchmarking workbook, regulatory template 3.3, tables 3.3.1 and 3.3.2 is derived from the sum of the opening value; Inflation addition; straight line depreciation; actual additions (recognised in RAB) and disposals. Straight-line	The closing value has been calculated as the sum of the opening value, inflation, depreciation, additions, and disposals. Where we have received a capital contribution for capital expenditure amounts added to the RAB we

depreciation and disposals should be entered as negative numbers.	have also deducted the capital contribution amount received.
Clause 5.10: Direct attribution to the AER's economic benchmarking RAB asset classes: (a) Where RAB financial information can be directly allocated to the RAB assets (as per the definitions in Appendix F) it must be directly allocated to those RAB assets. Financial information can be directly allocated to RAB asset class where that financial information relates to assets that wholly fall within the definition of that RAB asset class. For example, financial data associated with poles can be directly allocated to overhead distribution assets (wires and poles).	Where we were able to directly allocate financial values to the RAB assets classes we have done so.
Clause 5.16: Economic benchmarking workbook, regulatory template 3.3, table 3.3.2 Asset value roll forward: a. PWC must report RAB financial information broken down in accordance with the RAB assets as per the definitions in Appendix F. b. Where PWC has previously reported and/or recorded values for easements, these values must be provided separately in the '3.3 Assets (RAB)' worksheet. Otherwise, this should be included in the remaining categories. Where relevant, data that includes easements should be identified.	The RAB financial information provided in table 3.3.2 has been prepared in accordance with the relevant definitions contained in Appendix F. We have separately identified easements in all relevant tables within the '3.3 Assets (RAB)' worksheet
Clause 5.11: Where direct attribution to the economic benchmarking asset classes is not possible: (a) RAB financial information that cannot be directly allocated to a single RAB asset category should be allocated in accordance with the RAB allocation	Where we could not wholly allocate financial information to the RAB assets classes, we have used the RAB allocation approach. We have described this in the methodology section below.

Clause 5.12 a. RAB financial information that can be directly allocated to a group of RAB assets, but cannot be directly allocated to an individual RAB asset category, should be directly allocated to that group of RAB assets, and then allocated across the individual categories in the group in accordance with this RAB allocation approach. b. To allocate RAB financial information across RAB assets, the RAB financial information must be allocated in direct proportion to the relevant RAB asset's share of the total estimated depreciated replacement cost for that year (estimated in accordance with (c) and (d)). In the event that the sum of the estimated disaggregated asset values for the RAB assets for each year that are formed using (c) and (d) do not equal the total value of the RAB for that year, the disaggregated RAB series must be calculated by multiplying the total value of the RAB by each RAB asset's share of the sum of all asset values for that year formed using (c) and (d). c. PWC must estimate the depreciated replacement cost of their assets for each RAB asset for which RAB financial information cannot be directly allocated. This estimation must be made for the most recent year for which the RAB financial information cannot be directly allocated. Where disaggregation is required for the whole period then this will be the 2017 regulatory year. (i) This depreciated replacement cost estimate should be based on the physical asset data provided for lines, cables and transformers in the '3.5. Physical Assets' worksheet of Economic benchmarking workbook (for the relevant RAB asset category); unit rate replacement costs applicable to PWC for each of the physical asset categories and the weighted average asset age relative to the corresponding weighted average service life. (ii)Estimation of the depreciated replacement costs can be undertaken for aggregate asset categories using best endeavours rather than a very detailed exercise. All assumptions, however, should be made clear. (iii) Book values may be used for easements, other long life assets and other short life assets. (d) To estimate the depreciated replacement cost for years prior to the estimated depreciated replacement cost developed under (c), the depreciated replacement cost estimate developed under (c) must be rolled back to 2005-06 using disaggregated capex data and depreciation in accordance with the RAB framework. (e) The allocated values for the 2016-17 regulatory year are to be used as the basis for rolling forward the RAB for regulatory years subsequent to that year.	The RAB allocation approach has been applied to the Distribution Line and Transmission Line asset classes Distribution Line assets were allocated between overhead networks assets less than 33kV and underground networks assets less than 33kV. Transmission Line assets were allocated between overhead networks assets 33kV and above and underground networks assets 33kV and above.

Table 3.3.3 - Total disaggregated RAB asset values

Source of Data

These values are calculated by referencing the first and last row in each section of table 3.3.2.

Estimated or actual information

The value of capital contributions or contributed assets is materially dependent on and reconciles to our statutory accounts and very few assumptions are made in presenting in this variable. It is therefore considered to be actual information as defined by the RIN.

The overhead distribution assets (wires and poles) were calculated in accordance with the RIN requirements and are based on the estimated information in other templates. This information is not materially dependent on information from any of our systems or other records used in the normal course of business. Therefore, this information is defined by the RIN to be estimated information.

The Standard Lives is sourced from peer Comparison from Economic RIN benchmarking table 3.3.4 by peer for 2015-16 or 2016.

Methodology and assumptions

Table 3.3.3 presents a summary of the average of the opening and closing values by period for each of the Economic Benchmarking categories. These values are calculated by referencing the first and last row in each section of table 3.3.2.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the RIN requirements
Clause 5.6: Where the RAB includes capital contributions, capital contributions must be reported in the '3.3. Assets (RAB)' sheet. This data must be provided as a separate entry at DRAB13.	Capital contributions have been reported in the row labelled "DRAB13". The amounts reported in these rows are the "revenues" received as funding or gifted assets from an external party.
Clause 5.17: Total disaggregated RAB asset values: PWC must report average RAB asset values that have been disaggregated into the categories in this table. These must be calculated as the average of the opening and closing RAB values for the relevant regulatory year for each of the RAB asset categories and should be directly reconcilable to the opening and closing values in table 3.3.2 for the relevant categories.	We have provided average RAB values in table 3.3.3 which align with the opening and closing values in table 3.3.2. The methodology used for the calculation of these values is detailed below.

Table 3.3.4 - Asset lives

Source of Data

The information has been sourced as follows:

- RAB movements: RY06 to RY09 - UC: Po Adjustment Model FINAL (March 2009).xls
- RAB movements: RY10 to RY13- UC: 2014 NPD - Initial RP - Attachment 16 - RFM Commission preferred.xls
- RAB movements: RY14 - Proposal: [PWC - Remapped UC RFM - v2 - DRAFT - 30 June 2017.xlsx]
- RAB movements: RY15 to RY19 -Proposal: [PWC - Roll Forward Model - v7 - DRAFT - 21 August 2017.xlsm]
- Connection capex: Gross capex - Category Analysis RIN - Table 2.1.1
- Connection capex: Capital contributions - Category Analysis RIN - Table 2.1.7
- Circuit Length: Economic Benchmarking RIN - Table 3.5.1
- Circuit capacity MVA: Economic Benchmarking RIN – Table 3.5.1
- Standard lives – Peer comparison: Economic Benchmarking RIN – Table 3.3.4 by peer for 2016 or 2015-16 regulatory period

Estimated or actual information

All information in table 3.3.4 is based on the asset lives from other DNSPs. Therefore, it is not materially dependent on our systems or other business records and is, by definition, estimated information.

Methodology and assumptions

The estimated residual service lives have been calculated using an accounting proxy method. In general, the residual service life for each category is calculated by dividing the closing balance for the period by the straight-line depreciation value for the period. The values in forecast periods are expected to change as the ratio of closing balances to straight-line depreciation varies slightly year on year as forecast values are replaced with actual values.

The estimated service life of new assets by EB category has been calculated based on peer comparisons. The data in table 3.3.4 reflects the 2016 or 2015-16 regulatory reporting periods for 13 different peers.

We calculated a simple average for all populated cells, recognising that some peers did not have assets in certain Economic Benchmarking categories. The following table provides a summary of the data used to calculate the SCS lives. This approach was replicated for both network services and ACS standard lives by Economic Benchmarking category. These standard lives are not expected to change in future submissions of table 3.3.4.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with requirements
Clause 5.18: Workbook 2 – Economic benchmarking, regulatory template 3.3, table 3.3.4 Asset lives: (a) In relation to table 3.3.4.1 'Asset lives – estimated service life of new assets' and table 3.3.4.2 'Asset lives – estimated residual service life', PWC must report asset lives for all RAB assets in accordance with the definitions provided in the notice. (b) Where the categories comprise of a number of assets, asset lives for the whole category must be calculated by weighting the lives of individual assets within that category. Weightings must be calculated in order of preference.	We have complied with the AER's instructions as demonstrated in our methodology and assumptions.
Clause 5.19 (a) Equation 1 Weighted average asset life calculation: Weighted average asset life for assets in category $j = \sum_{i=1}^{n} \frac{x_{i,j}}{RC_j} . EL_{i,j}$ Where: *n* is the number of assets in category j $x_{i,j}$ is the value of asset i in category j $EL_{i,j}$ is the expected life of asset i in category j RC_j is the sum of the value of all assets in category j (b) For example, where the weightings are based on RAB shares or replacement costs, the weighted average asset life of each category may, for two assets, be calculated in the following manner: (i) If Category 1 contains 2 assets; Asset 1 has an expected life of 50 years and a value of $3 million; and Asset 2 has an expected life of 20 years and a value $2 million, then the weighted average asset life of assets in this category is 38 years: [(3/5) x 50] + [(2/5) x 20] = 38. (c) RAB is our preferred asset value measure for weighting but replacement cost is an acceptable proxy if disaggregation of the RAB to the relevant level is not	We have complied with the AER's instructions as demonstrated in our methodology and assumptions.

possible (and capacity shares are then a further proxy to replacement cost shares).	
Clause 5.20: Workbook 2 – Economic benchmarking, regulatory template 3.3, table 3.3.4.1 Asset lives – estimated service life of new assets: a. PWC must report the current expected service life of new assets in this table. The expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. (b)his may not align with the asset's financial or tax life.	We have developed estimated service life of new assets based on Peer comparisons as detailed in section 3.4.2 below.
Clause 5.21: Workbook 2 – Economic benchmarking, regulatory template 3.3, table 3.3.4.2 Asset lives – estimated residual service life: (a) PWC must report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409) will deliver the same effective service as that asset class did at its installation date.	The estimated residual service lives have been calculated using an accounting proxy method set out below.

Template - 3.4 Operational Data

Table 3.4.1 - Energy delivery

Source of Data

The two primary sources of information are MV90 and RMS. These datasets contain information on customer numbers, consumption, and export from PV. Calculations and assumptions have been applied to this source data.

Estimated or actual information

The information is both actual and estimated, as described below:

- Total Energy Delivery - This information is based on data from our systems and from external sources. Assumptions have been applied which may be of material value. Consequently, the RIN defines this data to be estimated information.
- Energy Delivery where time of use is not a determinant - This is based on our systems and records and does not contain any significant assumptions. Therefore, the RIN defines this information to be actual information.
- Energy Delivery at Shoulder times and Controlled load energy deliveries - We have entered zeros as we do not provide a shoulder period tariff or a controlled load service. Therefore, the information does not materially rely on any system or records and the RIN defines this to be estimated information.
- Energy Delivery at On-peak times and Energy Delivery at Off-peak times - This is based on our systems and records and does not contain any significant assumptions. Therefore, the RIN defines this information to be actual information.
- Energy Delivery to unmetered supplies - This information materially relies on data sourced externally and is therefore defined by the RIN as estimated information.
- Energy into DNSP network at On-peak times, Energy into DNSP network at Shoulder times & Energy into DNSP network at Off-peak times - We do not have this information and have reported zero. This information does not rely on our systems or records and is therefore defined by the RIN to be estimated
- Energy received from major generator and other DNSPs not included in the above categories - This information is sourced from our records without any significant assumptions applied. Therefore, the RIN defines this information to be actual information.
- Energy into DNSP network at On-peak times from non-residential embedded generation, Energy into DNSP network at Shoulder times from non-residential embedded generation and Energy into DNSP network at Off-peak times from non-residential embedded generation - We do not have this information and have reported zero. This information does not rely on our systems or records and is therefore defined by the RIN to be estimated information.

- Energy received from embedded generation not included in above categories from non-residential embedded generation - This information is sourced from our records without any significant assumptions applied. Therefore, the RIN defines this information to be actual information.
- Energy into DNSP network at On-peak times from residential embedded generation, Energy into DNSP network at Shoulder times from residential embedded generation & Energy into DNSP network at Off-peak times from residential embedded generation - We do not have this information and have reported zero. This information does not rely on our systems or records and is therefore defined by the RIN to be estimated information.
- Energy received from embedded generation not included in above categories from residential embedded generation - This information is sourced from our records without any significant assumptions applied. Therefore, the RIN defines this information to be actual information.
- Residential customers energy deliveries - This is based on our systems and records and does not contain any significant assumptions. Therefore, the RIN defines this information to be actual information.
- Non-residential customers not on demand tariffs energy deliveries - This is based on our systems and records and does not contain any significant assumptions. Therefore, the RIN defines this information to be actual information.
- Non-residential low voltage demand tariff customers energy deliveries and Non- residential high voltage demand tariff customers energy deliveries - This is based on our systems and records and does not contain any significant assumptions. Therefore, the RIN defines this information to be actual information.
- Other Customer Class Energy Deliveries - This information materially relies on data sourced externally and is therefore defined by the RIN as estimated information.

Methodology and assumptions

For 2017-18, we developed a customer number and energy consumption dataset that was collated from metering system (MV90) and billing systems (RMS). Certain data relating to remote communities was excluded because the remote community supply networks are not classified as "distribution services" for the purpose of the RIN and are therefore not regulated. This was done in two steps:

The data was restricted to only include customer installations in the Darwin - Katherine, Alice Springs and Tennant Creek regulated systems. There are 18 remote community networks that our regulated networks supply. Each of these remote communities are considered to be individual networks. Therefore, consumption for all installations was included but the community was treated as one single customer:

Only 17 of the 18 communities listed have consumption recorded during the 2017/18 period. There are no installations with the District Area Code D25. The dataset classified all consumption data with a customer type attribute as follows: PR – Private, PPM-Prepayment Meter, CO – Commercial, GO- Government, IN- Internal

As RMS is a live system, if the customer type changes during the period of analysis, data is provided for both customer types and installations with multiple customer types need to be reviewed. The customer type at the end of the analysis period and therefore the "current" customer type is what it is reported as.

MV90 provided the interval billed customer data which was supplied by Power Networks Metering monthly for all schedule A and B customers. Previous years RIN included Schedule C customers that were interval billed as they were in the report however as they have been removed from this report, their consumption is included in the

Below we have set out the methodology for each variable:

- Total Energy Delivery - Total Energy Delivery was calculated as the sum of the energy delivery variables in Table 3.4.1.1.
- Energy Delivery where time of use is not a determinant - This variable was completed from the energy consumption dataset described above, by summing the consumption of: all residential customers (customer types PR and PM) as there are no time of use network tariffs for residential customers and those non-residential customers (customers with consumer type CO, GO and IN) not on demand tariff or time of use tariff.
- Energy Delivery at Shoulder times & Controlled load energy - We do not have a shoulder period or controlled load services. Therefore, these variables have been reported with zeros.
- Energy Delivery at On-peak times & Energy Delivery at Off-peak times - The metering system data was used to identify which customers were billed on a time of use basis and their consumption. As noted above, this data does not include consumption of any residential customers as we did not have any time of use network tariffs for residential customers for the reporting period.
- Energy Delivery to unmetered supplies - Our unmetered consumption consists of traffic lights and from 2015-16, National Broadband Network (NBN) assets. Traffic lights data was provided by the NT Department of Infrastructure, Planning and Logistics. The data contained a list of assets, their addresses, upgrade date, associated equipment, type of globes used and their wattage. NBN unmetered assets were installed from December 2015 so there is only two years of customer number and consumption data. This information is collected internally when new NBN assets are created, the information includes the asset number, address and region and the wattage of each site. Annual unmetered usage in kWh for all unmetered installations was calculated as: (Water Hours per day x days per year)/1000
- Energy into DNSP network at On-peak times, Energy into DNSP network at Shoulder times & Energy into DNSP network at Off-peak times - We record a range of statistics on an annual basis in our Annual Internal Statistics workbook for a range of reporting purposes and general use. This contains records of the total energy received but not the energy received during specific time periods. These variables are therefore reported as zero.

- Energy received from major generator and other DNSPs not included in the above categories - Data for 2017-18 was provided by Market Operator business section of Power and Water based on Market Settlements data which is the amount of generated energy the Generator provided to the Retailer through the regulated network.
- Energy into DNSP network at On-peak times from non-residential embedded generation, Energy into DNSP network at Shoulder times from non-residential embedded generation and Energy into DNSP network at Off-peak times from non-residential embedded generation - We do not record energy received from embedded generation by time of generation. Therefore, these variables have been reported as zero values.
- Energy received from embedded generation not included in above categories from non-residential embedded generation - Photovoltaic (PV) export data was produced for all electricity installations located on regulated grids that were on a PV tariff. Remotely read interval meters show export consumption as a negative value and manually read PV meters give the export consumption as positive values. The values reported accounted for this to ensure the total energy received was reported. Finally, the customer type was used to extract only the non-residential customers' data. Energy received from generation facilities with a nameplate capacity below 1 MW is included in non-residential embedded generation customers.
- Energy into DNSP network at On-peak times from residential embedded generation, Energy into DNSP network at Shoulder times from residential embedded generation & Energy into DNSP network at Off-peak times from residential embedded generation - We do not record energy received from embedded generation by time of generation. Therefore, these variables have been reported as zero values.
- Energy received from embedded generation not included in above categories from residential embedded generation - PV export data was produced for all electricity installations located on regulated grids that were on a PV tariff. Remotely read interval meters show export consumption as a negative value and manually read PV meters give the export consumption as positive values. The values reported accounted for this to ensure the total energy received was reported. Finally, the customer type was used to extract only the residential customers' data.
- Residential customers energy deliveries - This variable was completed from the energy consumption dataset described above, as the consumption of all residential customers (customer types PR and PM) as we do not have any time of use network tariffs for our residential customers.
- Non-residential customers not on demand tariffs energy deliveries - This variable was completed from the energy consumption dataset described above, as the consumption of non-residential customer types (customer types CO, GO and IN) that use less than 750mwh per year (those customers on Schedule C network billing) that were not on demand tariff or time of use network tariffs.

- Non-residential low voltage demand tariff customers energy deliveries and Non-residential high voltage demand tariff customers energy deliveries - Low Voltage non-residential customers were identified from the MV90 interval billed customer report where the customer had a Schedule B network billing tariff. Schedule B tariff is for those customers that use over 750mwh per year but do not have HV meters (those with a meter rating of 4000 or higher). The annual consumption may change and therefore the schedule is changed throughout the year. High Voltage non-residential customers were identified as those on a Schedule A network billing tariff as they use over 750mwh per year and have a meter rating of 4000 or higher) There are 39 of these customers currently.
- Other Customer Class Energy Deliveries - After accounting for the other energy delivered data reported in Table 3.4.1.4 the only 'other' energy delivered is for unmetered supplies. Therefore, this data was reported from variable *Energy Delivery to unmetered supplies* in Table 3.4.1.1.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the RIN Requirements
Clause 6.1: Workbook 2 - Economic benchmarking, regulatory template 3.4, table 3.4.1 Energy delivery: (a) Energy delivered is the amount of electricity transported out of PWC's network in the relevant regulatory year (measured in GWh). It must be the energy metered or estimated at the customer charging location rather than the import location from the TNSP. Energy delivered must be actual energy delivered data, unless this is unavailable. Where actual information is not available for the most recent reporting period, energy delivery data for that period may be reported on an accrual basis. (b) Peak, shoulder and off-peak periods relate to PWC's own charging periods.	Energy delivered has been reported at the charging location based on amount billed. Energy delivered for the reporting period has been based on our peak, shoulder and off-peak periods applied for billing purposes. We do not have a shoulder period and shoulder periods have been reported as zero energy.
Clause 6.2: Workbook 2 - Economic benchmarking, regulatory template 3.4, table 3.4.1.1 Energy grouping - delivery by chargeable quantity: (a) PWC must report energy delivered in accordance with the category breakdowns as per the definitions provided in Appendix F. (b) PWC must only report 'Energy delivery where time of use is not a determinant' (DOPED0201) for energy delivery that was not charged for peak, shoulder or off-peak periods.	Table 3.4.1.1 reports energy delivered based on the categories as defined in Appendix F. We have reported Energy delivered where time of use is not a determinant (DOPED0201) for energy delivery that was not charged for peak, shoulder or off-peak periods. We do not have a shoulder period and shoulder periods have been reported as zero energy.

Clause 6.3: Workbook 2 - Economic benchmarking, regulatory template 3.4, table 3.4.1.2 Energy - received from TNSP major generators and other DNSPs by time of receipt: (a) PWC must report energy input into its network as measured at supply points from major generators and other DNSPs in accordance with the definitions provided in Appendix F.	Table 3.4.1.2 reports energy received based on the categories as defined in Appendix F.
6.3 (b) PWC must only report energy against 'Energy received from major generators and other DNSPs not included in the above categories' (DOPED0304) where it is not possible to allocate the energy received into on- peak, shoulder and off-peak times.	We have reported Energy received from major generators and other DNSPs not included in the above categories (DOPED0304) for energy delivery that was not charged for peak, shoulder or off-peak periods.
Clause 6.4: Workbook 2 - Economic benchmarking, regulatory template 3.4, table 3.4.1.3 Energy - received into PWC system from embedded generation by time of receipt: (a) Energy delivered must be reported in accordance with the category breakdown as per the definitions provided in Appendix F.	Table 3.4.1.3 reports energy received from embedded generators based on the categories as defined in Appendix F.
6.4 (b) PWC is required to report energy received from non- residential embedded generation by time of receipt. PWC is required to report back cast energy received from residential embedded generation only if it records data for these variables (DOPED0405-DOPED0408), however PWC is required to provide this data for future regulatory years.	We have reported Energy received from non-residential embedded generation by time of receipt
6.4 (c) 'Energy received from embedded generation not included in above categories' (DOPED0404 and DOPED0408) includes energy received from embedded generation on an accumulation basis and not measured by the time of receipt. PWC must only report energy received in DOPED0404 where it is not possible to allocate the energy received into on-peak, shoulder and off-peak times (DOPED0401-DOPED0403 and DOPED0405-DOPED0407).	The amounts we reported in Energy received from embedded generation not included in the above categories only includes amounts that could not be reported in the peak, should and off-peak times.
Clause 6.5: Workbook 2 - Economic benchmarking, regulatory template 3.4, table 3.4.1.4 Energy grouping - customer type or class (a) PWC must report energy delivered in accordance with the category breakdown as per the definitions provided in Appendix F. The category breakdown must be consistent with the customer types reported in table 3.4.2.1.	Table 3.4.1.4 reports energy based on the categories as defined in Appendix F. The categories have been reported consistently with those required in Table 3.4.2.1.

Table 3.4.2 - Customer numbers

Source of Data

Customer information data was sourced from RMS. Customer energy information was sourced from RMS and MV90. Data on location type (feeder data) was sourced from GIS and Maximo.

Estimated or actual information

This information in 3.4.2 is sourced from our RMS, MV90, GIS and Maximo systems. However the assumption about customer type classification not changing over time was required to create the data required in the RIN. As all variables in Template 3.4.2 depend on these assumptions and that a materially different outcome may arise using a different method, all information is defined by the RIN as estimated information.

Methodology and assumptions

For 2017-18, we developed a customer number and energy consumption dataset that was collated from metering system (MV90) and billing systems (RMS). Certain data relating to remote communities was excluded because the remote community supply networks are not classified as "distribution services" for the purpose of the RIN and are therefore not regulated.

Residential customer numbers have been reported as the number of customers (by NMI) that contributed to the energy reported in Template 3.4.1 and from the customer number and energy dataset described in the basis of preparation for Template '3.4.1 Energy Delivery'.

The number of non-residential customers not on a demand tariff has been reported as the number of customers (by NMI) that contributed to the energy reported in Template 3.4.1 and from the customer number and energy dataset described in the basis of preparation for Template '3.4.1 Energy Delivery'.

The number of low voltage connected customers has been reported as the number of customers (by NMI) that contributed to the energy reported in Template 3.4.1 and from the customer number and energy dataset described in the basis of preparation for Template '3.4.1 Energy Delivery'.

The number of high voltage connected customers has been reported as the number of customers (by NMI) that contributed to the energy reported in Template 3.4.1 and from the customer number and energy dataset described in the basis of preparation for Template '3.4.1 Energy Delivery'.

The number of customers with unmetered supplies has been reported as the number of customers that contributed to the energy reported in Template 3.4.1 and from the customer number and energy dataset described in the basis of preparation for Template '3.4.1 Energy Delivery'. Specifically, street lighting customers have been excluded in accordance with the RIN requirements. In contrast, the traffic light assets and NBN related assets have been reported as individual customers.

No other customers are known to exist and therefore this variable has been reported as zero.

We do not collect customer numbers by network location as required by the RIN. The customer numbers by location variables were calculated by apportioning the total billed customers from Table 3.4.2.1 using customer connection data from GIS and Maximo. The driver for the proportions was the percentage of connections on each feeder and feeder location type (urban, CBD, rural and long rural).

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with requirements
6.6 (a) Distribution *customers* for a *regulatory year* are the *average* number of active National Meter Identifiers (*NMIs*) in *PWC*'s *network* in that year (except for *unmetered customer numbers*). Each *NMI* is counted as a separate *customer*. The *average* is calculated as the *average* of the number of *NMIs* on the first day of the *regulatory year* and on the last day of the *regulatory year*. Both energised and de-energised *NMIs* must be counted. Extinct *NMIs* must not be counted.	We have captured all active customer connections, being those that are energised and de-energised but not those that are extinct. Customer numbers have been counted based on NMIs so each NMI is a customer.
6.6 (b) For unmetered *customers*, the *customer numbers* are the sum of *connections* (excluding public lighting *connections*) in *PWC's network* that do not have a *NMI* and the energy usage for billing purposes is calculated using an assumed load profile (examples include bus shelters, security lighting and traffic signals where not metered). Public lighting *connections* must not be counted as unmetered *customers*.	We have not counted street lighting assets as individual customers. However, NBN and traffic signals have been counted as individual customers for each connected.
6.7 (a) *PWC* must report *customer numbers* in accordance with the categorisation as per the definitions provided in Appendix F.	We have reported *customer numbers* in accordance with the definitions provided in Appendix F of the RIN.
6.7 (b) *PWC* must report *customers* against 'Other *customer numbers'* (DOPCN0106) only when *customers* cannot be allocated to the other *customer* classes (DOPCN0101-DOPCN0105).	*We* have reported *customers* against 'Other *customer numbers'* (DOPCN0106) only when *customers* could not be allocated to the other *customer* classes (DOPCN0101-DOPCN0105).
6.8 (a) *PWC* must report *customer numbers* in accordance with the category definitions provided in Appendix F. The locations are: *CBD*, *urban*, *short rural* and *long rural.*	*We* have reported *customer numbers* in accordance with the definitions provided in Appendix F of the RIN.

Table 3.4.3 - System demand

Source of Data

The following information was sourced from SCADA and Meter data, together with Bureau of Meteorology (BOM) weather data. We have also used MV90 for extracting maximum demand for High Voltage (HV) and Low Voltage (LV) customers.

Estimated or actual information

The MVA values for template 3.4.3.3 are considered actual information as they are directly calculated from information from our SCADA system. The MW values calculated in 3.4.3.1 were converted from MVA using the average Zone Substation power factors and would not result in materially different values if an alternative method was used. For this reason the data is defined as actual.

POE 50 and POE 10 weather corrected maximum demand values were calculated using actual maximum demand data and the maximum temperatures retrieved from Bureau of Meteorology website. The weather corrected maximum demand data is actual information, as the maximum temperature data from BOM website is routinely downloaded and stored in our internal record keeping system “RM8”.

The calculations for Average overall network power factor conversion between MVA and MW, and Average power factor conversion for 66kV and 132 lines have been based on the calculation in the RIN. For Average power factor conversion for 11kV & 22kV, we also used the RIN calculation, except we excluded the some feeders from the calculation due to corrupted SCADA data: We consider these exceptions do not result in materially different outcomes, and therefore the information provided is still actual.

The measured maximum demand variable is defined by the RIN to be actual information because it is materially dependent on our metering system data.

Methodology and assumptions

For all tables, we reported the information required for our three networks (Darwin-Katherine, Alice Springs and Tennant Creek systems) as if they were a single interconnected system.

Zone substation

For each zone substation in Darwin-Katherine, Alice Springs and Tennant Creek systems, the raw adjusted (switching normalised) demand values in MVA from SCADA and metering data were summated at fixed time intervals for each reporting year. The fixed time intervals were dependent on available data but no more than one-hour interval.

The annual coincident maximum demand in MVA was calculated as the maximum of these summated values for each fixed time interval over the year. The non-coincident maximum demand in MVA was calculated as the sum of the largest recorded demand for each zone substation regardless of the time interval.

The method of adjusting for switching transfers only uses MVA values. As such the MW values are calculated using the average Zone Substation power factors. Where MVA data was unavailable MW data was used. Where MW data was not available then MVA or MW data from a point one level higher in the system was used. For Example, Center Yard Zone Substation did not have data so information was taken from the 66kV connection point from the Darwin Zone Substation.

Generation Connection Point

The annual coincident maximum demand in MVA was calculated as the maximum of these summated values for each fixed time interval over the year. The non-coincident maximum demand in MVA was calculated as the sum of the largest recorded demand for each generation connection point.

The annual coincident maximum demand in MW was calculated as the maximum of these summated values for each fixed time interval over the year. The non-coincident maximum demand in MW was calculated as the sum of the largest recorded demand for each generation connection point.

Weather correction

The Northern Territory has very different weather conditions to the rest of Australia. It experiences only two seasons every year – wet season and dry season, not the traditional four seasons experienced by the other States. There is no correlation between system demand and weather in the dry season (April to October) for Darwin. Therefore, weather correction is only valid in the wet season (November to March). For this reason, the maximum demand on our networks is expected to only occur during the wet season and our data is based on wet season demand data.

We use weather data obtained from the following Bureau of Meteorology weather stations.

- Darwin Airport weather station for Darwin-Katherine system
- Alice Springs Airport weather station for Alice Springs system
- Tennant Creek Airport weather station for Tennant Creek system

We undertake weather correction based on the difference between the daily maximum temperature for the region/system and the assumed POE 50% and POE 10% temperatures. This is based on studies of the correlation between temperature increase in each region and the demand increase in that same region.

For all zone substations, we undertake weather correction for every raw adjusted demand in MVA for every interval of the year. Then using the weather corrected demand values, we calculate the non-coincident and coincident MVA maximum demands consistently with the raw unadjusted maximum demand data. For the same reason as the actual MW, the weather corrected maximum demand values in MW were calculated using the weather corrected values in MVA and the average Zone Substation power factors.

For all generation connection points, we undertake weather correction for every raw unadjusted demand in MVA for every interval of the year. Then using the weather corrected demand values, we calculate the non-coincident and coincident MVA maximum demands consistently with the raw unadjusted maximum demand data. Then using the weather corrected demand values, we calculate the non-coincident and coincident MW maximum demands consistently with the raw unadjusted maximum demand data.

Power Factor conversion

The average overall power factor was calculated using the summated MW divided by summated MVA at the system (generation) level. All data for these calculations was extracted from SCADA/meter data as follows:

- The average power factors for 11 kV and 22 kV lines were calculated using the summated MW divided by summated MVA. All data for these calculations was extracted from SCADA/meter data.
- The average power factor for 66kV lines was based on the power factor at the 'injection points' rather than at each individual 66kV line because both MVA and MW data for 66kV lines was not available. The power factor at the injection points was calculated using the summated MW divided by the summated MVA. The source data for these calculations is SCADA/meter data.
- The average power factor for 132kV lines was based on MVA and MW values at the injection ends of the 132kV line (i.e. Channel Island Power Station, Katherine Power Station and Pine Creek Power Station). The source data for these calculations is SCADA/meter data.

High Voltage and low voltage customers

We extracted the maximum demand for HV and LV customers on a demand tariff from our metering system, MV90. This demand record was the basis for the customer bills where a demand tariff was applicable.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with requirements
Clause 6.9 (a): Tables 3.4.3.1 to 3.4.3.4 must be completed in accordance with the definitions in Appendix F. PWC must provide inputs for these cells if it has calculated historical weather adjusted maximum demand.	We have applied the definitions in Appendix F and inputted these cells where it has calculated historical weather adjusted maximum demand.
Clause 6.9 (b): Where PWC does not calculate weather adjusted maximum demands it may estimate the historical weather adjusted data.	We calculate the weather adjusted maximum demands. As this data is calculated with data obtained

	outside of our systems, it is considered estimated based off RIN definitions.
Clause 6.10: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.1 Annual system maximum demand characteristics at the zone substation level – MW measure: Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% probability of exceedance levels.	For the zone substation level MW in template 3.4.3.1, We have reported the actual raw demands (not weather normalised) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand as per Methodology and Assumptions section.
Clause 6.11: Economic benchmarking workbook, regulatory template 3.4, table 3.4.3.2 Annual system maximum demand characteristics at the generator connection point level - MW measure: (a) Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	For the generation connection point level MW in template 3.4.3.2, We have reported the actual raw demands (not weather normalized) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand as per Methodology and Assumptions section.
Clause 6.12: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.3 Annual system maximum demand characteristics at the zone substation level – MVA measure: Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	For the zone substation level, we have reported the actual raw demands (not weather normalised) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand in template 3.4.3.3.
Clause 6.13: Economic benchmarking workbook, regulatory template 3.4, table 3.4.3.4 Annual system maximum demand characteristics at the generator connection point - MVA measure (a) Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	For the generator connection point level, we have reported the actual raw demands (not weather normalised) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand in template 3.4.3.4.
Clause 6.14: Economic benchmarking, regulatory template 3.4, table 3.4.3.5 Power factor conversion between MVA and MW: 1. PWC must report the power factor to allow for conversion between MVA and MW measures for each voltage. If both MVA and MW throughput for a network are available then the power factor is the total	Power factor has been calculated following the total MW divided by total MVA requirements as per Methodology and Assumptions section.

MW divided by the total MVA. PWC must provide a power factor for each voltage level and for the network as a whole. The average overall power factor conversion (DOPSD0301) is the total MW divided by the total MVA. (b) If either the MW or MVA measure is unavailable the average power factor conversion can be calculated as an approximation based on best engineering estimates.	
6.15(a) PWC is only required to complete this table if it charges customers for maximum demand supplied. If PWC does not charge customers on this basis then PWC should enter '0'. (b) PWC must report maximum demand amounts for customers that are charged based upon their maximum demand as measured in MW. Where PWC cannot distinguish between contracted and measured maximum demand, demand supplied must be allocated to contracted maximum demand.	We do not charge customers by MW and have entered zero for this table. We measure the monthly maximum demand for customer on an MVA tariff. We have entered all maximum demand into the measured maximum demand variable.
6.16(a) PWC is only required to complete this table if it charges customers for demand supplied. If PWC does not charge customers on this basis then PWC must enter '0'. 6.16(b) PWC must report maximum demand amounts for customers that are charged based upon their We do not apply a contracted maximum demand tariff, so that variable has been entered as zero. (b) PWC must report maximum demand as measured in MVA. Where PWC cannot distinguish between contracted and measured maximum demand, demand supplied must be allocated to contracted maximum demand.	We can distinguish between contracted and measured demand.

Template - 3.5 Physical Assets

Table 3.5.1 - Network capacities

Table 3.5.2 - Transformer capacities

Table 3.5.3 - Public lighting

Source of Data

The data has been sourced as follows

- Cable and Conductor Ratings – We have used the Sincal database extract.
- Asset Age Profile – We have used the same sources as the Category Analysis RIN (template 5.2)
- HV Customer Installed Capacity - We have used HV customers installed capacity and estimated opex
- Cold Spare Capacity - Extracted from Maximo
- Transformer capacities Power and Water Corporation - Network Management Plan 2015-16 - January 2017 information update and Power and Water Corporation - Network Management Plan

Estimated or actual information

The information provided is both actual and estimated.

- Information in templates 3.5.1.1 and 3.5.1.2 is actual as defined by the AER's RIN. The quantities of cables and conductors are taken directly from our asset system.
- Information in template 3.5.1.3 and 3.5.1.4 is estimated as defined by the AER's RIN. There is insufficient detail in our asset management system (Maximo) on cable assets to determine the precise cable ratings in all cases. As such, some assumptions were made to determine the most likely cable ratings. Alternative assumptions may have resulted in materially different outcomes.
- The capacity owned by HV Customers information in template 3.5.2 is estimated as defined by the AER's RIN. We do not record the capacity of customer-owned distribution transformers. Therefore, these have been estimated using best endeavours. Alternative assumptions may result in materially different outcomes and therefore the data should be considered an estimate.
- Information on transformer capacities is sourced from our Network Management Plan and its updates. These are business record so information is defined as "actual".

Methodology and assumptions

We used the following methodologies for each variable:

- Circuit length - The circuit lengths were taken from the Asset Age Profile dataset as described in the Category Analysis Basis of Preparation for Template 5.2 Asset Age profile. Underground network circuit length at each voltage – The method was the same as for circuit cables except that the cable dataset was used in place of the conductor.
- Estimated overhead network weighted average MVA capacity by voltage class - To calculate the weighted average MVA for overhead conductors, first the current carrying capacity of each conductor type was identified using standard drawings, planning documentation and manufacturers catalogues. The list of conductors with conductor type, length, voltage and installation date were taken from the Asset Age Profile dataset as described in the Category Analysis Basis of Preparation for template 5.2 Asset Age profile. Each conductor was assigned an "MVA meter" value by multiplying the calculated MVA capacity by the length of the conductor.
- Estimated underground network weighted average MVA capacity by voltage class - The weighted average MVA capacity for underground cables was calculated in a similar manner to the overhead conductors. The list of cables with cable insulation, conductor type, length, voltage and installation date were taken from the Asset Age Profile dataset as described in the Category Analysis Basis of Preparation for template 5.2 Asset Age profile. Each cable was assigned a "MVA meter" value by multiplying the calculated MVA capacity by the length of the cable. The weighted average MVA for each voltage level was then calculated.
- Transformer Capacities - Distribution Transformer Total Installed Capacity The distribution transformer capacity owned by utility was also taken from the Asset Age Profile dataset as described in the Category Analysis Basis of Preparation for template 5.2 Asset Age profile. A small number of distribution transformers have unknown capacity. These were allocated an average capacity and included in the calculation of total installed capacity. The distribution capacity owned by HV customers is not recorded in our systems and had to be estimated. It was calculated by first extracting a list of HV customers from the Retail Management System. The transformer capacity of each customer was estimated by dividing their peak load by the average utilisation. The sum of the resulting installed capacities was used to populate template 3.5.2. We do not have any distribution transformer cold capacity. The spare capacity was calculated by summing the capacity of spare distribution transformers in stores.
- Transformer Capacities – For zone substation transformer capacity, the name plate of transformers at Subtransmission Substations and Zone Substations were taken into account as transformer capacities. The transformer capacities were sourced from the Network Management Plan 2015-2016. The cold spare capacity of Zone Substation transformers were added to the total Zone Substation transformer capacity. The cold spare capacities were obtained from the document "17-18 Cold Spare Capacity".
- Public Lighting - The responsibility for public lighting services has been transferred to local councils and the Framework and Approach paper did not classify public lighting as SCS or ACS. Therefore we have no public lighting information to report and have entered zeros for this template.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
7.1 (a) PWC must report against the capacity variables for its whole network. In this context the network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. Network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	The following have been excluded from the volumes, in accordance with the instructions: ▪ Services ▪ Protection, communications and control cables ▪ Streetlight cables and conductors ▪ Cables and conductors in unregulated areas
7.1 (b) For 'Other overhead voltages' and 'Other underground voltages' PWC must add additional rows for voltages other than: low voltage distribution;11 kV; SWER (single wire earth return) (applicable to overhead only); 22 kV; 33 kV; 66 kV; and132 kV.	We have no other voltages than those specified.
7.1 (c) PWC must specify the voltage for each 'other' voltage level.	We have no other voltages than those specified.
7.2 In relation to table 3.5.1.1 'Overhead network length of circuit at each voltage' and table 3.5.1.2 'Underground network circuit length at each voltage', circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three- phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.	Circuit length has been calculated from the GIS, which does not take into account vertical components such as sag. Each cable or conductor counts as one line regardless of the number of phases.
7.3 In relation to table 3.5.1.3 'Estimated overhead network weighted average MVA capacity by voltage class' and table 3.5.1.4 'Estimated underground network weighted average MVA capacity by voltage class', PWC must provide estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant.	The values provided are based on the planning ratings where available, and from detailed design ratings or OEM manuals otherwise.
7.4 This information will be used to calculate an overall MVA x km 'carrying capacity' for each voltage	Noted but not applicable to 3.5.1.4.

class under normal circumstances. PWC is required to provide summer maximum demands for summer peaking assets and winter maximum demands for winter peaking assets. If PWC's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for years where there was a summer peak.	
7.5 Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, PWC may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	This does not apply to our circumstances.
7.6 (a) PWC must report total installed distribution transformer capacity in this table. The total installed distribution transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g 132 kV or 66 kV to the 22 kV or 11 kV distribution level).	The distribution transformer capacity has been reported as instructed.
7.6 (b) This measure includes cold spare capacity of distribution transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Cold spare capacity has been calculated for DPA0503 and included in DPA0501 as required.
7.6 (c) Report transformer capacity owned by PWC; give nameplate continuous rating including cooling.	The transformer capacity has been reported as instructed.
7.6 (d) Report the transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage.	This figure has been estimated as described above.
7.6 (e) If the transformer capacity owned by customers connected at high voltage is not available, report summation of individual maximum demands of high voltage customers whenever they occur (i.e. the summation of single annual maximum demand for each customer) as a proxy for delivery capacity within the high voltage customers.	HV customer transformer capacity is not available. In order to estimate transformer capacity and HV customer opex for template 3.2, we have estimated the HV customer transformer quantities and capacities as described above.
7.6 (f) When completing the templates for regulatory years subsequent to the 2013 regulatory year, if PWC can provide actual information for distribution transformer capacity owned by high voltage customers it must do so; otherwise PWC must provide estimated information.	Estimated information has been provided as described above.

7.6 (g) Report the total capacity of spare transformers owned by PWC but not currently in use.	Spare capacity has been reported as instructed.
7.7 Economic benchmarking workbook, regulatory template 3.5, table 3.5.2.2 Zone Substation transformer capacity: (a) Report transformer capacity used for intermediate level transformation capacity in either one or two steps. For example, high voltages such as 132 kV, 66 kV or 33kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6kV.	Transformer capacity has been reported as instructed.
7.7(b) These measures must be the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included) and include both energised transformers and cold spare capacity. Assigned rating must be, if available the rating determined from results of temperature rise calculations from testing. Otherwise report the nameplate rating. For those zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders should be reported instead of transformer capacity.	Transformer ratings have been based on maximum nameplate rating, or where there has been a thermal capacity restraint.
7.7(c) "Total installed capacity for first step transformation where there are two steps to reach distribution voltage" (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or 11 kV where there will be a second step transformation before reaching the distribution voltage. This variable is only relevant where PWC has more than one step of transformation, if this is not the case PWC must enter '0' for this variable.	Template DPA0601 has been completed with transformer capacity reported as instructed and considers the first transformation step at sites where there are two steps to reach distribution voltage. 132 kV is the reference voltage where the transformation commences in Darwin Katherine System. 66kV is the reference voltage where the transformation commences in Alice Springs System. 11kV is the reference voltage where the transformation commences in Tennant Creek System.
7.7 (d) For "Total installed capacity for second step transformation where there are two steps to reach distribution voltage" (DPA0602) report total installed capacity where a second step transformation is applied before reaching the distribution voltage. For example 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within PWC's system. This variable is only relevant where PWC has more than one step of transformation, if this is not the case PWC must enter '0' for this variable.	Template DPA0602 has been completed with transformer capacity reported as instructed and considers the second transformation step at sites where there are two steps to reach distribution voltage. Palmerston Zone Substation transformer (11/22 kV) and Pine Creek Zone Substation transformer (22/11 kV) are included into DPA0602 category even though they are third step transformation to reach distribution voltage, as there is no category available for third step transformation in AER tables.
7.7 (e) For "Total zone substation transformer capacity where there is only a single transformation to reach distribution voltage" (DPA0603) report total	Transformer capacity has been reported as instructed for single step transformation sites as stated in 7.7 (c) and 7.7 (d) sections.

installed capacity where only a single step of transformation is applied before reaching the distribution voltage. This variable is only relevant where there is only a single step of transformation to reach distribution voltage. If there is more than one step of transformation to reach distribution voltage, the relevant capacities must be reported in DPA0601 and DPA0602.	
7.7 (f) For 'Total zone substation transformer capacity' (DPA0604) report the overall total zone substation capacity regardless of whether one or two steps are used to reach the distribution voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.	Total zone substation capacity has been reported as the sum of all zone substation transformers reported in DPA0601, DPA0602, DPA0603 and DPA0605.
7.7 (g) For 'Cold spare capacity of zone substation transformers included in DPA0604' (DPA0605), report total cold spare capacity included in total zone substation transformer capacity.	Spare capacity has been reported as instructed.

Template - 3.6 Quality of Service Data

Table 3.6.1 - Reliability

Source of Data

Outage data was sourced from the Asset Management System (Maximo).

The number of customers in NT was sourced from the Retail Management System (RMS) and the number of customer affected by the interruption was sourced from GIS/ESRI. For feeders and distribution substations, the customer count from GIS/ESRI was then loaded into Maximo.

The interruptions associated with Cyclone Marcs were recorded in the Cyclone Response System (CRS).

Estimated or actual information

The template includes both actual and estimated information.

- Unplanned outages are reviewed monthly whereas planned interruptions are not reviewed. Hence, the data on unplanned outages are actual whereas data on planned outages is considered to be estimated.
- There were interruptions where some NMI-type locations are recorded many times in Tropical Cyclone Marcus data and only the interruption having the longest duration was included in the final outage dataset. This assumption resulted in the data in both Templates 3.6.1 and 3.6.2 is estimated data.
- The source data on outages is contained in the Asset Management System (Maximo). Though additional processing of Maximo data was done to address regulatory requirements related to unplanned interruptions and to derive some additional values that are not contained in the sourced data, these additional processing was based on actual data obtained outside Maximo. Since the planned interruptions are included in all the data that is intended to address the intent of this requirement, the data in this templated is estimated.
- For 2017-18 financial year, the method used to calculate the energy not served was improved due to availability of good quality data. In the 2017-18 calculation the average load of the affected feeder per month was used whereas in the 2016-17 the average load per customer in each region was used. The change in the calculation method has not resulted in any significant change in the results.

Methodology and assumptions

Outage data

System operators record outages manually into Maximo in real time. The data recorded comes from various sources including SCADA, customer calls, outcome from monthly data reviews. The recorded on unplanned interruptions data is reviewed monthly by both System Control and Power Networks personnel to ensure that it is as accurate as possible based on the limitations of the systems used to capture this data. Data on planned outages is not reviewed and therefore the quality of data is poor.

It should be noted that for reliability reporting purposes, all the analysis is done in an excel spreadsheet file and the reliability indices (SAIDI/SAIFI) that are calculated only apply to regulated areas of the network. These indices were calculated after excluding some interruptions together with any duplicated interruptions.

There are some interruptions recorded on some assets that result in healthy assets being interrupted. For the sake of recording all outages affecting the customer, the first interruption is recorded as the parent event and the other related interruptions are recorded as child events. If all outages in the parent-child relationship were to be included in the reliability calculations, this would result in the reliability data being overestimated. Hence, for reliability calculations, all the parent events are excluded from those outages that are in the parent-child relationship. The data included Date of event, Time of interruption, Asset ID, Average duration of sustained customer interruption.

Number of customers affected

In most cases the outage-related data was used to provide the 'Number of customers affected by the interruption' as required in the RIN. However, in cases where these data were not provided, the customer count on an asset affected by the outage was obtained from GIS/ESRI. This was usually the case where the location that was interrupted is a switch, recloser, or pole fuses.

To calculate the SAIDI/SAIFI impact of an outage event, the 'Number of customers affected by the interruption' together with the 'Average duration of sustained customer interruption' was obtained directly from the outage record. The other input required is the number of customers base in NT. The customer base that was used is the total number of customers in the regulated areas of NT. This total number of customers was obtained from the Retail Management System (RMS) on a monthly basis. The number of customers used for the calculation is the 12-month rolling average of this monthly data.

The customer count on individual feeder was obtained from the GIS/ESRI on a quarterly basis and saved into excel spreadsheet file. These excel spreadsheet files are used as the source of the customer count on feeders and in feeder categories. The customer count on feeder categories was taken to be the average of the customer counts collated quarterly. The customer count data collated quarterly was also used to populate customer count on locations such as switches, reclosers, and pole fuses.

Major event days

For the purpose of calculating the Major Event Days, the Power and Water network is divided into three systems, namely: Darwin-Katherine, Alice Springs and Tennant Creek. The MEDs were identified by using the 2.5 Beta Method described in IEEE Standard 1366 as follows:

- When calculating the MEDs for 2017/18, all the days that have been identified as MEDs in the previous years together with other failure causes described in Clause 3.3(a) STPIS were excluded from the analysis before calculating the MEDs, e.g. When calculating the MEDs for 2017/18, the data analysed excluded all the days that have been identified as MEDs in the previous 5 years (2016/17- 2012/13);
- The Major Event Day Thresholds (TMED) were then identified for each of the three systems - The Tennant Creek system breached the threshold limit on 29 October 2017 because of the fault that was caused by the auxiliary transformer failure. The Darwin network exceeded the MED threshold on 17 March 2018 because of Tropical Cyclone Marcus.
- Any daily SAIDI value that exceeded the MED thresholds in d) was considered to be an MED and used in the AER submissions.

Cyclone Marcus

Darwin was hit by Tropical Cyclone March on the 17th March 2018. The interruptions associated with the cyclone were recorded in the Cyclone Response System (CRS) and thereafter exported into excel spreadsheet file. These outages were categorised into outages affecting HV assets (distribution substations) and those affecting individual customers were recorded on NMI-type locations. The outages on HV assets are used in the reliability data without changed. Where different outage end times exist, the latest date/time was used.

The outages recorded on NMI-type locations were handled as follows:

- Customer events having no related HV events were included in the final outage dataset using the assumption that their start time was 17 March 2018, around 09:08 AM. The actual end time of these outages was recorded in the Cyclone Response System (CRS).
- Where the NMI-type location is duplicated with various outage locations, only the interruption that lasted for the longest duration was included in the final outage dataset

Reasons for excluding some cyclone-related outages recorded on customer installations

- Some outages recorded on customer installations were traced/linked to an HV event which has no relevant details such as outage start/end date/time
- Some NMI-type locations are recorded many times and only the interruption having the longest duration was included in the final outage dataset

All the outages recorded on customer installations were recorded on the NMI-type location using the address provided in the outage record.

The outages obtained using the above process were merged with those already recorded in Maximo and cleansed - All the Maximo outages recorded in Darwin on the overheard network between 17 March 2018 around 09:00AM and 27 March 2018 at 12:00PM were considered to be duplicates and are excluded from any SAIDI/SAIFI calculation

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the RIN requirements
8.1(a) Reliability data must be reported in accordance with the definitions provided in the AER's STPIS unless otherwise specified.	The information provided by PWC is consistent with the requirements and associated definitions.
8.1(b) For the purposes of calculating reliability, an interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premises. The customer interruption starts when recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. Subsequent interruptions caused by network switching during fault finding are not to be included: An interruption ends when supply is again generally available to the customer.	Customer interruption data that is used to address the intent of this requirements is recorded manually by System control personnel there are some data quality related issues when recording the events having a duration that is less than one minute. There available infrastructure is also not able to assist in recording events that are less than one minute in duration. Hence, in order to improve on the quality of data provided in the AER submissions, PWC has interpreted sustained outages as those having a duration of at least one minutes.
8.1 (c) An unplanned interruption is an interruption due to an unplanned event. An unplanned event is an event that causes an interruption where the customer has not been given the required notice for the interruption or where the customer has not requested the outage.	PWC defined unplanned outages as any outage where the customer was not given at least 2 days' notice before the interruption
8.1(d) Excluded outages are defined in Appendix F.	PWC excluded interruptions described in Clause 3.3 (a) and (b) of the STPIS
8.2 (a) Reliability information in tables 3.6.1.1 and 3.6.1.2 is only to be reported for unplanned interruptions. Unplanned interruptions are as defined in the STPIS.	The outage data recorded by PWC is consistent with this AER requirement
8.2 (b) Whole of network SAIDI and SAIFI is the system wide SAIDI and SAIFI. We do not require SAIDI and SAIFI for individual feeder categories within PWC's network.	This is the sum of SAIDI/SAIFI values associated with all unplanned events with planned events, faults internal to customer premises, and cancelled events being excluded. This is calculated using the customer minutes lost and the total customer base in the regulated areas of NT
8.3(a) and 8.4(a) Report SAIDI and SAIFI in accordance with the definitions provided in Appendix F.	The outage data recorded by PWC is consistent with this AER requirement

8.4(b) The MED threshold must be calculated for the 2017 regulatory year in accordance with the requirements in the STPIS. The MED threshold calculated for 2016 must then be applied as the MED threshold for regulatory years prior to 2016 for the purpose of calculating SAIDI and SAIFI exclusive of MEDs as per the STPIS.	The MED calculations performed are in line with this AER requirement, as described below
8.5(a) Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions.	This was considered to be the energy not supplied to customers due to unplanned interruption after the allowed exclusions described in Clause 3.3 (a) of the STPIS
8.5(b) PWC must estimate the raw (not normalized) energy not supplied due to unplanned customer interruptions based on average customer demand (multiplied by the number of customers interrupted and the duration of the interruption). Average customer demand must be determined from (in order of preference): ▪ average consumption of the customers interrupted based on their billing history; ▪ feeder demand at the time of the interruption divided by the number of customers on the feeder; ▪ average consumption of customers on the feeder based on their billing history; 4average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder.	PWC used SCADA data to estimate the average feeder demand for each month. This value was then used as one of the inputs into the energy not supplied calculations
8.5 (c) Energy not supplied should be reported exclusive of the effect of excluded outages as defined in Appendix F.	The energy not supplied calculations are consistent with this AER requirement

Table 3.6.2 - Energy not supplied

Source of Data

The reliability data described in template 3.6.1 (Reliability) of the Economic Benchmarking RIN was the primary input for into template. This was originally sourced from Maximo, GIS/ ESRI and RMS as described in the basis of preparation for template 3.6.1. In addition, we used SCADA data to provide the data.

Estimated or actual information

The template includes both actual and estimated information.

- Unplanned outages are being reviewed monthly whereas planned interruptions are not reviewed. Hence, the data on unplanned outages can be considered to be actual whereas data on planned outages is considered to be estimated.
- As described in the "Data Source" section, there were interruptions where some NMI-type locations are recorded many times in Tropical Cyclone Marcus data and only the interruption having the longest duration was included in the final outage dataset. This assumption resulted in the data in Template 3.6.2 being estimated data.

Methodology and assumptions

The reliability data described in template 3.6.1 (Reliability) was used as the main input into this template . Other data was obtained from SCADA.

SCADA can record feeder demand every 30 minutes. These data were collated for the 2017-18 financial year and the average feeder demand was calculated for each month in 2017-18. This average demand was then used as one of the inputs into the energy not supplied calculation. Using the duration of an outage, the customers affected by the outage together with the demand per customer on a feeder the energy not supplied due to each outage was calculated as all the relevant events were added to obtain the value required in the RIN.

It should be noted that for 2017-18 financial year, the method used to calculate the energy not served was improved due to availability of good quality data. In the 2017-18 calculation the average load of the affected feeder per month was used whereas in the 2016-17 the average load per customer in each region was used. The change in the calculation method has not resulted in any significant changes in the results.

It should be noted that the energy lost calculation took into account all the exclusions allowed in line with Clause 3.3 (a) of the STPIS.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
8.5 (a) Energy not supplied is an estimate of the energy that was not supplied as a result of *customer interruptions*.	This was considered to be the energy not supplied to customers due to unplanned interruption after the allowed exclusions described in Clause 3.3 (a) of the STPIS
8.5 (b) *PWC* must estimate the raw (not normalized) energy not supplied due to unplanned *customer interruptions* based on *average customer* demand (multiplied by the number of *customers* interrupted and the duration of the *interruption*). *Average customer* demand must be determined from (in order of preference): 1. average consumption of the customers interrupted based on their billing history; 2. feeder demand at the time of the interruption divided by the number of customers on the feeder; 3. average consumption of customers on the feeder based on their billing history; 4. average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder.	PWC used SCADA data to estimate the average feeder demand for each month. This value was then used as one of the inputs into the energy not supplied calculations
8.5 (c) Energy not supplied should be reported exclusive of the effect of excluded outages as defined in Appendix F.	Energy not supplied was calculated after excluding all the allowed exclusions in line with Appendix F, which is consistent with this AER requirement

Table 3.6.3 - System losses

Source of Data

The data relates to information provided in template 3.4 of the Economic Benchmarking RIN. Please refer to our basis of preparation to identify the source for each variable identified in our methodologies and assumptions.

Estimated or actual information

The information is estimated as defined by the AER's RIN. The equation contains variables, which are identified as estimates in our response to template 3.4. Therefore, the resulting data is also an estimate.

Methodology and assumptions

We have used the equation in the AER's RIN to report the data. The formula is:

- System Losses = Energy Lost / Total Energy Received
- Energy Lost = electricity imported - electricity delivered, where:
- Electricity imported = "Energy received from TNSP and other DNSPs not included in the above categories" (template 3.4.1.2); plus Variable "Energy received from embedded generation not included in above categories from non-residential and residential embedded generation" (template 3.4.1.3)
- Electricity Delivered = "Total energy delivered" (template 3.4.1.)
- Total Energy Received = Electricity imported (calculated as per above)

Please see our response to template 3.4 for a description of the source data.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E of the RIN	Consistency with requirement
8.6 (a) System losses is the proportion of energy that is lost in distribution of electricity to PWC customers.	We have complied with this requirement.
8.6 (b) PWC must report distribution losses calculated as per Equation 2: System losses= (electricity imported-electricity delivered)/(electricity imported)×100	We have used this equation

Table 3.6.4 - Capacity utilisation

Source of Data

Overall utilisation was sourced from two internal records – "Power and Water Corporation - Network Management Plan 2015-16 - January 2017 information update" and "Power and Water Corporation - Network Management Plan for 2013-14 - 2018-19."

Estimated or actual information

The data is sourced from internal business records and systems, and so meets the definition of "actual" in the RIN.

Methodology and assumptions

The capacity utilisation values were calculated based on the summation of non-coincident maximum demands at sub-transmission substations and zone substations divided by the total transformer capacities in service. The transformer capacities and the maximum demand values were sourced from the Network Management Plan 2015-2016.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the RIN requirements
8.7 Economic benchmark workbook, regulatory template 3.6, table 3.6.4 Capacity utilisation: Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year.	We have applied this definition in providing the data to the AER.
(b) PWC must report the sum of non-coincident maximum demand at the zone substation level divided by summation of zone substation thermal capacity.	We have applied this method, as noted in Methodology and Assumptions section.
(c) For the purpose of this measure, thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity factors included if relevant). This must be the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity should similarly be the continuous rating.	Our data includes continuous load capacity of the zone substation using the lowest of the transformer capacity.

Template - 3.7 Operating Environment Factors

Table 3.7.1 - Density factors

Source of Data

The density factors were calculated using other RIN data as shown in the formula set out in the methodology section. The source of this information is explained elsewhere in the Basis of Preparation.

Estimated or actual information

The source data from the RIN is all considered 'estimated information', therefore this data must also be estimated information. Please look at the Basis of Preparation for templates 3.4 and 3.5 for a fuller description of the underlying methodology for each variable.

Methodology and assumptions

The density factors were calculated as follows:

$$CustomerDensity = (DOPCN0201 + DOPCN0202 + DOPCN0203 + DOPCN0204 + DOPCN0205 + DOPCN0206) / DOEF0301$$

$$EnergyDensity = (DOPED01 \times 1000) \div (DOPCN0101 + DOPCN0102 + DOPCN0103 + DOPCN0104 + DOPCN0105 + DOPCN0106)$$

$$DemandDensity = (DOPSD0201 \times 1000) \div (DOPCN0101 + DOPCN0102 + DOPCN0103 + DOPCN0104 + DOPCN0105 + DOPCN0106)$$

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

The RIN did not contain any specific instructions for the calculation of density factors.

Table 3.7.2 - Terrain factors

Source of Data

We have used the output from the GIS script and data.

Estimated or actual information

Standard vehicle access is not calculated in business systems or historically reported. We ued route length in 2017-18 and assumptions about what parts of the network require 4WD access for a significant portion the year. Different assumptions would materially affect the calculation of this variable and is therefore estimated information.

Methodology and assumptions

The calculation is based on a script in the GIS system. Networks located within town boundaries including Darwin, Palmerston, Katherine, Alice Springs and Tennant Creek, as well as smaller towns such as Adelaide River and Batchelor are considered to have Standard Vehicle Access. Where network overhead lines are located greater than 15 metres from gazetted roadways and outside of the town boundaries were identified using the geographic Information System (GIS) network data and the length of the identified circuits calculated. Analysis was performed using SQL database scripting tool Safe Software FME.

Maintenance Span counts are calculated in 2.7 Vegetation Management. These figures are based on inspection data collected by our vegetation contractor, Active Trees, and enriched with region and feeder information from GIS using FME. Total Number of Spans is a complete count of all Spans in the GIS, this includes all regions and both regulated and non-regulated areas of the network.

Our three isolated networks are characterised by terrain that is difficult to access when outside of urban areas. The Darwin-Katherine network experiences substantial wet season rain between October and May which makes any travel off-road very difficult and often impossible with 2WD vehicles until June, and sometimes later depending on the timing of the wet season.

The southern networks of Tennant Creek and Alice Springs are dryer, however off-road access is generally also restricted to 4WD only due to the soil being very soft and sandy and the large washouts which are created when rain does occur. The southern regions are also heavily grassed which makes it difficult to identify washouts, and vehicle damage and hang-ups are common based on anecdotal evidence from field staff. No permanent access tracks are maintained by us due to the costs associated with reinstatement after each wet season in the northern region and regular rainfall damage in the southern region.

Based on the above characteristics, and no actual information being available, we have assumed that a 4WD vehicle is required to access a circuit greater than 15 metres from a standard roadway in areas outside of Administrative Town Boundaries defined by the Northern Territory Department of Lands and Planning.

Confidential Information

No confidential information has been provided in this template.

Consistency with RIN requirements

Appendix E of the RIN	Consistency with requirement
9.1(a) Complete table 3.7.2 in accordance with the definitions provided in Appendix F	We have applied the definition in Appendix F to complete table 3.7.2.
(b) IF PWC has actual information, PWC must report all years of available data. If PWC does not have actual information on these variables, then it must estimate data for the most recent regulatory year -	We do not have actual data, so have only reported for the relevant regulatory year (ie: 2017-18).

Table 3.7.3 - Service area factors

Source of Data

We used output from the GIS script and data used to scale from previous years. The source for each variable is as follows:

- Total Route Length and Standard Vehicle Access Data Sheet - 2017-18 Determining Standard Vehicle Access for table 3.7.2 and 3.7.3 EB RIN
- Vegetation Zone Route Length and Total Number of Spans - 2017-18 Vegetation Management for Economic Benchmarking RIN Template 3.7.1 and 3.7.2, and Category Analysis RIN Template 2.7.1 and Span Data for Table 3.7.2 and 3.7.3 in the Economic Benchmarking RIN.
- Asset Age Profile - Asset Data and Charts for Asset Management Plans Route length from SQL scripts for overhead Route Lengths With Feeder

Estimated or actual information

The data has been calculated using business systems and is considered actual information under the RIN definition.

Methodology and assumptions

Our method to calculate route line length was as follows:

- the length of service lines not to be counted;
- the length of a span that shares multiple voltage levels is only to be counted once; and
- the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

To calculate route line length for the 2017-18 year, an SQL data base script has been developed using SQL database scripting tool Safe Software FME to perform the following analysis of GIS data. We first of all calculated the length of service lines up to 2 metres within any property boundary. We then calculated the length of the network as per the length of a span that shares multiple voltage levels is only to be counted once and the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

The route length SQL script output was an excel spreadsheet with a route length and service line lengths for each feeder. This data was then used to calculate the route line length for each vegetation management zone in CA RIN Template 2.7 and then added together to calculate the total route length of the regulated network for 2017-18 only.

Confidential Information

There is no confidential information in this table.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
9.2 PWC must input the route line length of lines for PWC's network. This is based on the distance between line segments and does not include vertical components such as line sag. The route line length does not necessarily equate to the circuit length as the circuit length may include multiple circuits -	We have inputted route line lengths based on distance between line lengths.

Appendix A: Capex model

Power and Water has prepared a Capex model to provide data in the Category Analysis templates. In principle, this model uses project data from Power and Water's financial and asset management systems to assign capital expenditure and asset volumes to the AER's expenditure categories and service classifications. Where possible, existing Power and Water system data is mapped directly into RIN categories, however in many cases manual intervention was required to achieve the necessary disaggregation.

There are three primary data sources for the CAPEX model:

- Project expenditure data was extracted from Maximo. This dataset is a list of Power Networks' projects with expenditure by financial year, expenditure type and program
- Asset financial data, such as the installation date, quantity and cost of each asset capitalised on a project, was obtained from FMS.
- Asset technical data, such as asset class, capacity, voltage, feeder ID and location was extracted from Maximo.

The three datasets were combined to form a list of assets capitalised against each project that had expenditure during the regulatory year. The relevant project and asset technical and financial details were also included. This data set formed the basis for the detailed RIN categorisation and is found in the "Analysis" sheet in the CAPEX model.

Manual Adjustments to Capex model

In many cases, the source data had to be manually adjusted to ensure that expenditure was properly attributed to the RIN expenditure categories, correct data errors or fill in missing information. All manual adjustments have been documented in the capex model. The primary drivers of these manual adjustments are discussed below.

Repairs & Maintenance CAPEX

In many cases, expenditure that had been recorded in Maximo as Repairs and Maintenance (R&M) expenditure is considered to be augex or repex in the RIN. To address this, the instances of augex and repex being captured as R&M have been identified and classified as augex or repex for the purposes of this submission and thus included in the capex model.

Erroneous system data

There were several instances where capitalisation records appeared to be erroneous and were adjusted. For example, in some cases the costs of an entire project were capitalised on a single asset, when multiple assets had been installed.

There were also instances of dates and quantities being obviously incorrect. Where these were discovered they were corrected in the model.

Projects in progress

Many projects were in progress at the completion of the RY, or they had been completed but not yet capitalised. These projects were treated as follows:

- If they were complete at the end of the regulatory year, the relevant assets were added to the model manually and costs and quantities allocated accordingly.
- If they were incomplete at the end of the regulatory year but had significant expenditure, the assets were added manually and costs were attributed accordingly (the quantities remained zero)
- If they were incomplete at the end of the regulatory year and had insignificant expenditure, the entire project expenditure was allocated to the most appropriate category (the quantities remained zero).
- If they were incomplete at the end of the regulatory year, but we knew the assets are commissioned, the project expenditure was allocated to the most appropriate category and the quantities were manually allocated.

Non-network and Capitalised Network Overheads Allocations

Non-network expenditure, such as the purchase of tools and equipment is by default allocated to standard control services. However, the non-network assets themselves may be used across all services and in the non-regulated network. Therefore, a portion of non-network expenditure has been allocated to alternative control services and non-regulated service classes, in proportion to the direct Capex expenditure against each service class.

The same is true for the Capitalised Network Overheads expenditure, and this has been treated the same way.

High-Level Categorisation

The Power and Water technical and financial details were used to categorise each asset into the high-level RIN categories:

- Service Class
- Expenditure Category
- RAB Category
- UC Category

The categorisation used a series of mapping tables to automatically assign the values where possible. For example, the AER Service Classification was mapped using the Power and Water categories “Entity”, “Program” and “Asset Class” as seen in the table below.

AER Service Class	Work Type	Entity	Program
METERING			NME
QUOTED SERVICE		21	NRW
SCS		21	
NON-REGULATED		22	

Similarly, the AER expenditure type was mapping using the Power and Water categories "Work Type", "Work Category" and "Program" as outlined below.

AER Expenditure Category	Work Type	Project ID	Program
Balancing Item		PRD33086	
Replacement	RENEWALREPLACEMENT		Not NCC, NCA, NLS
Augmentation	EXTENSIONS, SERVICEIMPROVEMENT		Not NCC, NCA, NLS
Connection			NCC, NCA
Network Overheads			NLS
Non-network	NONSYSTEMASSETS		

The full set of mapping tables is defined in the "Mapping" worksheet. If a direct mapping was not available, or it resulted in an incorrect outcome, the values were chosen manually. These manual corrections are recorded in the capex model.

There were other high-level categorisations undertaken in the model that were not directly related to RIN requirements. The most critical of these is the Power and Water Asset Class, which aligns with the Asset Management Plans and is frequently used to assist in the detailed categorisation.

Detailed Categorisation

Once the high-level categories were assigned, further categorisation was performed in order to achieve the disaggregation required by each RIN table. For example, all assets categorised as Expenditure Category "Replacement" were required to be further categorised into one of the REPEX categories in RIN 2.2.Separate sections in the model are defined for Augmentation, Replacement, Connections and Non-Network projects, and these are discussed further in the relevant sections of this document for each.

Asset Costs

The asset capitalised cost was typically used directly as the final asset cost. However, there were instances where this was not possible. In particular, if a project had been partially capitalised the project expenditure would not reconcile to the sum of the asset costs capitalised under that project. In these instances, the asset costs were adjusted manually.

The RIN CAPEX tables typically require that expenditure be reported "as-incurred" by financial year. The CAPEX model input data has the project cost "as-incurred" by financial year, but the asset cost as a lump sum. To achieve an "as-incurred" asset cost, the project expenditure in the RY is allocated to the assets in proportion to the asset costs.

$$RY\ Asset\ Cost\ = RY\ Project\ Expenditure * \frac{Asset\ Capital\ Cost}{\sum Project\ ITD}$$

The project labour, materials and contract costs are allocated to the asset in a similar way.

Asset Quantities

The asset capitalised quantity was used directly as the final asset quantity, with the exception of any errors which were corrected as discussed in the Manual Adjustments to CAPEX Model section above.

The RIN CAPEX tables require that asset quantities be reported in the year of installation. Where possible, the installation date from the capitalisation data was used, however in some cases, particularly where the asset was upgraded (i.e. retains its original installation date) or the project had yet to be capitalised, this date was not able to be used. Therefore the asset installation year was assumed to be within the regulatory year if:

- The installation date fell within the regulatory year ; or
- The project was placed On Hold within the regulatory year ; or
- The last project work order was complete within the regulatory year.
- The asset quantities were also checked against the same project in the previous submission to ensure quantities were not being double counted.

Key documents include

AER Expenditure Category	Work Type
CAPEX Model	Capex Model 2017-18
TM1 Data extract	TM1 Asset Cost Extract - PN Allocation View_201881495756
FMS Data extract	20180814_oaprd2_PN_capitalised_assets
Maximo Asset Data Extract	SRQ016667 - Maximo - Data Extract - PN - PROJ

Maximo Project Expenditure Extract	SRQ016667 - Maximo - Data Extract - PN - PROJ_EXP
Previous Submission Capex Backcasting Model	CAPEX Backcasting Model - 16 March Submission

Appendix B: Repairs & maintenance model

The RIN requires historic repairs and maintenance expenditure information to be provided in the Category Analysis template. We have prepared an R&M backcasting model to provide the historic R&M information in the templates.

The R&M model takes input data from Power and Water's asset management system, and converts this into the volume and expenditure data as required by the various RIN tables. The AER Expenditure Categories relating to R&M are "Routine Maintenance", "Non-routine Maintenance", "Emergency Management" and "Vegetation Management". Where possible, existing Power and Water system data is mapped directly into RIN categories using defined mapping tables, however in many cases manual intervention was required to achieve the necessary disaggregation.

Maximo work order expenditure and asset technical data was used as the base for the model. The resulting dataset was a list of all Maximo work orders that had expenditure in the Regulatory Year, with relevant work order and asset details to assist with categorisation. This data set formed the basis for the detailed RIN categorisation and is found in the "Analysis" sheet in the R&M model.

Manual Adjustments to R&M model

In many cases, the source data had to be manually adjusted to ensure that expenditure was properly attributed to the RIN expenditure categories, correct data errors or fill in missing information. All manual adjustments have been documented in the R&M model. The primary drivers of these manual adjustments are discussed below.

R&M to CAPEX

In many cases, project expenditure that had been recorded in Maximo as Repairs & Maintenance is considered to be Augex or Repex in the RIN. To address this, the instances of Augex and Repex being captured as R&M have been identified and excluded from the R&M model.

R&M to ACS Fee Based

Due to an issue with the way the service request system in Maximo is configured to create work orders, the costs of ACS activities like disconnections and reconnections have been recorded as R&M expenditure in some cases. There are also work orders which have been correctly raised as R&M but were actually ACS Metering expenditure. These scenarios have been manually corrected in the model.

Other corrections

There were several other corrections to individual fields made in order to cleanse the data. All corrections are visible in the "Manual Categorisation" section of the model.

High-Level Categorisation

The Power and Water technical and financial details were used to categorise each work order into the high-level RIN categories:

- Expenditure Type
- Service Classification
- Expenditure Category

This was accomplished using mappings to automatically assign the values where possible. For example, the AER Expenditure Type was mapped directly to the Power and Water category "Resource Type".

AER Expenditure Type	Resource Type
Labour	INTERNAL LABOUR
Materials	MATERIALS PURCHASE, STORE STOCK
Contractor	SERVICES RESOURCE

The AER Service Classification was mapping using the Power and Water categories "Work Category", "Service" and "Entity".

AER Service Classification	Work Category	Service	Entity
SCS	REPAIRSMAINTENANCE	Not (ELECMTR, STRTLGHT)	21
METERING	REPAIRSMAINTENANCE	ELECMTR	21
STREETLIGHTS	REPAIRSMAINTENANCE	STRTLGHT	21
NON-REGULATED			22

Similarly, the AER Expenditure Type was mapping using the Power and Water categories "Work Type" and "Work Category" as outlined below.

AER Expenditure Category	Work Category	Work Type
Routine Maintenance	REPAIRSMAINTENANCE	PREVENTATIVEMAINT
Non-Routine Maintenance	REPAIRSMAINTENANCE	PLANNEDMAINTENANCE
Emergency Response	REPAIRSMAINTENANCE	UNPLANNEDMAINTENANCE

If a direct mapping was not available, or it resulted in an incorrect outcome, the values were chosen manually. These manual corrections are recorded in the R&M model.

There were other high-level categorisations undertaken in the model that were not directly related to RIN requirements. The most critical of these is the Asset Class, which aligns with the Asset Management Plans and is frequently used to assist in the detailed categorisation.

Detailed Categorisation

Once the high-level categories were assigned, further categorisation was performed in order to achieve the disaggregation required by each RIN table. For example, all work orders categorised as Expenditure Category "Routine Maintenance" or "Non-routine Maintenance" were required to be further categorised into one of the maintenance categories in Template 2.8. This is discussed further in the relevant sections of this document for each table.

Reconciliation

The total R&M expenditure for each financial year in the period of interest was reconciled against the trial balance. There are some outstanding differences, but these are considered immaterial and included in the balancing item in table 2.1.2.

RIN Requirements

Specific RIN and BOP requirements are discussed in the relevant section for each RIN Template.

Source documents for the model are identified below.

Information	Source
R&M Model	R&M Model 2017-18
Maximo Work Order and Asset Data Extract	SRQ016002 - Data Extract - Power Networks - List of RM Work Orders for 1718 RINs
Maximo Vegetation Contract Transactions Extract	Vegetation Management data Extract for CA RIN
Maximo Emergency Response MED Expenditure	17/18 MED Expenditure for RIN 2.9
Previous Submission R&M Backcasting Model	R&M Backcasting Model - TM1 Data for R&M Backcasting 2012/13 to 2016/17

Appendix C - Opex Methodology

The operating expenditure reported in the RIN templates has been based on the financial accounts that were used to produce the annual Audited Statutory Accounts. Power and Water Corporation calculated the RIN opex categories in two different streams:

- Total operating expenditure was sourced from Power Network's Trial Balance.
- Repairs and maintenance work orders were also used because the Trial Balance did not contain adequate information to categorise expenditure into the RIN categories.

The repair and maintenance work order expenditure was reconciled to the Trial Balance and then the disaggregated financial data was sourced from work orders. Appendix B outlines how the repairs and maintenance expenditure was allocated to the RIN Expenditure Categories. After the repairs and maintenance expenditure was identified in the Trial Balance, the remaining expenditure in the Trial Balance was allocated to the AER categories based on the nature of each account.

Where an account in the Trial Balance was linked to a work order that was directly allocated to a RIN Service Classification and RIN Expenditure Category, we allocated it directly to the Service Classification and identified it to be 'core activity' for the Expenditure Category. This ensured the total expenditure for each Service Classification reconciled to the Audited Statutory Accounts. For standard control services the 'core activity' expenditure is equal to the sum of vegetation management, emergency response, maintenance and the balancing item expenditure. This ensures there is no double counting of costs.

The remainder of this Appendix explains how we allocated the total operating expenditure and the disaggregated repairs and maintenance expenditure into the RIN tables.

Account exclusions

The Trial Balance contains all expenditure for Power and Water for each year and is the basis for the Audited Statutory Accounts, which made it possible to determine the total expenditure on distribution services to be reported in the RIN. However, not all expense accounts relate to operating expenditure for distribution services, therefore a number of initial adjustments were made:

- All accounts that did not relate to 'Power Networks' were removed. This included removing the accounts for Water Services and the Corporate accounts. Corporate expenditure is accounted for within the Power Networks accounts as the Power Networks accounts include an allocation of Corporate expenditure.
- Assets, Liabilities and Equity related accounts were removed as they do not relate to operating expenditure. We also excluded expense accounts that did not relate to expenditure, such as bad debts and asset revaluation expenses.

Labour cost adjustments

Our accounts include labour costs in a set of accounts that for salaries and remunerations expenses. Our labour costs are also booked to repairs and maintenance and capital projects accounts. Labour recovery accounts are used to ensure our labour costs are only accounted for once.

We used the labour accounts for salaries and remuneration and the repairs and maintenance accounts to report the labour costs in the RIN. To ensure labour costs were not double counted in the RIN, we proportionately reduced the salaries and remuneration accounts by the total amount of labour booked to repairs and maintenance and capital projects.

Account classifications

We classified all accounts with each one of the six classifications as set out below

1.Service classification	2.Expenditure types	3. Cost Type	4. Expense or capital	5. Allocation type	6. P&L category	
SCS	Core Activity	Labour	Opex	Direct	Finance revenue	Impairment of non-current assets and onerous contract provisions
ACS - Metering	Non-network: IT	Materials	Capex	Indirect	Inter-group sales	Other expenses
ACS - FB	Non-network: Fleet	Contract	Corporate Costs	Exclude	Other income	Repairs and maintenance expense
ACS - QS	Non-network: Buildings and Property	Other	Exclude		Revenue from rendering of services and government grants	Net loss on disposal of property, plant and equipment, inc gifted streelights
Unregulated	Network OH	Corporate Costs			Revenue from sale of goods	Depreciation and amortisation expenses
Unallocated	Corporate OH				Employee benefits expense	

Cost allocation

The unallocated accounts were allocated to the service classifications using the proportion of the expenditure directly attributed to each service to the total expenditure directly attributed to all services.

Labour costs

The costs allocated to Power Networks from the corporate entity do not currently distinguish a cost type so the individual accounts could not be assigned to a cost type category. So Corporate cost types were allocated based on analysis of the proportion of labour costs incurred in the corporate entity.

Capitalisation of indirect costs and unallocated costs

Before 2016-17, our Statutory Capitalisation Policy capitalised labour, invoiced contract and service costs where they directly related to capital projects but did not include indirect support costs.

In 2016-17, we extended our application of the Statutory Capitalisation Policy to include the capitalisation of an allocation of indirect support costs where they were deemed to be integral to the acquisition or construction of capital assets, provided they complied with AASB 116 Property, Plant and Equipment.

We developed an accounting treatment and methodology for the capitalisation of these indirect support costs from 2016-17, in accordance with AASB 116. The extension of our existing methodology was not considered to be a change in accounting policy by either our Board or our external auditor. As a result, there were no prior year adjustments made.

We capitalise the same corporate and network overhead accounts for regulatory purposes, but do so in proportion to the ratio of direct capex to total direct expenditure. If the ratio changes, the fraction of unallocated costs capitalised also changes. This is provided for in our CAM.

Calculating total expenditures

The total expenditure provided in the RIN tables is the sum of the adjusted account balances after capitalisation and overhead allocation using the relevant classifications described above.