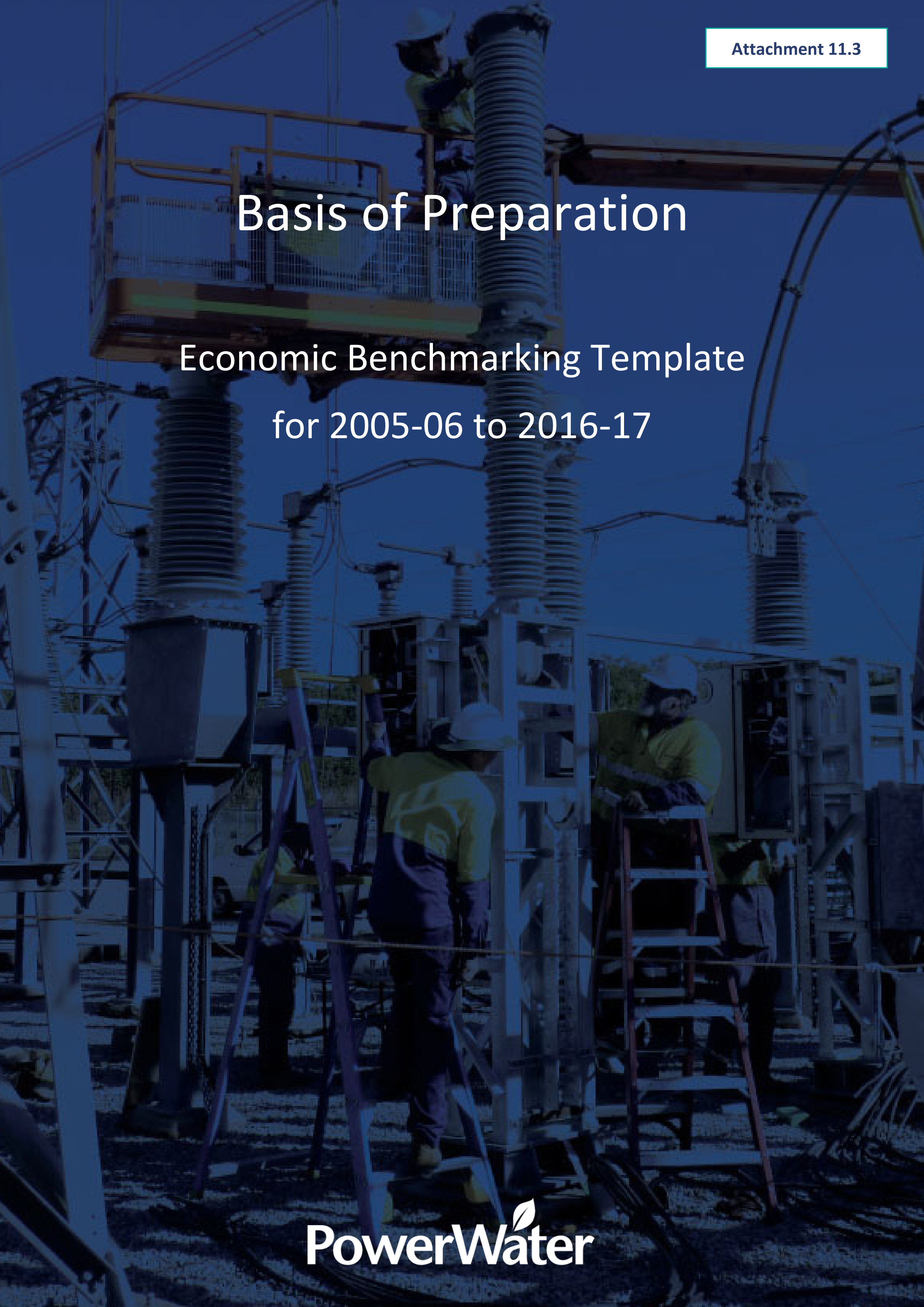


Attachment 11.3

Basis of Preparation

Economic Benchmarking Template

for 2005-06 to 2016-17

PowerWater

PowerWater

Contents

Glossary

Term	Meaning
ACS	Alternative Control Services
AMS	Asset Management System
BOM	Bureau of Meteorology
BOXI	Box of Information (BOXI) – HR database
FMS	Financial Management System
GIS	Geographic Information System
Maximo	Asset Management System software
MV90	Metering System
NMI	National Metering Identifier
PILC	Paper insulated lead covered
Power Networks (PN)	The operating unit or entity within Power and Water Corporation that provides electricity services.
RMS	Retail Management System, which is sometimes referred to as the billing system
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SQL	Structured Query Language
SWER	Single wire earth return
XLPE	Cross-linked polyethylene insulation

Overview

On 9 November 2017, the Australian Energy Regulator (AER) issued Power Water Corporation (Power and Water) with a Regulatory Information Notice (RIN) under Division 4 of Part 3 of the National Electricity (Northern Territory) Law. Clause 1.3 of Schedule 1 of the RIN requires:

> *1.3 For all information, other than forecast information, provide in accordance with this notice and the instructions in Appendix E, a basis of preparation demonstrating how we have complied with this notice in respect of:*
>
> *(a) the information in each regulatory template in the Microsoft Excel Workbooks attached at Appendix A; and*
>
> *(b) any other information prepared in accordance with the requirements of this notice.*

This Basis of Preparation relates to the information provided in the regulatory template "Workbook 2 – Economic Benchmarking".

Structure

This document was written using the same structure in the regulatory template. Each chapter of this document corresponds to a particular template and then sections within each chapter are used to explain the tables within each template.

For all information in the template we have explained:

1. How we have complied with the RIN requirements;
2. The Methodology and assumptions we used to calculate the information;
3. Whether the information is estimated or actual (based on the RIN definitions);
4. The source of the information; and
5. Whether the information contains confidential information.

Limitations of our data

We expect that the AER will publish the final form of the basis of preparation and the associated data template with our information. Further, we expect that the AER and third parties will use this information for different purposes. We recommend that anyone using this information should do so at their own risk. We do not provide any warranty that this information is fit for the purpose of other parties.

We do, however, acknowledge that the information provided 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.

Best estimates

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:

1. we were only able to develop a single method for the majority of estimated information; and

2. the estimated information was prepared and reviewed by appropriate subject matter experts.

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

1. Template 3.1 – Revenue

1.1 Templates 3.1.1 and 3.1.2 - Revenue by chargeable quantity and customer

1.1.1 Consistency with the RIN requirements

Appendix E Instructions	Consistency with Requirements
Clause 3.3: PWC must report revenues split in accordance with the categories in Workbook 2 – Economic benchmarking. Workbook 2 – Economic benchmarking requires PWC to report revenues by chargeable quantity (table 3.1.1) and by type of customer type/class (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 2005/06 to 2016/17 and the annual totals are equal as required.
Clause 3.4: PWC must report revenues split into standard control services and alternative control services in accordance with the service classifications in the AER's framework and approach paper.	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 3.5: 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 3.6: 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 historic regulatory and financial accounts.
Clause 3.7(a): Revenues reported [in template 3.1.1] 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).	We allocated revenue to the most appropriate category based on the type of charge and tariff.
Clause 3.7(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).	Revenues that could not be classified to specific chargeable quantities in variables DREV0101 to DREV0112 were added to the variable DREV0113.
Clause 3.7(c): 'Revenue from unmetered supplies' is the same for table 3.1.1 as for table 3.1.2, so they must be equal.	Data for revenue from unmetered supplies in table 3.1.1 equals that in table 3.1.2.
Clause 3.8(a): PWC must allocate revenues [in template 3.1.2] to the customer type that most closely reflects the customers from which PWC	We allocated revenue to the most appropriate category based on the type of charge and tariff, which in turn relates to specific customer types.

Appendix E Instructions	Consistency with Requirements
received its revenue.	
Clause 3.8(b): Revenues that PWC cannot allocate to the customer types DREV0201–DREV0205 must be reported against 'Revenue from other customers' (DREV0206).	Amounts of revenue that could not be allocated to customer types DREV0201 to DREV0205, were reported in DREV0206.

1.1.2 Methodology and assumptions

We completed tables 3.1.1 and 3.1.2 using the following method:

- All Power Networks' revenue accounts for standard control services and alternative control services (ACS) were extracted from the annual Trial Balance accounts that were used to produce the Audited Statutory Accounts for each of the reporting years. The following table shows the general ledger codes used to identify the revenue accounts for SCS and ACS in Power Networks – Regulated Trial Balance.

Revenue	2005-06 to 2013-14	2014-15 to 2016-17
Standard Control Services		
Standard Control Services Revenue Jacana Energy	-	39-434
Standard Control Services Revenue Other Retailer	-	39-435
Standard Control Services Revenue - PN Unbilled	-	39-436
Miscellaneous Income	39-422	-
Transfer Pricing Revenue – PN	46-221	48-484
Transfer Pricing Revenue – PN Unbilled	46-224	48-931
Alternative Control Services		
Alternate Control Services	33-055	39-423
Revenue on Cost of Sale > $5000	37-011	37-431
Revenue on Cost of Sale < $5000	37-013	37-433

- Supporting financial data for each revenue account was collected to help allocate the revenue into the categories required by the templates. The supporting information included transaction lists, billing system reports and statement of charges. The supporting information was retrieved from our Financial Management System (FMS), Retail Management System (RMS), Network Metering System (MV90) and other sources as noted in 1.1.5.
- Using the supporting information, the revenue accounts were allocated to the most appropriate template revenue categories and the most appropriate service classifications. The total revenue for each category and service was reported in the template.

In years that we did not separately charge for metering services, we allocated 3% of network tariff revenue to ACS metering. This was based on the average of the two ratios in 2019/20:

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

Prior to 2013-14, we levied our public lighting charges as part of our retail business and did not raise an associated 'network' charge. Therefore, for the reporting years prior to 2013-14 the public lighting related revenue reported was calculated using the public lighting tariffs multiplied by the quantity of public lighting services. These amounts were not included in the Power Networks -Regulated Trial Balance.

1.1.3 Estimated and actual information

The information reported in templates 3.1.1 and 3.1.2 is materially dependant on financial system information and statement of charges to third party retailers. We did not apply any assumptions that would vary the data materially. Therefore, all information in templates 3.1.1 and 3.1.2 is defined by the RIN as actual information, noting the calculation of public lighting charges described above.

1.1.4 Confidential Information

Templates 3.1.1 and 3.1.2 do not contain confidential information.

1.1.5 Source of the Information

Information	Source
Actual billing data was sourced for all years from the RMS billing system.	Retail Management System (RMS)
Actual invoice and statement of charges for third party retailers	kWh consumption based on Meter Data from Power Network Metering System MV90
Manual journals posted for accruals and manual adjustments	Financial Management System (FMS)
Public lighting prices and volumes	Prices were sourced from the Utilities Commission determinations and Ministerial Direction. Volumes were soured from GIS.

1.2 Template 3.1.3 - Revenue (Penalties) Allowed (Deducted) Through Incentive Schemes

Template 3.1.3 requires us to report the revenue and penalties we have recovered under incentive schemes for 2005-06 to 2016-17. We have not been subject to incentive schemes in the past and therefore have reported '0' for all cells in this template.

2. Template 3.2 – Operating expenditure

2.1 General methodology

Our ‘Power Networks’ operating unit provides all the direct and some indirect distribution services provided within Power and Water Corporation. Other operating units that provide distribution services indirectly 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 Networks’ accounts, which includes its portion of the costs allocated from Finance/Corporate, Retail and System Control costs.

The Trial Balance for Power Networks is the source of the operating expenditure reported in the RIN for distribution services. The Power Networks’ 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 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:

1. Distribution Services, which are split into:
    a) Standard Control Distribution Services
    b) Alterative Control Services – Metering (Types 1 to 6)
    c) Alterative Control Services – Fee Based Services
    d) Alterative Control Services – Quoted Services
2. 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 approved Cost Allocation Method (CAM). In summary, the CAM requires:

1. 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 particular distribution service. All other accounts were deemed to be unallocated.

2. All unallocated costs were attributed to the distribution services based on the proportion of the amounts directly allocated as described in the previous step.

A number of specific adjustments were undertaken to ensure an appropriate estimate for each variable could be provided as described below.

2.1.1.1 Labour recovery adjustments

We book the time of employees against projects and programs of work in our asset management system, Maximo, in order 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.

2.1.1.2 2016-17 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 costs. If the ratio changes, the fraction of unallocated costs capitalised also changes. This is provided for in our CAM.

For comparison we capitalised $8.6m of overhead costs in 2016-17 in our Audited Statutory Accounts. In applying the approved CAM, we have calculated that a $11.4m of capitalised overhead expenditure.

2.2 Templates 3.2.1 and 3.2.2 - Opex Categories and Opex Consistency

2.2.1 Consistency with the RIN

Appendix E Requirements	Consistency with the Requirements
Clause 3.9: For all tables, opex must be split into standard control services and alternative control services in accordance with the AER's framework and approach paper.	We have applied the service classifications as defined by the AER in its Framework and Approach paper. That is opex was attributed and allocated to SCS and ACS using the methodology defined in our CAM.
Clause 3.10: In addition, opex must be split into the variables as defined in Appendix F for Workbook 2 – Economic benchmarking, regulatory template 3.2, table 3.2.2.	We have split opex into the defined categories as per Appendix F.
Clause 3.11: 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 3.12: 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 3.13: Workbook 2 – Economic benchmarking, 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 3.14: Opex must be prepared for all regulatory years in accordance with PWC's cost allocation method and the service classifications contained in the AER's framework and approach paper. Workbook 2 – Economic benchmarking, regulatory template 3.2, table 3.2.2 Opex consistency – current cost allocation approach:	We have applied the approved CAM to all years and for the service classifications in the AER's Framework and Approach. In earlier years of the reporting period, we have not captured the costs of the ACS services and are unable to make an estimate of the cost of these services for all years. Indeed it is not possible to capture whether any significant volume of activity occurred in relation to these services.
Clause 3.14(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	Network Services opex has been reported as equal to SCS opex as it is assumed to not include metering, connections or public lighting.

Appendix E Requirements	Consistency with the Requirements
their impact on productivity can be assessed and they can be incorporated or excluded from the services being benchmarked if necessary.	
Clause 3.14(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 3.14(c): Opex must be prepared in accordance with PWC's cost allocation method and the service classifications contained in the AER's framework and approach paper.	We have applied the approved CAM to all years and for the service classifications in the AER's Framework and Approach. In earlier years of the reporting period, we have not captured the costs of the ACS services and are unable to make an estimate of the cost of these services for all years. It is not possible to capture whether any significant volume of activity occurred in relation to these services.

2.2.2 Methodology and assumptions

Opex for Network Services

Opex for network services has been calculated as the total expenses attributed to SCS. The SCS direct eliminating the following costs from Power Networks expenses identified costs:

1. ACS metering costs were identified by work orders and business unit costs;
2. ACS fee and quoted services were identified by work orders and business unit costs;
3. unregulated activities (street lighting and remote communities related services) were identified by work orders, business unit and entity; and
4. 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. The basis of this information is the following:

- costs identified as business unit 223 metering, except allocated overhead costs;
- costs identified as metering in asset management work orders; and
- 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 is therefore the opex for connections services is reported as zero. Within ACS, the AER has described the following Fee Based Services as Connection Services:

- energisation;
- de-energisation; and
- re-energisation.

Therefore, the opex reported for these activities for this variable has been sourced from Template 4.3 in the Category Analysis workbook. The Category Analysis RIN only requires these amounts to be reported for 2013-14 to 2016-17. Prior to these years we do not have a detailed basis to estimate the expenditure associated with this subset of ACS Fee Based services. Therefore, for completeness, we have assumed the expenditure for 2005-06 to 2012-13 was the same as that incurred in 2013-14.

Opex for Public Lighting (DOPEX0204)

The AER has not classified public lighting as SCS or ACS because our street lighting service is currently being handed over to local councils who will provide these services moving forward. We have entered zero for public lighting variables.

Opex for Amounts Payable for Easement Levy or Similar Direct Charges on DNSP (DOPEX0205)

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 (DOPEX0206)

We identified known 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.

2.2.3 Estimated and actual information

The information is an estimate based on RIN definitions, this is mainly due to the labour adjustment made to individual business units discussed in General Methodology above. Alternative assumptions could have been made that result in different opex costs for categories.

2.2.4 Source of the information

Information	Source
Operating expenditure for distribution services	Trial balance

Information	Source
Labour cost adjustment	Maximo (Asset Management System)
Connections expenditure in ACS	Category Analysis RIN Template 4.3

2.2.5 Confidential information

The template does not contain confidential information.

2.3 Template 3.2.3 Provisions

2.3.1 Consistency with the RIN

Appendix E Requirements	Consistency with the Requirements
Clause 3.16(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 contained in the AER's framework and approach paper.	Our CAM, as approved by the AER, 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. See the methodology below.
Clause 3.16(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.	Provisions were not reported in our historic regulatory accounts so this requirement is not possible to achieve.
Clause 3.16(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 and Payroll Tax. We do not have any other provision accounts associated with Distribution Services.
Clause 3.16(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.	We have used the variable codes DOPEX030A to DOPEX030D. This allows for 4 provision accounts in total.

2.3.2 Methodology and assumptions

We have undertaken the following to complete template 3.2.3 for provisions 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, known as Power Networks – Regulated. Utilising this extract was the simplest way to extract the smallest subset of our statutory accounts that contain all of the provision data for 'distribution services'.
- Established the opening and closing balances of each account for Power Networks – Regulated. 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.
- Establish the amounts added during the year for Power Networks – Regulated.
- Ensure 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 following table shows the general ledger codes used to identify the opening and closing balance amounts from the trial balance.

Provision	Account	2005/06 to 2013/14	2014/15 to 2016/17
Long Service Leave	Current Long Service Leave Provision	62-021	67-014
	Long Service Leave Payment in Lieu	65-022	67-688
	Non-Current Long Service Leave Provision	82-011	82-806
Recreation Leave	Current Recreation Leave Provision	65-011	67-013
	Rec Leave Payment in Lieu	65-012	67-686
	Rec Leave Cash Up	65-013	67-687
	Rec Leave Loading	65-031	67-015
	Leave Fares	65-041	67-685

The amounts used for long service leave and recreation leave provisions were calculated using the payroll report (PIPS) for each 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 monthly manual adjustments posted to add the provision on-costs (ie superannuation and payroll tax).

Provision for Fringe Benefits Tax

The closing balance for provision for FBT is recorded in the trial balance report for each year against the below account codes. 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.

Account	2005-06 to 2013-14	2014-15 to 2016-17
Provision for Fringe Benefit Tax	66-011	67-681

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 year (April to June). 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 following account codes.

Account	2005-06 to 2013-14	2014 -15 to 2016-17
Provision for Payroll Tax	66-013	67-682

The amount used is the actual monthly NT payroll tax payments made during the year. Since lodgement and payment for payroll tax is done a month after, payroll tax for the month of June is paid the following year.

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.

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.

2.3.3 Estimated and actual information

All the data in this template is materially dependant on our Trial Balances. However, the last step in the methodology is to apportion the provisions data into the SCS classification and further into opex and capex. This allocation was undertaken using actual information from our financial accounts. Consequently, the RIN defines the information in this template to be actual information.

2.3.4 Source of the information

Information	Source
Trial Balance for 2004-05 to 2016-17	FMS
PIPS reports	Information provided by NT Department of Corporate and Information System (DCIS)
FBT Tax Provision working files	Information used in the working files is from FMS General Ledger Accounts, Personnel reports (PIPS) provided by NT DCIS, Fleet Reports and Employee FBT Declarations.
Payroll Tax Provision working files	Information used in the working files are from FMS General Ledger Accounts and Personnel reports provided by NT DCIS (including PIPS and BOXI reports)

2.3.5 Confidential Information

Template 3.2.3 does not contain confidential information.

2.4 Template 3.2.4 - Opex for High Voltage Customers

2.4.1 Consistency with the RIN

Appendix E Requirements	Consistency with the Requirements
Clause 3.15: Workbook 2 – 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.

Appendix E Requirements	Consistency with the Requirements
transformers that are owned by its high voltage customers.	
(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.

2.4.2 Methodology and assumptions

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

For the 2013-14 to 2016-17 period, distribution substation opex was calculated by summing the Maintenance Asset Categories “Distribution substation - transformers”, “Distribution substation - property” 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 for each year of the period.

The average unit cost per year for the 2013-14 to 2016-17 period was applied to 2008-09 to 2012-13 period, due to the lack of disaggregated data in template 2.8 prior to 2013-14.

The unit rate was then applied to the number of HV customers in each year to calculate the final opex for high voltage customers.

2.4.3 Estimated and actual information

Information on the opex for high voltage customers is not recorded in our systems, therefore was estimated using best endeavours as described in section 2.4.2. An alternative estimate may have resulted in a materially different outcome, and for this reason the data is estimated.

2.4.4 Confidential information

This template does not contain confidential information.

2.4.5 Source of the information

Information	Source
HV customers numbers	RMS
Data used to calculate unit rates	CA RIN Template 2.8

3. Template 3.3 – Assets (RAB)

3.1 Template 3.3.1 - Regulatory Asset Base Values

3.1.1 Consistency with the RIN

Appendix E Requirements	Consistency with the Requirements
Clause 3.17: 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 3.23: 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 3.24: 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	The AER has not made a 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 2018-19 has been reconciled to the Roll Forward Model submitted in the regulatory proposal.
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 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

Appendix E Requirements	Consistency with the Requirements
	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 3.25: 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. Straightline 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 3.31: Workbook 2 – Economic benchmarking, regulatory template 3.3, table 3.3.1 Regulatory Asset Base Values: (a) PWC must report totals for 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

3.1.2 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.

The primary limitation of the information in the 3.3 Assets (RAB) template is that it applies the 2016-17 split of depreciated replacement cost (DRC) to allocate some RAB categories to EB categories for all historical and forecast 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 estimate.
- 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 EB 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.

3.1.3 Estimated and actual information

<table>
<tr><th>Estimated and actual information</th><th>Justification 2008-09 to 2012-13</th><th>Justification 2013-14 to 2016-17</th></tr>
<tr><td>Actual additions (DRAB0105)</td><td rowspan="3">This information was sourced from the Utilities' Commission determination documentation and is therefore not based on PWC systems or records and as such it is defined by the RIN as estimated information.</td><td rowspan="2">This information is sourced from our financial accounts and there are no significant assumptions made. Therefore, this information is defined by the RIN to be actual information.</td></tr>
<tr><td>Disposals (DRAB0106)</td></tr>
<tr><td>Straight line depreciation (DRAB0103)</td><td rowspan="4">These variables are calculated in accordance with the RIN requirements and the 2013/14 external valuation report. This information is not materially dependant 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.</td></tr>
<tr><td>Opening value (DRAB0101)</td><td rowspan="3">These variables are calculated in accordance with the RIN requirements and the 2013/14 external valuation report. This information is not materially dependant 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.</td></tr>
<tr><td>Inflation addition (DRAB0102)</td></tr>
<tr><td>Closing value (DRAB0107)</td></tr>
</table>

3.1.4 Source of the information

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

3.1.5 Confidential Information

Table 3.3.1 does not contain confidential information.

3.2 Template 3.3.2 - Asset Value Roll Forward

3.2.1 Consistency with the RIN

Appendix E Requirements	Consistency with the Requirements
Clause 3.18: 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.

Appendix E Requirements	Consistency with the Requirements
Clause 3.19: 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: 3.20 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 3.21: In completing Workbook 2 – Economic benchmarking, regulatory template 3.3 PWC must report metering assets in accordance with the service classifications contained in the AER's framework and approach paper.	Type 1 to 6 metering is classified as an 'Alternative Control Service'. As explained in the methodology section below, we have reported the RAB values for these services in the ACS table only.
Clause 3.22: 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 3.23: 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 3.24: 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	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.
For years where the AER has not made a decision on values for the RAB, RAB values must be prepared in	The AER has not made a decision on our RAB in any of the reporting years, so the RAB values have been

Appendix E Requirements	Consistency with the Requirements
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.	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 3.25: 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. Straightline 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.
Standard Approach Clause 3.26: 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 3.27: 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 approach.	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 3.28: RAB allocation approach:	The RAB allocation approach has been applied to the Distribution Line and Transmission Line asset

Appendix E Requirements	Consistency with the Requirements
(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 Workbook 2 – Economic benchmarking (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	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.

Appendix E Requirements	Consistency with the Requirements
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.	
Clause 3.32: Workbook 2 – Economic benchmarking, 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

3.2.2 Methodology and assumptions

We have split our RAB values into the categories for Table 3.3.2 using the standard approach prescribed in clauses 3.26 to 3.28 of Appendix E of the RIN. We used two methods to allocate our RAB to the relevant category including:

1. Total estimated DRC for 2017
2. Total book value for the regulatory year 2017.

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

1. 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.
2. Additions are assumed to be gross capex less customer contributions.
3. 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.
4. 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:

1. Link historical and forecast RAB values for SCS and ACS based on RAB asset classes within the proposal.
2. Determine what proportion of SCS values relate to network services activities.
3. Allocate proposal RAB asset class values into EB RIN categories.
4. Calculate the RAB values by category.
5. Calculate the associated standard and remaining lives by EB RIN category.

Historical RAB Values for SCS and ACS

Within the proposal, and more specifically the supporting RIN templates, we are required to populate RAB values, split by EB categories from 2005-06 to 2023-24.

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.

Table 1: Accounts Driving Historical and Forecast RAB Movements

Account type	Methodology	Comments
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.	Linked to Table 3.3.2
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	Linked to Table 3.3.2
Straight line depreciation	All periods linked to totals in source documents and allocated to proposal RAB asset classes	Linked to Table 3.3.2 SCS depreciation was adjusted up automatically (i.e. via formula) where necessary to ensure that asset balances did not become negative when rolling back the RAB from the 2013 revaluation
Net additions	All periods linked to totals in source documents and allocated to proposal RAB asset classes	Linked to Table 3.3.2
Disposals	All periods linked to totals in source documents and allocated to proposal RAB asset classes	Linked to Table 3.3.2

Account type	Methodology	Comments
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	Not linked to Table 3.3.2
Adjustments[1,2]	Opening balance of next regulatory period less interim balance, where appropriate	Only applicable in final year of each regulatory period for periods after the revaluation Not linked to Table 3.3.2
Closing balance	Calculated as interim closing balance plus adjustments	Linked to Table 3.3.2

This structure allows us to correctly capture the types of movements required for Table 3.3.2. 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:

1. Connection services;
2. Metering;
3. Public lighting; and
4. Fee and quoted based services.

The metering RAB is classified as ACS and is therefore treated separately. We do not have a RAB relating 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:

1. Quantifying net connection related capex;
2. Quantifying net capex for asset classes which include connection capex;
3. Calculating the proportion of connection related capex;

---

[1] The structure of the EB RIN tables do not allow for adjustments to be specified. Typical adjustments made by the AER include difference between forecast and actual capex in final year, return on difference between forecast and actual and final year adjustments.

[2] Given adjustments have and will occur in the future there are justifiable reasons for a difference between closing and opening balances between regulatory periods.

4. Determining the estimated connection RAB by asset category; and
5. 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.

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 following RAB categories could be directly mapped from RAB categories to EB categories, which meant the book value method was most appropriate.

Table 4: RAB asset classes mapped directly EB RIN categories

Service Classification	RAB Category	EB 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

Service Classification	RAB Category	EB Category
ACS	Metering - Non-network IT & Communications	Other assets with short 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.

Table 5: RAB asset classes requiring the DRC method

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".

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
- 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.

Standard and Remaining Lives

This part of the process is covered in more detail below in the section describing template 3.3.5 – Asset Lives.

3.2.3 Estimated and actual information

Estimated and actual information	Justification
Actual additions (DRAB*XX*05)	This information is 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.
Disposals (DRAB*XX*06)	
Opening value (DRAB*XX*01)	These variables are calculated in accordance with the RIN requirements and the 2013-14 external valuation report. This information is not materially dependant on sourced from any of our systems or other records used in the normal course of business. Therefore, this information does not meet the RIN definition of actual information.
Inflation addition (DRAB*XX*02)	
Straight line depreciation (DRAB*XX*03)	
Closing value (DRAB*XX*07)	

3.2.4 Source of the information

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.

3.2.5 Confidential information

There is no confidential information in this template.

3.3 Template 3.3.3 - Total disaggregated RAB asset values

3.3.1 Consistency with the RIN

Appendix E Requirements	Consistency with the RIN requirements
Clause 3.22: 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 3.33: Workbook 2 – Economic benchmarking, regulatory template 3.3, table 3.3.3 Total disaggregated RAB asset values: (a) 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.

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

3.3.3 Estimated and actual information

Estimated and actual information	Justification
Value of Capital Contributions or Contributed Assets (DRAB13)	This information is materially dependant 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.
Overhead distribution assets (wires and poles) (DRAB1201)	These variables are calculated in accordance with the RIN requirements and are based on the estimated information in other templates. This information is not materially dependant 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.
Underground distribution assets (cables, ducts etc) (DRAB1202)	
Distribution substations including transformers (DRAB1203)	
Overhead assets 33kV and above (wires and towers / poles etc) (DRAB1204)	
Underground assets 33kV and above (cables, ducts etc) (DRAB1205)	
Zone substations (DRAB1206)	

Estimated and actual information	Justification
Easements (DRAB1207)	
Meters (DRAB1208)	
Other assets with long lives (DRAB1209)	
Other assets with short lives (DRAB1210)	
Value of Capital Contributions or Contributed Assets (DRAB13)	This information is materially dependant on and reconciles to our Statutory Account and is therefore defined by the RIN to be actual information.

3.4 Template 3.3.4 - Asset Lives

3.4.1 Consistency with the RIN

Appendix E Requirements	Consistency with requirements
Clause 3.34: 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: (i) On the basis of the asset's share of the RAB for the category and expected asset lives; (ii) If 1 is not available, on the basis of replacement costs and expected asset lives; (iii) If 1 and 2 cannot be applied, in accordance with the asset's contribution to the category's capacity (i.e. MVA-kms for lines and for cables and MVA for transformers).); (iv) The weighted average asset life of each category is as set out in Equation 1.	We have complied with the AER's instructions as demonstrated in our Methodology and assumptions.
Clause 3.35: Equation 1 Weighted average asset life calculation: Weighted average asset life for assets in category j = $= \sum_{i=1}^{n} \frac{x_{i,j}}{RC_j} . EL_{i,j}$	We have complied with the AER's instructions as demonstrated in our Methodology and assumptions.

Appendix E Requirements	Consistency with requirements
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 possible (and capacity shares are then a further proxy to replacement cost shares).	
Clause 3.36: 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) This 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 3.37: 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.

3.4.2 Methodology and assumptions

Service Life of New Assets

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 EB categories. The following table provides a summary of the data used to calculate the SCS lives.

Table 6: Example of SCS Standard Life Calculation by Category

DNSP	United	TasNet	AusNet	Essential	SAPN	Powercor	Jemena	Ergon	Energex	Endeavour	Citipower	Ausgrid	ActewAGL	Average
Overhead network assets less than 33kV	36	35	64	53	55	51	60	48	44	53	49	55	45	50
Underground network assets less than 33kV	36	60	50	54	55	51	46	57	60	60	49	57	45	52
Distribution substations and transformers	36	40	52	45	45	51	44	45	40	42	49	47	45	45
Overhead network assets 33kV and above	60	50	72	55	55	51	64	51	51	56	49	48	45	54
Underground network assets 33kV and above	60	60	50	54	55	51	40	45	45	45	49	46	45	50
Zone substations and transformers	60	40	46	46	45	51	34	41	50	45	49	46	40	46
Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Meters	5	-	-	26	-	-	10	15	15	25	-	-	-	16
"Other" asset items with long lives	8	34	21	27	18	15	60	36	33	46	12	28	40	29

DNSP	United	TasNet	AusNet	Essential	SAPN	Powercor	Jemena	Ergon	Energex	Endeavour	Citipower	Ausgrid	ActewAGL	Average
"Other" asset items with short lives	5	5	5	7	5	6	18	7	8	7	6	6	5	7

This approach was replicated for both network services and ACS standard lives by EB category. These standard lives are not expected to change in future submissions of table 3.3.4.

Estimated Residual Service Life

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.

3.4.3 Estimated and actual information

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

3.4.4 Source of the Information

Information	Source
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

Information	Source
	regulatory period

4. Template 3.4 – Operational data

4.1 Template 3.4.1 - Energy delivery

4.1.1 Consistency with the RIN

Appendix E Requirements	Consistency with the RIN Requirements
Clause 3.38: 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.	Energy delivered has been reported at the charging location based on amount billed.
(b) Peak, shoulder and off-peak periods relate to PWC's own charging periods.	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 3.39: 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.	Table 3.4.1.1 reports energy delivered based on the categories as defined 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.	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 3.40: 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.
(b) PWC must only report energy against 'Energy received from major generators and other DNSPs not included in the above categories' (DOPED0304) where it	We have reported Energy received from major generators and other DNSPs not included in the above categories (DOPED0304) for energy delivery that was

Appendix E Requirements	Consistency with the RIN Requirements
is not possible to allocate the energy received into on-peak, shoulder and off-peak times.	not charged for peak, shoulder or off-peak periods.
Clause 3.41: 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.
(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
(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 3.42: 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.

4.1.2 Methodology and assumptions

General methodology

For the entire reporting period, 2005-06 to 2016-17, we developed a customer number and energy consumption dataset 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:

1. The data was restricted to only include customer installations in the Darwin-Katherine, Alice Springs and Tennant Creek systems using the following District Codes:

Regulated network district codes	
AA – Alice Springs	DB3 - Batchelor
D26 – Wagait Beach	KA - Katherine
D27 – Dundee	KB1 – Pine Creek
D28 – Namarada	KB2 – Mataranka
DA – Darwin	KB3 – Larrimah
DB2 – Adelaide River	TA – Tennant Creek

2. There are 26 remote community networks that our regulated networks supply. Each of these remote communities are considered to be individual networks. Therefore, the individual customer installations supplied by the remote community networks were excluded based on the following District Codes:

District codes for remote communities supplied by regulated network		
A02 – Santa Teresa	AB9 - Tjuwanpa	K22 & K36 – Jodetluk
A03 & AB8 – Hermannsburg	D17, D31 & DB1 – Belyuen	K28 – Rockhole
A10 & AB4 – Amoonguna	D25 – Darwin Outstations	K21 & K29 – Gilwi
A11 & AB5 – Pmara Jutunta	D30 & D32 – Acacia Larakia	K30 – Muruning
A18 & AB7 – Nturiya	K03 & KB9 – Beswick	K31 – Myatt
A20 & AB0 – Wallace Rockhole	K04 & KB8 – Barunga	K19 & K32 – Wandangula
A24 – Iwupataka	K10 & K33 – Djilkminggan	T01 & TB3 – Ali Curung
AB3 – Ltyentye Purte	K14 & K34 – Binjari	TB4 – McLaren Creek
AB6 – Jay Creek	K18 & K35 – Kybrook Farm	

The dataset classified all consumption data with a customer type attribute and a tranche attribute as shown in the following two tables:

Code	Customer type
PR	Private
PPM	Prepayment Meter
CO	Commercial
GO	Government
IN	Internal

Code	Tranche
FE	Franchise Electricity
PBI	Public Benevolent Institution
VE	Vacant Franchise Electricity – Lost Consumption
NB	Third Party Network Billing
T1	Tranche 1 (consume over 4,000,000 kWh)
T2	Tranche 2 (consume between 3,000,001 - 4,000,000 kWh)
T3	Tranche 3 (consume between 2,000,001 - 3,000,000 kWh)
T4CSO	Tranche 4 Community Service Obligation (consume between 750,001 – 2,000,000 kWh and charged via the pricing order)
T4CR	Tranche 4 Cost Reflective (consume between 750,001 – 2,000,000 kWh and individually contracted)
T5	Tranche 5 (consume between 160,001 – 750,000 kWh and individually contracted)
X5	Franchise (consume between 160,001 – 750,000 kWh and charged via the pricing order)

As RMS is a live system, it captures current information and does not capture historic values for certain customer attributes. Therefore, we have assumed that the customer type may change over time but it is not captured. In other words, for any National Metering Identifier (NMI) the customer type at the beginning of the period may be different to that at the end of the period and the dataset only has the current customer type. We have assumed that the current classification of the NMI has not changed over the reporting period.

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 we do not have any time of use network tariffs for our residential customers.
- those non-residential customers not on demand tariff or time of use tariff were customers with consumer type CO, GO and IN and tranche FE, PBI, T5, VE and X5.

Energy Delivery at Shoulder times & Controlled load energy deliveries (DOPED0205)

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 listed asset including the NBN Co Node street address and supply premise location, proposed unmetered usage based on NATA (National Association of Testing Authorities) testing (in watts), daily unmetered usage as kWh and the start date details. The purpose of the original spreadsheet was for billing so includes calculations of network and retail tariffs and charges.

Annual unmetered usage in kWh for all unmetered installations was calculated as:

$$\frac{\text{Watts x hours per day x days per year}}{1000}$$

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

For the 2005-06 to 2013-14 period this data was completed using the Annual Internal Statistics workbook. Data for 2014-15 was provided by Territory Generation, the sole supply of generation to the regulated network at that time and 2015-16 was provided by the Market Operator business section of Power and Water based on Market Settlements data

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 & Energy into DNSP network at Off-peak times from non-residential embedded generation (DOPED0403)

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 and tranches that were not related to not on demand tariff or time of use network tariffs.

Non-residential low voltage demand tariff customers energy deliveries & Non-residential high voltage demand tariff customers energy deliveries

The voltage at which each customer is connected is not recorded in the billing or metering systems, so 34 customer connections to the high voltage network were separately identified along with the date at which they connected to the high voltage network. All other customers were assumed to be connected to the low voltage network. Based on this the energy consumption dataset described above was used to report these variables.

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 (DOPED0206)* in Table 3.4.1.1.

4.1.3 Estimated and actual information

Information	Estimated and actual information
Total Energy Delivery (DOPED01)	This information is based on data from our systems and from external sources. Assumptions have been applied which may of material value. Consequently, the RIN defines this data to be estimated information.
Energy Delivery where time of use is not a determinant (DOPED0201)	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 (DOPED0203) & Controlled load energy deliveries (DOPED0205)	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 (DOPED0202) & Energy Delivery at Off-peak times (DOPED0204)	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 (DOPED0206)	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 (DOPED0301), Energy into DNSP network at Shoulder times (DOPED0302) & Energy into DNSP	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

Information	Estimated and actual information
network at Off-peak times (DOPED0303)	estimated information.
Energy received from major generator and other DNSPs not included in the above categories (DOPED0304)	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 (DOPED0401), Energy into DNSP network at Shoulder times from non-residential embedded generation (DOPED0402) & Energy into DNSP network at Off-peak times from non-residential embedded generation (DOPED0403)	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 (DOPED0404)	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 (DOPED0405), Energy into DNSP network at Shoulder times from residential embedded generation (DOPED0406) & Energy into DNSP network at Off-peak times from residential embedded generation (DOPED0407)	We do not have this information and have reported zero. This information does not relay 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 (DOPED0408)	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 (DOPED0501)	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 (DOPED0502)	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 (DOPED0503) & Non-residential high voltage demand tariff customers energy deliveries (DOPED0504)	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 (DOPED0505)	This information materially relies on data sourced externally and is therefore defined by the RIN as estimated information.

4.1.4 Source of the information

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.

4.1.5 Confidential information

Template 3.4.1 does not contain confidential information.

4.2 Template 3.4.2 - Customer Numbers

4.2.1 Consistency with the RIN

Appendix E Requirements	Consistency with requirements
Clause 3.43: *Workbook 2 – Economic benchmarking, regulatory template 3.4,* table 3.4.2 *Customer* numbers (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.
(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.
Clause 3.44: *Workbook 2 – Economic benchmarking, regulatory template 3.4,* table 3.4.2.1 Distribution *customer numbers* by *customer* type or class (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.
(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).
Clause 3.45: *Workbook 2 – Economic benchmarking, regulatory template 3.4,* table 3.4.2.2 Distribution *customer numbers* by location on the *network* (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.

4.2.2 Methodology and assumptions

For the entire reporting period, 2005-06 to 2016-17, we developed a customer number and energy consumption dataset collated from our 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 is discussed in our response to 4.2.1.

Residential customer numbers

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’.

Non-residential customers not on demand tariff customer numbers

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’.

Low voltage demand tariff customer numbers (DOPCN0103)

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’.

High voltage demand tariff customer numbers (DOPCN0104)

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’.

Unmetered Customer Numbers (DOPCN0105)

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 has been excluded in accordance with the RIN requirements. In contrast, the traffic light assets and NBN related assets have been reported as individual customers, which explains the increase in customers from 2015-16.

Other Customer Numbers (DOPCN0106)

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

Customers on CBD network (DOPCN0201), Customers on Urban network (DOPCN0202), Customers on Short rural network (DOPCN0203) and Customers on Long rural network (DOPCN0204)

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).

4.2.3 Estimated and actual information

This information in 3.4.2 is sourced from our 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, all information is defined by the RIN as estimated information.

4.2.4 Source of the information

Information	Source
Customer information	RMS
Customer energy information	RMS / MV90
Location type (feeder data)	GIS / Maximo

4.2.5 Confidential Information

Template 3.4.2 does not contain confidential information.

4.3 Templates 3.4.3.1 & 3.4.3.3 - Maximum demand at zone substation level

4.3.1 Consistency with the RIN

Appendix E Requirements	Consistency with requirements
Clause 3.46(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 3.46(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.

Appendix E Requirements	Consistency with requirements
Clause 3.47: 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.
Clause 3.49: 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.

4.3.2 Methodology and assumptions

For all templates 3.4.3, 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.

Raw System Annual Maximum Demand Variables (Coincident, Non-Coincident, MVA and MW)

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 estimated. The maximum demand values in MW were calculated based on the maximum demand values in MVA and the average 66 kV power factors from template 3.4.3.5.

E.g. DOPSD0101 = DOPSD0201 x DOPSD0311

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 assumed. For example. Cox Peninsula Zone Substation did not have data so information was taken from the 66kV connection point from the Darwin Zone Substation.

We engaged AEMO to carry out the demand forecast, which was based on historic data. Therefore the 2016-17 values were based on the values provided in AEMO's report.[3] Even though the 2016-17 values were prepared by AEMO, they were prepared consistently with the based on the same sources (i.e. Our SCADA and meter data)

Weather Adjusted System Annual Maximum Demand Variables (Coincident, Non-Coincident, 10% POE, 50% POE, MW and MVA)

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 assumed 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, which are 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 66 kV power factors from template 3.4.3.5.

[3] AERReportForPWC_V3 (D2017/485465)

4.3.3 Estimated and 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.

As noted above the MW values calculated in 3.4.3.1 were converted from MVA using the average 66kV power factors. As the MW values for each time value across the year was not considered this information is estimated as per the AER definitions.

We routinely perform weather correction to its demand data for planning purposes and it uses Bureau of Meteorology weather data. As the weather data is not materially dependant on our systems or other business records the weather corrected data is defined by the RIN as estimated information.

4.3.4 Source of the information

Information	Source
Non-coincident Summated Raw System Annual Maximum Demand	SCADA / Meter
Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SCADA / Meter / BOM weather data
Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SCADA / Meter / BOM weather data
Coincident Raw System Annual Maximum Demand	SCADA / Meter
Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SCADA / Meter / BOM weather data
Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SCADA / Meter / BOM weather data

4.3.5 Confidential information

Templates 3.4.3.1 and 3.4.3.3 do not contain confidential information.

4.4 Template 3.4.3.2 & 3.4.3.4 - Maximum demand at generation connection

These templates relate to annual system maximum demand characteristics at the Generation Connection Point.

4.4.1 Consistency with the RIN

Appendix E Requirements	Consistency with requirements
Clause 3.48: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.2 Annual system maximum demand characteristics at the generator connection point level – MW measure: Coincident and non-coincident maximum demands	For the generation connection point level MW in template 3.4.3.2, We have reported the unadjusted raw demands and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand as per Methodology and assumptions.

Appendix E Requirements	Consistency with requirements
must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	
Clause 3.50: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.4 Annual system maximum demand characteristics at the generator connection point – 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 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.

4.4.2 Methodology and assumptions

Raw System Annual Maximum Demand Variables (Coincident, Non-Coincident, MVA and MW)

For each generation connection point (shown below) in the Darwin-Katherine, Alice Springs and Tennant Creek systems, the raw adjusted maximum demand values in MVA from SCADA and metering data were summated at fixed time intervals for each reporting year.

System	Generator Connection Points
Darwin-Katherine	Berrimah Power Station
Darwin-Katherine	Channel Island Power Station
Darwin-Katherine	Katherine Power Station
Darwin-Katherine	Pine Creek Power Station
Darwin-Katherine	Weddell Power Station
Alice Springs	Brewer Power Station
Alice Springs	Owen Springs Power Station
Alice Springs	Ron Goodin (generators connected to 11 kV bus)
Alice Springs	Sadadeen (generators connected to 22 kV bus)
Alice Springs	Uterne Solar Power Station
Tennant Creek	Tennant Creek Power Station

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 raw unadjusted maximum demand data in MW was sourced as the raw unadjusted values in MW from the same time interval in which the MVA peaks occurred.

The following exceptions to the above methodology resulted from data issues we encountered in collating the generation data:

Where data was not available in MVA, MW values were converted to MW using an assumed power factor. Similarly, if MW values were not available, MVA values were converted to MW using an assumed power factor. The power factor used is 0.96. [4]

Where neither MW nor MVA values were available at the generator connection point, the data used was in the following order of preference:

- Next level of data was used. For example: Tennant Creek Power station in 2009 had no generation data so instead the summated feeder data is used (being a single power station system). Sadadeen generation connection point in 2005-12 calculated as the Alice Springs system load reduced by Brewer Power Station generation connection.
- Adjacent years peak demand for a single connection point. For example: Channel Island Power station 2006 maximum demand assumed to be the same as 2007.
- Berrimah Power Station was not included in any calculations because of limited SCADA data and it was not used as a system normal supply, rather it was only used under emergency and test conditions.
- The non-coincident and coincident maximum demand values (MVA & MW) were calculated by AEMO for the year 2016-2017. AEMO was engaged to develop our demand forecast which included the calculation of the MD values for 2016-17. These values were calculated consistently with the other values calculated by us.

Weather Adjusted System Annual Maximum Demand Variables (Coincident, Non-Coincident, 10% POE, 50% POE, MW and MVA)

As noted above, we undertake weather correction in relation to wet season data (November to March) as there is no correlation between weather and system demand in the dry season. For this reason, the maximum demand on our networks is assumed 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.

[4] 0.96 is the Darwin Katherine system average power factor during peak demands periods as per page 1, D2015/525150 NPR1522 Estimation of Power Factors for PWC Systems 2014-15

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, which are based on studies of the correlation between temperature increase in each region and the demand increase in that same region.

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.

The weather corrected maximum demand values in MW, were calculated using the weather corrected values in MVA and the average 66 kV power factors from template 3.4.3.5.

4.4.3 Estimated and actual information

Variable	Estimated or actual information
Non-coincident Summated Raw System Annual Maximum Demand	The MVA value is an actual value, calculated using data at each generation point to determine the annual maximum demand at that point. The maximum demand at each generation point is then summated to provide the non-coincident summated raw system annual maximum demand. The MW values are calculated by using an average system power factor of 0.96. They do not use a power factor for that specific time period as such. This value according to the RIN definitions is estimated.
Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	Values were calculated as described in 4.3.4.2 Methodology and assumptions. Bureau of Meteorology weather data was utilised, which is considered estimated as it is not our record.
Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	Values were calculated as described in 4.3.4.2 Methodology and assumptions. Bureau of Meteorology weather data was utilised, which is considered estimated as it is not our record.
Coincident Raw System Annual Maximum Demand	The MVA value is an actual value, calculated by summating data for each time interval across all generation points to determine the coincident raw system maximum demand. The MW values are calculated by using the MVA value in template 3.4.3.4 and an average system power factor of 0.96. They do not use a power factor for that specific time period as such. This value according to the RIN definitions is estimated.
Coincident Weather Adjusted System Annual Maximum Demand 10% POE	Values were calculated as described in 4.3.4.2 Methodology and assumptions. Bureau of Meteorology weather data was utilised, which is

Variable	Estimated or actual information
	considered estimated as it is not our record.
Coincident Weather Adjusted System Annual Maximum Demand 50% POE	Values were calculated as described in 4.3.4.2 Methodology and assumptions. Bureau of Meteorology weather data was utilised, which is considered estimated as it is not our record.

4.4.4 Source of the information

Information	Source
Non-coincident Summated Raw System Annual Maximum Demand	SCADA / Meter
Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SCADA / Meter / BOM weather data
Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SCADA / Meter / BOM weather data
Coincident Raw System Annual Maximum Demand	SCADA / Meter
Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SCADA / Meter / BOM weather data
Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SCADA / Meter / BOM weather data

4.4.5 Confidential information

Templates 3.4.3.2 and 3.4.3.4 do not contain confidential information.

4.5 Template 3.4.3.5 - Power Factor conversion

This template relates to Power Factor Conversion between MVA and MW

4.5.1 Consistency with the RIN

Appendix E Requirements	Consistency with requirements
Clause 3.51: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.5 Power factor conversion between MVA and MW: 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 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	Power factor has been calculated following the total MW divided by total MVA requirements as per Methodology and assumptions.

Appendix E Requirements	Consistency with requirements
divided by the total MVA. 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.	

4.5.2 Methodology and assumptions

Average Overall Network Power Factor Conversion between MVA and MW

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.

Average Power Factor Conversion for 11kV & 22kV Lines

Summated MVA and MW interval values were not available for 11 kV and 22 kV feeders. Given the data limitations, the 11 kV and 22 kV power factors were estimated based on the available SCADA/meter data for a sample of feeders at several zone substations. The power factor for 2016-17 was calculated at four 11 kV zone substations and three 22 kV zone substations. Power factors for 2009-10 and 2015-16 were calculated for four zone substations which were then used to provide a linear extrapolation between these years. Power factor prior to 2009-10 was assumed to be equivalent to 2009-10 power factors.

Average Power Factor Conversion for 66kV Lines

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.

Average Power Factor Conversion for 132kV Lines

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.

4.5.3 Estimated and actual information

Information	Estimated or actual information
Average overall network power factor conversion between MVA and MW	This data is materially dependant on SCADA and meter data and there are limited assumptions applied. Therefore, the RIN defines this as actual information.

Information	Estimated or actual information
Average power factor conversion for 11kV & 22kV lines	This data is materially dependant on SCADA and meter data and however as this data is based on an assumed sample of feeder data. This is considered to be estimated data because the power factors could be materially different depending on the selected sample chosen.
Average power factor conversion for 66kV lines	Values are actual from 2013-14 to 2016-17. Prior to this the SCADA system was different and values have been estimated (As described in 4.3.5.2 Methodology and assumptions).
Average power factor conversion for 132kV lines	Values are actual from 2013-14 to 2016-17. Prior to this the SCADA system was different and values have been estimated (As described in 4.3.5.2 Methodology and assumptions).

Despite the above classification of information as estimated or actual, there are a number of factors that should be noted.

Prior to 2013-14 data on transmission lines has not been easily retrieved from SCADA and often inaccurate. For this reason, the values prior to 2013-14 have been assumed as identical to 2013-14.

MW and MVAR data points at the feeder level have not previously been retrieved. The reasons for this are as follows:

- Availability of the data at feeder level; and
- due to capacitor banks being installed off the 11kV bus, zone substation data is not sufficient.

Power factor data on feeders has been available in more recent years as digital relays have been installed.

Previously generation/transmission/retail were all within the same corporation. We are now installing additional metering at the generation and zone substation level to ensure we now capture losses and this will assist in ensuring we have accurate MW and MVA at these levels also.

4.5.4 Source of the information

Item	Source
Average overall network power factor conversion between MVA and MW	SCADA / Meter
Average power factor conversion for 11 kV lines	SCADA / Meter
Average power factor conversion for 22 kV lines	SCADA / Meter
Average power factor conversion for 66 kV lines	SCADA / Meter

Item	Source
Average power factor conversion for 132 kV lines	SCADA / Meter

4.5.5 Confidential information

Template 3.4.3.5 does not contain confidential information.

4.6 Template 3.4.3.6 - Demand supplied MW

This template relates to demand supplied (for customers changed on this basis) for MW measures.

We do not charge customers based on MW and this table has been reported as zero.

4.7 Template 3.4.3.7 - Demand supplied MVA

This template relates to demand supplied (for customers charged on this basis) - MVA Measure

4.7.1 Consistency with the RIN

Appendix E Requirements	Consistency with requirement
Clause 3.52: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.6 Demand supplied (for customers charged on this basis) – MW measure: (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.
Clause 3.53: Workbook 2 – Economic benchmarking, regulatory template 3.4, table 3.4.3.7 Demand supplied (for customers charged on this basis) – MVA measure: (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'. (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. We measure the monthly maximum demand for customer on an MVA tariff. We have entered all maximum demand into the measured maximum demand variable.

Appendix E Requirements	Consistency with requirement
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.	

4.7.2 Methodology and assumptions

We extracted the maximum demand for 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.

4.7.3 Estimated and actual information

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

4.7.4 Confidential information

Templates 3.4.3.6 and 3.4.3.7 do not contain confidential information.

4.7.5 Source of the Information

The information was sourced from our metering system, MV90.

5. Template 3.5 – Physical assets

5.1 Templates 3.5.1, 3.5.2 and 3.5.3 - Capacity and public lighting

5.1.1 Consistency with RIN Requirements

Appendix E Requirements	Consistency with the Requirements
3.54 (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 regulated areas
3.54 (b) For 'Other overhead voltages' and 'Other underground voltages' PWC must add additional rows for voltages other than: (i) low voltage distribution; (ii) 11 kV; (iii) SWER (single wire earth return) (applicable to overhead only); (iv) 22 kV; (v) 33 kV; (vi) 66 kV; (vii) 132 kV.	We have no other voltages than those specified.
3.54 (c) PWC must specify the voltage for each 'other' voltage level. Circuit length	We have no other voltages than those specified.
3.55 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.

Appendix E Requirements	Consistency with the Requirements
3.56 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.
3.57 This information will be used to calculate an overall MVA x km 'carrying capacity' for each voltage 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 those years where there was a summer peak.	Noted but not applicable to 3.5.1.4.
3.58 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.	Not applicable to us.
3.59 (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 capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).	The distribution transformer capacity has been reported as instructed.
3.59 (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.
3.59 (c) Report transformer capacity owned by PWC; give nameplate continuous rating including forced cooling.	The transformer capacity has been reported as instructed.

Appendix E Requirements	Consistency with the Requirements
3.59 (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 in 5.5.1.
3.59 (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 in 5.5.1.
3.59 (f) When completing the templates for regulatory years subsequent to the 2012-13 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.
3.59 (g) Report the total capacity of spare transformers owned by PWC but not currently in use.	Spare capacity has been reported as instructed.
3.60 (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.
3.60 (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.
3.60 (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. 3.60 (d) For "Total installed capacity for second step transformation where there are two steps to reach	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. 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.

Appendix E Requirements	Consistency with the Requirements
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.	
3.60 (e) For "Total zone substation transformer capacity where there is only a single transformation to reach distribution voltage" (DPA0603) report total 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.	Transformer capacity has been reported as instructed for single step transformation sites
3.60 (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.
3.60 (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.

5.1.2 Methodology and assumptions

Template 3.5.1.1 – 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. The quantities used are the quantity of assets currently installed that were installed during or prior to the year in question. This results in a small understatement of the actual circuit length at year end, since asset replacements which occurred in prior years are effectively not counted. E.g. if a conductor was replaced in 2016-17, the table did not include the previous cable in the 2015-16 circuit lengths. The effort required to address this gap was not considered appropriate given the immaterial amount of error introduced by low historic volumes of conductor replacements.

The table below shows the mapping of the network segment in template 3.5.1.1 to the Asset Age Profile dataset.

Network Segment	Entity	Voltage (kV)	Type
Overhead low voltage distribution	21	≤0.415	Conductor
Overhead 2.2 kV	21	2.2	Conductor
Overhead 6.6kv	21	6.6	Conductor
Overhead 7.6 kV	21	7.6	Conductor
Overhead 11 kV	21	11	Conductor
Overhead SWER	21	22	SWER
Overhead 22 kV	21	22	<>SWER
Overhead 33 kV	21	33	Conductor
Overhead 44 kV	21	44	Conductor
Overhead 66 kV	21	66	Conductor
Overhead 110kV	21	110	Conductor
Overhead 132 kV	21	132	Conductor
Overhead 220kV	21	220	Conductor

It should be noted that where an asset's age was unknown, that asset has been assumed to be installed prior to 2008-09 for the volume at year end calculation, and has been excluded from the average age of asset group calculation.

Template 3.5.1.2 - Underground network circuit length at each voltage

The Methodology and assumptions for template 3.5.1.2 were the same as for 3.5.1.1 except that the cable dataset was used in place of the conductor.

Template 3.5.1.3 - 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.

The weighted average MVA for each voltage level was then calculated using the formula below:

$$Weighted\ average\ MVA\ capacity = \frac{\sum Conductor\ MVA.Meter}{\sum Conductor\ Length}$$

Template 3.5.1.4 - 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, except that some additional assumptions were made due to insufficient data:

- XLPE cables are assumed to be single core cables
- PILC cables are assumed to be three core cables
- 66kV ratings are based on their design ratings.

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 using the formula below:

$$Weighted\ average\ MVA\ capacity = \frac{\sum Cable\ MVA.Meter}{\sum Cable\ Length}$$

Template 3.5.2 - 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.

The methodology used to extract the capacity per year was the same as that described in section 5.1.1, except that a nominal amount of capacity was added each year to allow for quantities of transformers replaced each year. It was considered necessary to minimise the cumulative error introduced, since there was a relatively high volume of distribution transformer replacement in the 2005-06 to 2016-17 period. The amount of replaced capacity was calculated by taking an average of distribution capacity replaced each year in the capex backcasting model.

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 original installation dates for each customer were not known, so the earliest known date of a power connection at the address was used to obtain a financial year for the establishment of the HV connection. The transformer capacity of each customer was estimated by dividing their peak load by the capacity utilisation in RIN template 3.6.4 in the year of installation. 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 reviewing end of financial year stocktakes for the 2012-13 to 2016-17 periods and summing the distribution transformer capacity in each year. Prior to 2012-13 We did not have an internal store and inventory was managed by an external party, so spare capacity for those years is reported as zero.

Template 3.5.2 – Transformer Capacities – 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 (Internal Version Network Management Plan 2013 14 to 2018 19 - January 2017 Information Update (D2017/58809)).

The cold spare capacity of Zone Substation transformers were added to the total Zone Substation transformer capacity from 2010-2011 to 2016-2017. The cold spare capacities were obtained from the document “Power Transformer and Distribution Transformer Spare Capacity for EB RIN 3.5 (D2017/494020)”.

Template 3.5.3 – 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.

5.1.3 Estimated and actual information

The information in templates 3.5.1.1, 3.5.1.2, and 3.5.2 are estimated as defined by the AER’s RIN. The historical quantity of conductors, cables and distribution transformers is not recorded in our asset system. Further, 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.

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 (e.g. single core and three core cable). As such, some assumptions were made to determine the most likely cable ratings. Alternative assumptions may have resulted in materially different outcomes.

5.1.4 Source of the information

Information	Source
Total installed capacity for first step transformation where there are two steps to	Power and Water Corporation - Network Management Plan 2015-16 – January 2017 information update

Information	Source
reach distribution voltage	Power and Water Corporation - Network Management Plan (2013-14 – 2018-19)
Total installed capacity for second step transformation where there are two steps to reach distribution voltage	Power and Water Corporation - Network Management Plan 2015-16 – January 2017 information update Power and Water Corporation - Network Management Plan (2013-14 – 2018-19)
Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	Power and Water Corporation - Network Management Plan 2015-16 – January 2017 information update Power and Water Corporation - Network Management Plan (2013-14 – 2018-19)
Total zone substation transformer capacity	Power and Water Corporation - Network Management Plan 2015-16 – January 2017 information update Power and Water Corporation - Network Management Plan (2013-14 – 2018-19)

5.1.5 Confidential information

This template does not contain confidential information.

6. Template 3.6 – Quality of service

6.1 Templates 3.6.1 and 3.6.2 - Reliability and energy not supplied

6.1.1 Consistency with the RIN requirements

Appendix E Requirements	Consistency with the RIN requirements
3.61(a) Reliability data must be reported in accordance with the definitions provided in the AER's STPIS unless otherwise specified.	The information provided in Table 3.6 on 'Reliability' is consistent with the requirements and associated definitions.
3.61(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.	The outage data recorded by PWC is consistent with this AER requirement
3.61 (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.	The outage data recorded by Power and Water is consistent with this AER requirements
3.61(d) Excluded outages are defined in Appendix F.	Power and Water excluded interruptions described in Clause 3.3 (a) and (b) of the STPIS
3.62 (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 Power and Water is consistent with this AER requirement
3.62 (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
3.63(a) and 3.64(b) Report SAIDI and SAIFI in accordance with the definitions provided in Appendix F.	The outage data recorded by Power and Water is consistent with this AER requirement

Appendix E Requirements	Consistency with the RIN requirements
3.64(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
3.65(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) and (b) of the STPIS
3.65(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): (i) average consumption of the customers interrupted based on their billing history; (ii) feeder demand at the time of the interruption divided by the number of customers on the feeder; (iii) average consumption of customers on the feeder based on their billing history; (iv) average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder.	Power and Water estimated the customer demand in a region (Darwin, Katherine, Alice Springs, Tennant Creek) using feeder demand as recorded by SCADA records in 2016/17. This demand per customer was used as one of the inputs into energy not supplied calculations for all the years prior to and including 2016/17
3.65 (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
3.66 (a) System losses is the proportion of energy that is lost in distribution of electricity from the transmission network to PWC customers.	We have calculated this in accordance with the requirement. This is explained in the methodology section.
3.66 (b) PWC must report distribution losses calculated as per Equation 2.	We have calculated this in accordance with the requirement. This is explained in the methodology section.

6.1.2 Methodology and assumptions

Reliability (3.6.1)

Our system operators record outages manually in real time. The data is collected on an internal spreadsheet. This data is audited internally by our System Control staff on a monthly basis and considered as accurate as possible based on the limitations of the systems used to capture this data.

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 Power and Water network. These indices were calculated after excluding some interruptions as described in Clause 3.3 (a) of the STPIS.

The data required in EB RIN 3.6.1 were populated with the following outage-related data (recorded by System Control) that was obtained from the source as is: Date of event, Time of interruption, Asset ID, Average duration of sustained customer interruption.

In most cases the outage-related data was also used to provide the 'Number of customers affected by the interruption' as required in the RIN. However, in cases where this data was not provided, the customer count on an asset affected by the outage was obtained from GIS/ESRI.

The outage data recorded for the period up to 2012/13 was recorded only on feeder locations and the number of customers affected by the outage. This only took into account those customers affected by the outage and not necessarily the entire customers served by the feeder.

For the period after 2012/13, in addition to feeders, outages were also recorded on many other assets including distribution transformers, reclosers, switches, pole and fuses. This change in process occurred due to the change in systems used to collect outage data i.e. from FIS to Maximo (the Asset Management System).

In order 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 based 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.

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 approach followed to identify the MEDs is as follows:

- Starting with 2008/09, the exclusions allowed in line with Clause 3.3 (a) STPIS were applied and the MEDs were calculated using the 2.5 Beta Method described in IEEE Standard 1366
- When calculating the MEDs for the years after 2008/09, 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 2009/10, the data analysed excluded

all the days that have been identified as MEDs in the previous 5 years (2008/09-2005/04);

- Step b) was repeated for all the years, 2009/10 - 2016/17 (inclusive), and the Major Event Day Thresholds (TMED) applicable in each financial year were identified
- As required by Clause 3.64 (b) in Part C: Workbook 2 – Economic Benchmarking of RIN under Division 4 of Part 3 of the National Electricity (NT) Law, the MED threshold for 2015/16 was applied as the MED threshold for all years prior to and including 2015/16. The MED thresholds for 2016/17 were applied to 2016/17 only.

Any daily SAIDI value that exceeded the MED thresholds in d) was considered to be an MED and used in the AER submissions.

Energy not supplied (3.6.2)

The reliability data described in Template 3.6.1 (Reliability) was used as the main input into Template 3.6.2 (Energy not supplied). Other data was obtained from SCADA.

SCADA is able to record feeder demand every 30 minutes. These data were collated for the 2016/17 financial year for those feeders that were in service in 2016/17. The feeders in each of the four regions (Darwin, Katherine, Alice Springs, Tennant Creek) were used to calculate the average demand in each region.

The customer base in each of the four regions was obtained from the Retail Management System (RMS) on a monthly basis. The number of customers in each region was taken to be the average of the number of all customers supplied at the beginning of the reporting period and the number of all customers supplied at the end of the reporting period.

The average demand in a region together with the average customers in each region was used to estimate the average demand per customer in a region for 2016/17. It was then assumed that the aforementioned values apply in all the years prior to and including 2016/17. These 2016/17 data was linked to the outage data based on the region in which each outage occurred. Using the duration of an outage, the customers affected by the outage together with the demand per customer in a region the energy not supplied in each region was calculated and the energy not supplied as required in the RIN was obtained by summing the values from each region.

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

6.1.3 Estimated and actual information

The information for templates 3.6.1 and 3.6.2 is defined as actual based on AER definitions. The source data on outages is contained in an internal business record. We note that additional processes were used to derive some data but that the assumptions used would not yield materially different outcomes, and therefore is actual information.

6.1.4 Source of the information

Data	Source
Sustained outages	For information prior to 2012, the source was internal spreadsheets that collect information on outages recorded manually by system operators. Customer count on each feeder was obtained from FIS data. Outage data for the period after 2012/13 was sourced from the Asset Management System (Maximo), which was established during the 2012/13 financial year. The customer count on individual feeder was obtained from the GIS/ESRI 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. For the period after 2014/15 customer count was obtained every quarter from the GIS/ESRI and the average customer count was used to calculate reliability indices.

6.1.5 Confidential information

This template does not contain confidential information.

6.2 Template 3.6.3 - System losses

6.2.1 Consistency with RIN

AER requirement	Consistency with RIN requirement
3.65 (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
3.66 (a) System losses is the proportion of energy that is lost in distribution of electricity from the transmission network to PWC customers.	We have used this definition to address the question
3.66 (b) PWC must report distribution losses calculated as per Equation 2.	We have used the equation.

6.2.2 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, where

- Energy Lost = "Energy received from major generator 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 embedded generation" (template 3.4.1.3); minus "Total energy delivered" (template 3.4.1.)

- Total Energy Received = "Energy received from major generator and other DNSPs not included in the above categories" (template 3.4.1.2); plus "Energy received from embedded generation not included in above categories from non-residential embedded generation" (template 3.4.1.3) plus "Energy received from embedded generation not included in above categories from residential embedded generation" (template 3.4.1.4).

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

6.2.3 Estimated and 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, by definition, the resulting data is an estimate.

6.2.4 Source of the information

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

6.2.5 Confidential information

This template does not contain confidential information.

6.3 Template 3.6.4 - Capacity utilisation

6.3.1 Consistency with the RIN

Appendix E Requirements	Consistency with the RIN requirements
3.67 (a) 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.
3.67 (b) PWC must report the sum of non-coincident maximum demand at the zone substation level divided by summation of zone substation thermal capacity.	As noted in our methods and assumptions, we have applied this method.
3.67(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.

6.3.2 Methodology and assumptions

The capacity utilisation values were calculated based on the summation of non-coincident maximum demands at Subtransmission 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. Capacity utilisation data was sourced from the document "AERReportForPWC_V3 (".

6.3.3 Estimate and actual information

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

6.3.4 Source of the information

3.6.4 - Capacity Utilisation	Source
Overall utilisation	Power and Water Corporation - Network Management Plan 2015-16 – January 2017 information update Power and Water Corporation - Network Management Plan (2013-14 – 2018-19)

6.3.5 Confidential information

This template does not contain confidential information.

7. Template 3.7 – Operating environment

7.1 Template 3.7.1 – Density Factors

We have not completed the basis of preparation as we were not required to provide data.

7.2 Template 3.7.2 - Terrain Factors - Standard Vehicle Access

7.2.1 Consistency with the RIN requirements

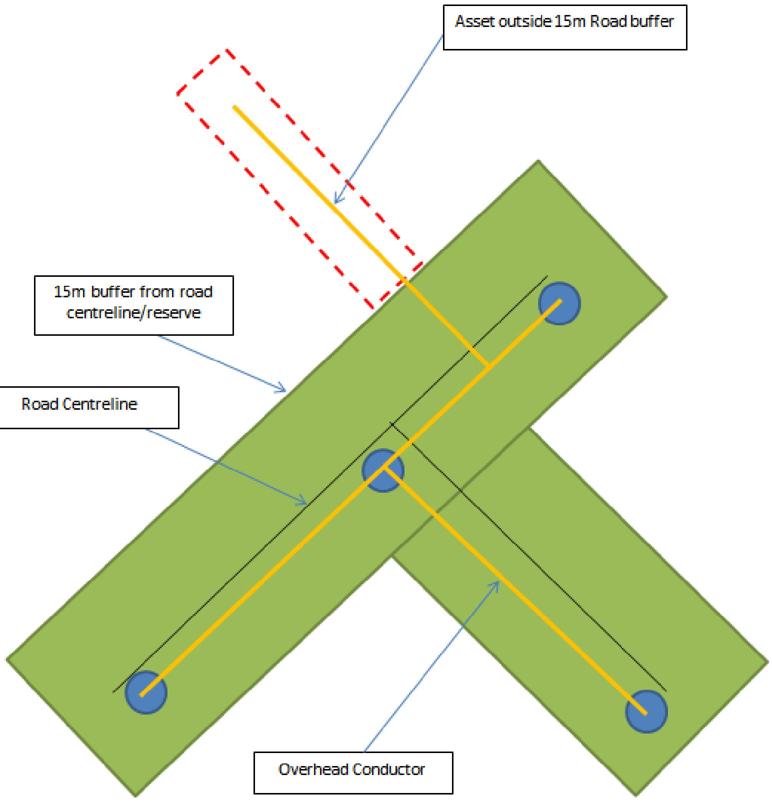
Appendix E Requirements	Consistency with the RIN requirements
3.68 (a) Complete table 3.7.2 in accordance with the definitions provided in Appendix F.	We have applied the definition in providing the data to the AER.
3.68 (b) If PWC has actual information, PWC must report all years of available data. 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 information. We have estimated the information consistent with the Methodology and assumptions below.

7.2.2 Methodology and assumptions

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. Therefore any of our network 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. The diagram below is a visual representation of this analysis, performed using SQL database scripting tool Safe Software FME. The output from this script is included in the source file “20170921 Determining Standard Vehicle Access 2016-17”.



Circuit lengths from GIS are valid for the financial year 2016-17 only. Scaling has been performed for previous years using the same method as for Route Line Length in Template 3.7.3 using age profile data for lines.

7.2.3 Estimated and actual information

Standard vehicle access is not calculated in business systems or historically reported. Its basis is a calculated route length for 2016-17 and assumptions about what parts of the network require 4WD access for a significant portion or all of the year in any year. Different assumptions would materially affect the calculation of this variable and is considered to meet the AER’s definition of estimated information.

7.2.4 Source of the information

The output from the GIS script and data used to scale for the previous years is included in the file referenced below.

Information	Source

Information	Source
Standard Vehicle Access Data Sheet	20170921 Determining Standard Vehicle Access 2016-17

7.2.5 Confidential Information

This template does not contain confidential information.

7.3 Template 3.7.3 - Service Area Factors – Route Line Length

7.3.1 Consistency with RIN requirements

Appendix E Requirements	Consistency with requirement
3.69(a) 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.

7.3.2 Methodology and assumptions

Historical route line length has not been previously calculated or reported by us. Route line length requires:

A. the length of service lines not to be counted;

B. the length of a span that shares multiple voltage levels is only to be counted once; and

C. the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

Clarification was sought from the AER in regards to (A) as we maintain vegetation on Service Lines to 2 metres within property boundaries. The response from the AER was:

> *Our preferred approach is that Power and Water excludes service lines from route line length. However, we have previously advised Power and Water that they may include service lines in their counts of 'total network spans' and 'vegetation management spans'. This reflects Power and Water's role in maintaining vegetation along these service lines and the difficulty for Power and Water to separately identify the service line component. We ask that Power and Water clearly identify in their RIN basis of preparation that these numbers include service lines and reasons for doing so.*

To calculate route line length for the 2016-17 year, and SQL data base script has been developed using SQL database scripting tool Safe Software FME to perform the following analysis of GIS data:

1. Calculate the length of service lines up to 2 metres within any property boundary,
2. Calculate the length of the network as per (B); and (C)

A visual representation of (B) is shown below.

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 2016-17 only. This calculation is in the "Route Length and Standard Vehicle Access data sheet".

Using the 2016-17 total route length as a baseline, route length for prior years are scaled back based on additions to the age profile for overhead circuit length. It is assumed the additions to overhead circuit length are proportional to additions to network route length. The percentage variation year by year is calculated in the Network Scaling tab of the Asset Age Profile sheet, and a copy exists in the "Route Length and Standard Vehicle Access data sheet" where the scaling calculation is applied to the base year. This tab is a copy from the Age Profile source data used for Category Analysis RIN data.

7.3.3 Estimated and actual information

Estimated and actual information	Justification
3.7.3 Route Line Length 2016/17	Route line length for 2016-17 has been calculated using business systems and is considered actual information under the RIN definition.
3.7.3 Route Line Length prior to 2016/17	All information in years prior to 2016-17 has not been reported historically by the business, and we do not have the data required to perform this calculation. Calculations for prior years are based on an assumption that the asset age profile accurately reflects changes to route length year by year. Other assumptions or methodologies could be

Estimated and actual information	Justification
	applied and would materially affect the values and is considered to meet the RIN definition of estimated information.

7.3.4 Source of the Information

The output from the GIS script and data used to scale for the previous years is included in the file referenced below.

Information	Source
Total Route Length and Standard Vehicle Access Data Sheet	20170921 Determining Standard Vehicle Access and route line length 2016-17 for table 3.7.2 and 3.7.3 EB RIN
Vegetation Zone Route Length and Total Number of Spans	Overhead Route Lengths 16_17 Ver 3
Asset Age Profile	Asset Age Profile - Asset Data and Charts for Asset Management Plans
Route length SQL script output	20170824 - GIS Report - Overhead Route Lengths - Updated to Calculate Route Length for Transmission

7.3.5 Confidential Information

This template does not contain confidential information.