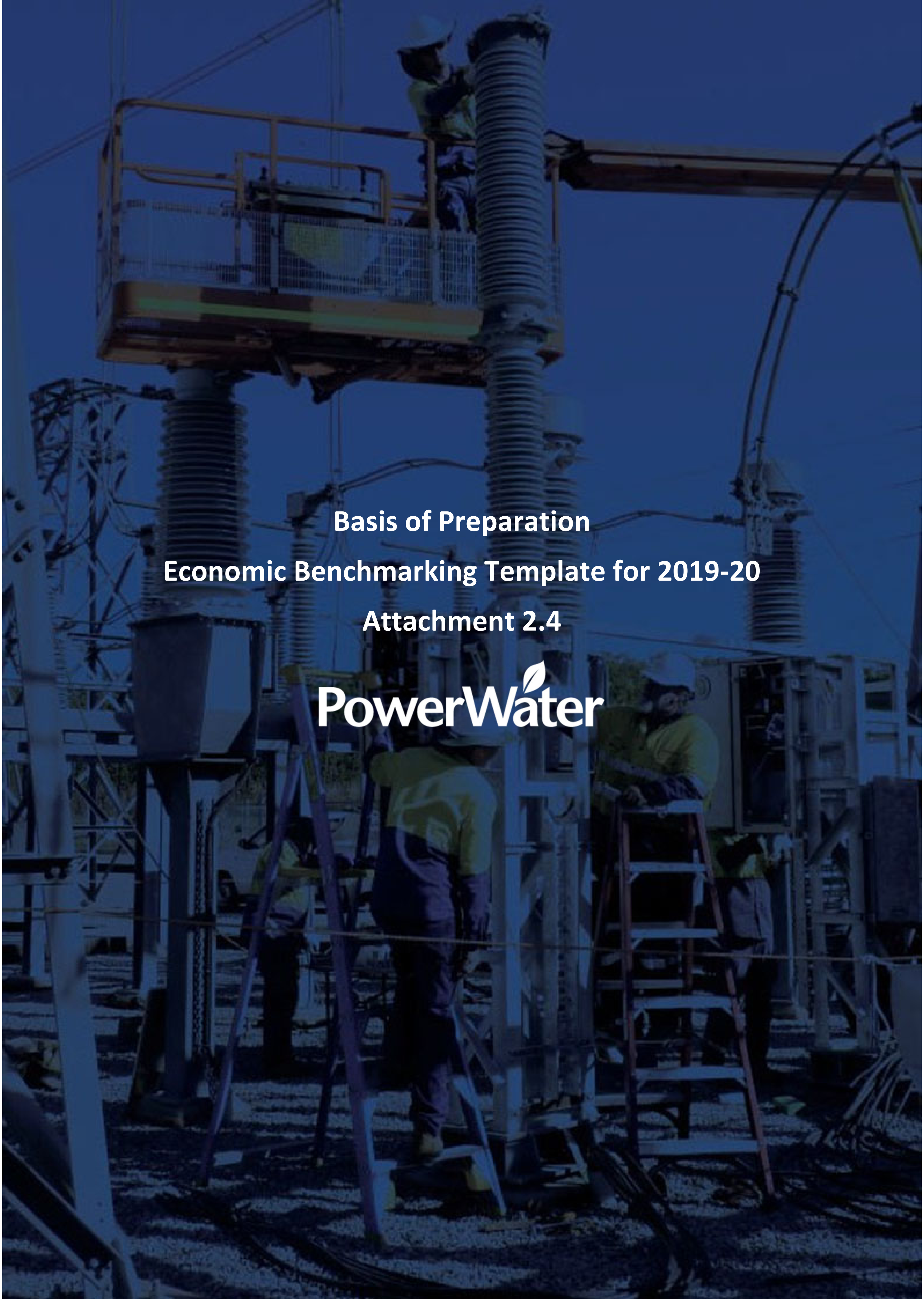

Basis of Preparation

Economic Benchmarking Template for 2019-20

Attachment 2.4

Table of contents

Template - 3.1 Revenue

Table 3.1.1 - REVENUE GROUPING BY CHARGEABLE QUANTITY

Table 3.1.2 - REVENUE GROUPING BY CUSTOMER TYPE OR CLASS

Source of Data

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

Estimated or actual information

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

Methodology and assumptions

Background

There were substantive changes in the pricing arrangements for network services in 2019-20, reflecting the change in regulatory arrangements applying from 1 July 2019.

While some adjustments were made, our methodology to reporting revenues associated with these services did not change substantially to previous years.

Power Services revenue accounts for standard control services and alternative control services were extracted from Power Services regulated Profit and Loss for 2019-20. In the instances revenue categories based on AER service classifications could not be directly sourced from the P&L. We used supporting information on consumption and demand data from MV90 and RMS and trial balance listings from FMS to allocate revenue to the most appropriate revenue categories in these instances. The total revenue amounts reconciled to Power Services regulated Profit and Loss for 2019-20.

Confidential Information

Information in this template is not confidential.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 3.1: PWC must report revenues split in accordance with the categories in Economic benchmarking workbook. The Economic benchmarking workbook requires PWC to report revenues by chargeable quantity (table 3.1.1) and by type of connected equipment (table 3.1.2). The total of revenues by chargeable quantity must equal the total of revenues by type of connected equipment because they are simply two different ways of disaggregating total revenue.	Each row in tables 3.1.1 and 3.1.2 has been reported for 2019-20 and the annual totals are equal as required.
Clause 3.2: PWC must report revenues split into standard control services and alternative control services in accordance with the service classifications for the most recent completed regulatory year.	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined it its Framework and Approach paper. Therefore, the revenue data has been split into SCS and ACS in accordance with the AER's classification of services in its Framework and Approach Paper.
Clause 3.3: PWC must enter '0' into cells that have no effect on the revenues PWC. For instance, if PWC does not use a shoulder period for energy delivery charges then the amount of revenue reported for the variable would be '0'.	All unused cells have '0' entered.
Clause 3.4: Revenues should be able to be reconciled to reported revenues in the regulatory accounting statements for each regulatory year.	Revenue data on tables 3.1.1 and 3.1.2 reconciles to our audited financial accounts.
Clause 3.5: Revenues reported [in template 3.1.1] must be allocated to the chargeable	We allocated revenue to the most appropriate category based on the type of charge and tariff.

quantity: (a) Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by PWC to customers (the chargeable quantities are the variables DREV0101- DREV0112); (b) Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other Sources' (DREV0113); and (c) 'Revenue from unmetered supplies' is the same for table 3.1.1 as for table 3.1.2, so they must be equal.	Data for revenue from unmetered supplies in table 3.1.1 equals that in table 3.1.2.
Clause 3.6: Economic benchmarking workbook, regulatory template - 3.1, table 3.1.2-Revenue grouping by customer type or class: (a) PWC must allocate revenues to the customer type that most closely reflects the customers from which PWC received its revenue; (b) Revenues that PWC cannot allocate to the customer types DREV0201-DREV0205 must be reported against 'Revenue from other customers' (DREV0206).	We allocated revenue to the most appropriate category based on the type of charge and tariff, which in turn relates to specific customer types.

Table 3.1.3 - REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES

Source of Data

N/A

Estimated or actual information

N/A

Methodology and assumptions

N/A

Confidential Information

N/A

Consistency with RIN requirements

N/A

Template - 3.2 Operating Expenditure

Table 3.2.1 - CURRENT OPEX CATEGORIES AND COST ALLOCATIONS

Table 3.2.2 - OPEX CONSISTENCY - CURRENT COST ALLOCATION APPROACH

Source of Data

Operating expenditure for distribution services was sourced from the Trial balance. Labour cost adjustment was sourced from Maximo (Asset Management System). Connections expenditure in ACS was sourced from the Category Analysis RIN Template 4.3.

Estimated or actual information

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

Methodology and assumptions

General methodology

Our 'Power Services' operating unit provides all direct and some indirect distribution services provided within Power and Water Corporation. Other operating units that provide distribution services indirectly are Finance/Corporate, Customer Service Centre and System Control. The costs attributed to Power Services in the Audited Statutory Accounts are related to electricity distribution services. The total operating cost of the regulated distribution services is included wholly within Power Services' accounts, which includes its portion of the costs allocated from Finance/Corporate, Customer Service Centre and System Control costs.

The Trial Balance for Power Services is the source of the operating expenditure reported in the RIN for distribution services. The Power Services' 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: Standard Control Distribution Services, Alterative Control Services - Metering (Types 1 to 6), Alternative Control Services - Fee Based Service, and Alternative 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 AER approved Cost Allocation Method (CAM). In summary, the CAM requires:

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

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

Labour recovery adjustments

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

Capitalisation of indirect costs and unallocated costs

We capitalise corporate and network overhead accounts for regulatory purposes in proportion to the ratio of direct capex to total direct costs (as described in the methodology for 2.10). If the ratio changes, the fraction of unallocated costs capitalised also changes. This is provided for in our approved regulatory CAM.

Opex for Network Services

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

1. ACS metering costs - these were identified by work orders and business unit costs;
2. ACS fee and quoted services - these were identified by work orders and business unit costs;
3. Unregulated activities (street lighting and remote communities related services) - these 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.
5. 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 and 291, 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. 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.

Opex for Public Lighting

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

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

Opex for Transmission Connection Point Planning

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

Confidential Information

This template does not contain confidential information.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements

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

for the most recent completed regulatory year. Economic benchmarking workbook, regulatory template 3.2, table 3.2.2 Opex consistency --- current cost allocation approach:	classification outlined it its Framework and Approach paper. We have applied the approved CAM and applied the Framework and Approach service classifications.
Clause 4.6 (a): This table is intended to collect consistent opex line items for economic benchmarking. Network services opex is requested as this is the core service which we intend to benchmark. Other services are collected so that their impact on productivity can be assessed and they can be incorporated or excluded from the services being benchmarked if necessary.	Network Services opex has been reported as equal to SCS opex as it is assumed to not include metering, connections or public lighting.
Clause 4.6 (b): The opex categories in this table are not intended to be mutually exclusive or collectively exhaustive. This means that the totals of opex in this table may be greater or less than PWC's actual opex. Further, opex may be double counted within the line items.	We have reported these categories in total with opex for major generator connection point planning assumed to be included in Network Services opex, otherwise there is no double-counting of opex.
Clause 4.6 (c): Opex must be prepared in accordance with PWC's cost allocation method and the service classifications for the most recent completed regulatory year.	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined it its Framework and Approach paper. We have applied the approved CAM and applied the Framework and Approach service classifications.

Table 3.2.4 - OPEX FOR HIGH VOLTAGE CUSTOMERS

Source of Data

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

Estimated or actual information

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

Methodology and assumptions

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

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

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

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

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

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

Template - 3.2.3 Provisions

Table 3.2.3 - PROVISIONS

Source of Data

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

Estimated or actual information

The information provided is actual. All the data in this template is materially dependent on our trial balances. However, the last step in the methodology is to apportion the provisions data into SCS and then 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.

Methodology and assumptions

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

- Extracted the financial data that applied to the provision of distribution services. Our statutory accounts ensure all costs of the electricity network - regulated areas, including overheads are recorded in Entity 21, known as "Power Services- Regulated". Utilising this extract was the simplest way to isolate 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 Services - Regulated. The information reconciles back to the trial balance and the audited year-end reconciliation.

- Established the amounts used during the year for "Power Services - Regulated". This information is provided by NT Department of Corporate and Information Services (DCIS) through a Personnel Information and Payroll System (PIPS) report.

- Established the amounts added during the year for "Power Services - Regulated".

- Ensured the opening balance plus the additions and less the amounts used are equal to the closing balance.

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

Provisions for Long Service Leave and Recreation Leave

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

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

- Long Service Leave: Current Long Service Leave Provision (67-014), Long Service Leave Payment in Lieu (67-688), Non-Current Long Service Leave Provision (82-806),

- Recreation Leave: Current Recreation Leave Provision (67-013), Rec Leave Payment in Lieu (67-686), Rec Leave Cash Up (67-687) Rec Leave Loading (67-015), Leave Fares (67-685)

The amounts used for long service leave and recreation leave provisions were calculated using the payroll report (PIPS) for 2019-2020 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 Services- Regulated entity.

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

Provision for Fringe Benefits Tax

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

The amount used is the actual FBT Return lodged and paid to the Australian Taxation Office (ATO) during the year. In addition, since the FBT year runs from 1 April to 31 March, the amount used also includes an accrual for the first quarter of the next FBT year ending 31st March 2021. The calculation is based from the most recently lodged FBT Return - divided by twelve then multiplied by three (months).

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

Provision for Payroll Tax

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

Additions to provision constitute the monthly accrual for NT payroll tax. The Calculation is made by summing up the wages paid to employees that are subject to payroll tax (i.e. salary, allowances, leave provisions, fringe benefits and superannuation) less any applicable exemptions (i.e. exemption for graduates and apprentices and workers compensation). The total is then multiplied by the 5.5% NT payroll tax rate. The amount used is the actual monthly NT payroll tax payments made during the year. Since lodgment and payment for payroll tax is done a month after, payroll tax for the month of June is paid the following year.

Allocation method

The total for each provision for Power Services - Regulated is split between CAPEX and OPEX. The CAPEX portion was calculated using the proportion of total labour cost used for capital projects. The proportion of standard control services in both OPEX and CAPEX is calculated using the proportion to the total labour costs (OPEX and CAPEX) used for standard control services.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 4.8(a): Financial information on provisions relating to standard control services must be reported in accordance with PWC's cost allocation method and the service classifications for the most recent completed regulatory year.	Our AER approved CAM allocates the costs of providing distribution services into the services classified by the AER in its Framework & Approach. It should be noted that the approved CAM does not include a methodology to allocate provisions data. The allocation of the provision amounts into the SCS has been performed

	consistently with the proportion of total labour costs used for SCS as discussed in the methodology.
Clause 4.8(b): Financial information on provisions should be able to be reconciled to the reported amounts for provisions in the regulatory accounting statements for each regulatory year.	PWC are unable to fulfil this requirement due to provisions not being reported in our regulatory accounts.
Clause 4.8(c): PWC must report financial information for each of its individual provisions. A provision is an account which records a specific present liability of an entity to another entity. Examples of provision accounts include employee entitlements, doubtful debts and uninsured losses. PWC must complete the table for each individual provision and must add rows as necessary to the template for this purpose.	We have reported our individual provisions, being provisions for the liabilities of Long Service Leave, Recreation Leave, Fringe Benefits Tax, Payroll Tax. We do not have any other provision accounts associated with Distribution Services.
Clause 4.8(d): For each additional provision specify the name of the provision and add variable codes for line items. A letter or letters must be added to the end of each variable code link it to the provision. For example, the variable codes for the first additional provision would be DOPEX0301A to DOPEX0312A, variable codes for the second would be DOPEX0301B to DOPEX0312B and the variable codes for the 28th provision would be DOPEX0301AA to DOPEX0312AA.	The names are as follows: 1. Long Service Leave - DOPEX03A to DOPEX0314A 2. Recreation Leave (includes Recreation Leave, Recreation Leave Loading and Recreation Leave Fares - DOPEX03B to DOPEX0314B 3. Fringe Benefits Tax - DOPEX03C to DOPEX0314C 4. Payroll Tax - DOPEX03D to DOPEX0314D

Template - 3.3 Assets (RAB)

Table 3.3.1 - REGULATORY ASSET BASE VALUES

Source of Data

Actual additions and disposals are sourced from our financial accounts and align with the tables in Template 8.2 of the Annual RIN response for the 2019-20 and prior years. Asset write-offs (journal entries to the P&L) are excluded. This is consistent with the RIN requirement of costs only recognised as incurred. Other values are sourced from the 2013-14 external valuation report and the Roll Forward Models for previous and current regulatory control periods. Where available, Roll Forward Models are sourced from determinations made by the Utilities Commission (UC) or the Australian Energy Regulator (AER).

Estimated or actual information

This information is sourced from our financial accounts. Therefore, this information is defined by the RIN to be actual information. We have made estimates for allocations of RAB, remaining asset life, and average of asset life consistent with the RIN instructions.

On this basis, we consider the information meets the definition of actual.

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

Methodology and assumptions

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

For others, these variables are calculated in accordance with the RIN requirements, a 2013-14 external valuation report, and the Roll Forward Models for previous and current regulatory control periods.

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

Other limitations include:

- Allocations are needed to split the RAB for connection services from the SCS RAB
- An accounting approximation is used to determine the weighted average remaining life
- An average of the asset life used by other networks when completing the equivalent Economic Benchmarking RIN tables was used for the standard lives, and
- Although prepared consistent with past AER practice and requirements included in the National Electricity Rules for the Northern Territory (NT NER), the SCS and ACS metering Roll Forward Models for the 2019-24 regulatory control period have not yet been reviewed or adopted by the AER.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 5.1: PWC must report RAB values in accordance with the standard approach and the Assets (RAB) financial reporting framework. This is a standard approach that must be used for RAB disaggregation to be followed by all Distribution Network Service Providers (DNSPs) (the Standard Approach).	The values reported in Template 3.3 are based on the standard approach.
Clause 5.7: RAB assets must be reported inclusive of dual function assets that provide standard control services.	We do not own any dual function assets, so none have been included.
Clause 5.8: The Assets (RAB) financial reporting framework: Standard control services, RAB financial information must reconcile to:	The jurisdictional regulator (the Utilities Commission, or UC), 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

(i) For years prior to any AER determination of RAB values, determinations in relation to RAB values made by the previous jurisdictional regulator unless the PWC has had the RAB 'revalued' in the backcast period. In this case standard control services, RAB financial information must reconcile to RAB values of a "rolled back" RAB prepared in accordance with the RAB framework; or	identified, which resulted in the RAB being overstated in the UC determination. The NT NER (the Rules) were subsequently 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 rollback is not expected to exactly reconcile with the jurisdictional regulator's published determination. The RAB reflects the AER's Final Determination that was released in April 2019. The RAB for 2014-15 to 2018-19 has been reconciled to the Roll Forward Model received in that determination.
(ii)For years where the AER has not made a decision on values for the RAB, RAB values must be prepared in accordance with the RAB framework. In this circumstance, actual additions (recognised in the RAB) and disposals must reconcile to amounts reported in the annual financial statements.	The AER has not yet decided values for the RAB for the 2019-20 year, with its decision not expected until April 2024. In anticipation of that decision, PWC has prepared two versions of the Roll Forward Model - one for each of SCS and ACS metering - for the 2019-24 regulatory control period. To do this we: • started with Version 3 of the AER's Roll Forward Model (published on its website) • populated it with starting inputs from its latest determination for the 2019-24 period (including the cost of debt update for the 2020-21 year) • input actual inflation for the year to December 2019 (published by the Australian Bureau of Statistics), and

	• input actual additions, capital contributions and disposals for the 2019-20 year as included in Tables 8.2.4, 8.2.5, and 8.2.6 of the Annual RIN response templates for that year. 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 have 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 and ACS metering RAB were automatically (i.e. via formula) adjusted up where necessary to ensure that balances for individual assets did not become negative as part of the roll-back.
Clause 5.9: Closing value in Workbook 2 - Economic benchmarking, regulatory template 3.3, tables 3.3.1 and 3.3.2 is derived from the sum of the opening value; Inflation addition; straight-line depreciation; actual additions (recognised in RAB) and disposals. Straight-line depreciation and disposals should be entered as negative numbers.	The closing value has been calculated as the sum of the opening value, inflation, depreciation, additions, and disposals. Where we have received a capital contribution for capital expenditure amounts added to the RAB we have also deducted the capital contribution amount received.

Clause 5.15: PWC must report totals of RAB financial information for all years in this table. The total for the RAB financial information will reconcile with the RAB financial information provided in table 3.3.2.	RAB totals for all years have been provided in table 3.3.1 with the methodology set out below. These values reconcile with those provided in 3.3.2.

Table 3.3.2 - ASSET VALUE ROLL FORWARD

Source of Data

Actual additions and disposals are sourced from financials accounts, but significant modifications have been applied and align with the tables in Template 8.2 of the Annual RIN response for the 2019-20 and prior years. All other values have been sourced from the 2013-14 external valuation report and the Roll Forward Models for previous and current regulatory control periods. Where available, Roll Forward Models are sourced from determinations made by the Utilities Commission (UC) or the Australian Energy Regulator (AER).

Estimated or actual information

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

The opening value is calculated in accordance with the RIN requirements and the 2013-14 external valuation report. Other values are source from the Roll Forward Models for previous and current regulatory control periods. This information is not materially dependent on sourced from any of our systems or other records used in the normal course of business. Therefore, this information is estimated information.

The information has been sourced as follows:

- RAB movements:
  - Po Adjustment Model FINAL (March 2009).xls
  - RY10 to RY13- UC: 2014 NPD - Initial RP - Attachment 16 - RFM Commission preferred.xls
  - AER - PWC 2019-24 - FD - RFM - April 2019.XLSM
  - PWC - Roll-Forward Model - SCS - 2019-24 - 2019-20 Actuals - DRAFT.xlsm
  - PWC - Roll-Forward Model - ACS - 2019-24 - 2019-20 Actuals - DRAFT.xlsm

- Connection CAPEX: Gross CAPEX - Category Analysis RIN - Table 2.1.1
- Connection CAPEX: Capital contributions - Category Analysis RIN - Table 2.1.7.

Methodology and assumptions

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

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

- Link historical and forecast RAB values for SCS and ACS based on RAB asset classes within:
    - Roll Forward Models adopted by the UC and AER in their respective determinations, and
    - Draft Roll Forward Models prepared by PWC for the 2019-24 regulatory control period that will eventually form part of PWC's distribution proposal for the 2024-29 regulatory control period.
- Determine what proportion of SCS values relate to network services activities.
- Allocate RAB asset class values into EB RIN categories.
- Calculate the RAB values by category.
- Calculate the associated standard and remaining lives by EB RIN category.

Methodology detail: Historical RAB Values for SCS and ACS

We are required to populate RAB values, split by Economic Benchmarking categories for 2019-20. To do this, the model also includes historical data from 2005-06 to 2018-19.

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 RAB asset class for the categories (or block) in the list below. The list highlights the treatment of each block within the worksheet highlighting which items are sourced from other workbooks and which items link out to key outputs of the model.

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

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

For the 2019-20 year, the number of asset classes for the SCS and ACS RABs increased from that applying previously due to the change in regulatory control period. As such, both the

"Input_RAB_SCS" and "Input_RAB_SCS" sheets were adjusted - from the version of the "EB RIN RAB Allocation Model" used in prior years - to incorporate those new asset classes.

Methodology detail: Network Services RAB

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

The metering RAB is classified as ACS and is therefore treated separately (and picked up in the "Input_RAB_ACS" sheet). We do not have a RAB relating to public lighting or fee and quoted based services.

As we do not have a separate RAB for connection services the NS RAB was estimated by:

- Quantifying net connection related CAPEX for 2008-2017.
- Quantifying net CAPEX for asset classes which include connection CAPEX for 2008-2017.
- Calculating the proportion of connection related CAPEX over 2008-2017.
- Determining the estimated connection RAB by asset category.
- Calculating the NS RAB by subtracting the estimated connection RAB from the total SCS RAB.

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

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

Methodology detail: Allocation from RAB asset classes to EB RIN categories

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

Service Classification	RAB Asset Class	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
SCS, NS, and ACS	Property Leases	Other assets with long lives
SCS, NS, and ACS	Fleet leases	Other assets with short lives
SCS, NS, and ACS	Buildings	Other assets with long lives
SCS and NS	In-house software	Other assets with short lives
ACS	Mechanical meters - General	Meters
ACS	Mechanical meters - Prepaid	Meters
ACS	Electronic Meters	Meters
ACS	Metering Communications	Other assets with short lives

ACS	Metering - Dedicated CTs and VTs	Other assets with long lives
ACS	Metering - Non-network Other	Other assets with long lives

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

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

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

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

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

Methodology detail: Calculating the RAB Values by EB RIN category

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

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

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

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 5.2: Where PWC believes it has sufficient information to provide a consistent RAB disaggregation into the RAB assets in the Assets (RAB) worksheet that better reflects the values of those assets (the Optional Additional Approach), it may also provide this in a separate Excel worksheet.	We have not used an alternative approach.
Clause 5.3: In both cases we will require the provision of the basis of preparation for the allocated RAB values detailing the calculations undertaken. The disaggregated RAB values developed using the Optional Additional Approach must be reported in accordance with tables 3.3.2	We have used the standard approach as explained in the methodology section below.

and 3.3.3. In both cases PWC must provide a supporting worksheet detailing the calculations undertaken.	
Clause: 5.4 Substation land must be included in the 'substation asset' category. Separate values for substation land may be provided in accompanying documentation to the notice response.	Substation land has been included in the substation asset category. No separate values are provided in accompanying documentation.
Clause 5.5: In completing the Economic benchmarking workbook, regulatory template 3.3 PWC must report metering assets in accordance with the service classifications for the most recent completed regulatory year	The AER advised PWC after the issuing of the EB RIN that PWC must apply the AER's approved 2019-24 service classification outlined in its Framework and Approach paper. Type 1 to 6 metering is classified as an 'Alternative Control Service' as per the Framework & Approach paper and the final determination published by the AER in April 2019. As explained in the methodology section below, we have reported the RAB values for these services in the ACS table only.
Clause 5.7: RAB assets must be reported inclusive of dual function assets that provide standard control services.	We do not own any dual function assets, so none have been included.
Clause 5.8: The Assets (RAB) financial reporting framework: Standard control services, RAB financial information must reconcile to: (i) For years prior to any AER determination of RAB values, determinations in relation to RAB values made by the previous jurisdictional regulator unless the PWC has had the RAB 'revalued' in the back cast period. In this case standard control services, RAB financial information must reconcile	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. The Rules were subsequently 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 rollback is

to RAB values of a "rolled back" RAB prepared in accordance with the RAB framework; or	not expected to reconcile with the jurisdictional regulator's determination. The RAB reflects the AER's Final Determination that was released in April 2019. The RAB for 2014-15 to 2018-19 has been reconciled to the Roll Forward Model received in that determination.
(ii) For years where the AER has not made a decision on values for the RAB, RAB values must be prepared in accordance with the RAB framework. In this circumstance, actual additions (recognised in the RAB) and disposals must reconcile to amounts reported in the annual financial statements.	The AER has not yet decided values for the RAB for the 2019-20 year, with its decision not expected until April 2024. In anticipation of that decision, PWC has prepared two versions of the Roll Forward Model - one for each of SCS and ACS metering - for the 2019-24 regulatory control period. To do this we: • started with Version 3 of the AER's Roll Forward Model (published on its website) • populated it with starting inputs from its latest determination for the 2019-24 period (including the cost of debt update for the 2020-21 year) • input actual inflation for the year to December 2019 (published by the Australian Bureau of Statistics), and • input actual additions, capital contributions and disposals for the 2019-20 year as included in Tables 8.2.4, 8.2.5, and 8.2.6 of the Annual RIN response templates for that year. 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 have 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 backcast SCS and ACS metering RAB were automatically (i.e. via formula) adjusted up where necessary to ensure that balances for individual assets did not become negative as part of the roll-back.
Clause 5.9: Closing value in Economic benchmarking workbook, regulatory template 3.3, tables 3.3.1 and 3.3.2 is derived from the sum of the opening value; Inflation addition; straight-line depreciation; actual additions (recognised in RAB) and disposals. Straight-line depreciation and disposals should be entered as negative numbers.	The closing value has been calculated as the sum of the opening value, inflation, depreciation, additions, and disposals. Where we have received a capital contribution for capital expenditure amounts added to the RAB we have also deducted the capital contribution amount received.
Clause 5.10: Direct attribution to the AER's economic benchmarking RAB asset classes: (a) Where RAB financial information can be directly allocated to the RAB assets (as per the definitions in Appendix F) it must be directly allocated to those RAB assets. Financial information can be directly allocated to RAB asset class where that financial information relates to assets that wholly fall within the definition of that RAB asset class. For example, financial data	Where we were able to directly allocate financial values to the RAB categories (i.e. RAB assets) we have done so.

associated with poles can be directly allocated to overhead distribution assets (wires and poles).	
Clause 5.11: Where direct attribution to the economic benchmarking asset classes is not possible: (a) RAB financial information that cannot be directly allocated to a single RAB asset category should be allocated in accordance with the RAB allocation	Where we could not wholly allocate financial information to the RAB categories (i.e. RAB assets), we have used the RAB allocation approach. We have described this in the methodology section below.
Clause 5.16: Economic benchmarking workbook, regulatory template 3.3, table 3.3.2 Asset value roll forward: (a) PWC must report RAB financial information broken down in accordance with the RAB assets as per the definitions in Appendix F. 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.

Table 3.3.3 - TOTAL DISAGGREGATED RAB ASSET VALUES

Source of Data

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

Estimated or actual information

The values are calculated as an average of the opening and closing balances for each EB asset category. For the reasons noted above, some information used to determine those balances (i.e. that sourced from the Roll Forward Models) are considered estimates. Therefore, the opening, closing and average balances are also considered to be estimates.

Methodology and assumptions

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

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

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

and closing values in table 3.3.2 for the relevant categories.	

Table 3.3.4 - ASSET LIVES (ESTIMATED RESIDUAL SERVICE LIFE)

Table 3.3.4 - ASSET LIVES (ESTIMATED SERVICE LIFE OF NEW ASSETS)

Source of Data

The estimated service lives of new assets are sourced from the economic benchmarking RIN prepared by other Australian distribution network service providers (DNSPs) for the 2015-16 financial year or the 2016 calendar year and published on the AER's website. These are same values used by PWC in RIN responses for prior years.

The estimated residual service life is calculated using values in Table 3.3.2.

Estimated or actual information

All information in Table 3.3.4 is based on the asset lives from other DNSPs or from the RAB values sourced from Roll Forward Models and reflected in Table 3.3.2. Therefore, it is not materially dependent on our systems or other business records and is, by definition, estimated information.

Methodology and assumptions

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 DNSP peers.

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

The estimated residual service lives have been calculated using an accounting proxy method. In general, the residual service life for each category is calculated by dividing the closing balance for the period by the straight-line depreciation value for the period. The values in forecast periods are expected to change as the ratio of closing balances to straight-line depreciation varies slightly year on year as forecast values are replaced with actual values. The estimated values for each EB category are bounded so that they do not exceed the estimated service of new assets for that category nor fall below zero - both outcomes that are considered unfeasible.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 5.18: Workbook 2 - Economic benchmarking, regulatory template 3.3, table 3.3.4 Asset lives: a. In relation to table 3.3.4.1 'Asset lives - estimated service life of new assets' and table 3.3.4.2 'Asset lives - estimated residual service life', PWC must report asset lives for all RAB assets in accordance with the definitions provided in the notice. b. Where the categories comprise of a number of assets, asset lives for the whole category must be calculated by weighting the lives of individual assets within that category. Weightings must be calculated in order of preference.	We have complied with the AER's instructions as demonstrated in our methodology and assumptions.
Clause 5.19 a. Equation 1 Weighted average asset life calculation: Weighted average asset life for assets in category Where: *n* is the number of assets in category j *xi,j* is the value of asset i in category j *ELi,j* is the expected life of asset i in category j *RCj* 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	We have complied with the AER's instructions as demonstrated in our methodology and assumptions.

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 5.20: Workbook 2 - Economic benchmarking, regulatory template 3.3, table 3.3.4.1 Asset lives - estimated service life of new assets: a. PWC must report the current expected service life of new assets in this table. The expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. b. This may not align with the asset's financial or tax life.	We have developed the estimated service lives of new assets based on DNSP Peer comparisons as detailed in section 3.3.4 above.
Clause 5.21: Workbook 2 - Economic benchmarking, regulatory template 3.3, table 3.3.4.2 Asset lives - estimated residual service life: a. PWC must report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409) will	The estimated residual service lives have been calculated using an accounting proxy method set out in section 3.3.4 above.

deliver the same effective service as that asset class did at its installation date.	

Template - 3.4 Operational Data

Table 3.4.1 - ENERGY DELIVERY 1

Source of Data

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

Estimated or actual information

The information is estimated. Below we identify what items are estimate, and the justifications:

- Total Energy Delivery (DOPED01) - This information is based on data from our systems and from external sources. Assumptions have been applied which may be of material value.
- Energy Delivery at On-peak times (DOPED0202) & Energy Delivery at Off-peak times (DOPED0204) - We have entered zeros as we do not provide an on-peak or off-peak period tariff for energy delivery. Therefore, the information does not materially rely on any system or records.
- 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.
- Energy Delivery to unmetered supplies (DOPED0206) - This information materially relies on data sourced externally.
- Energy into DNSP network at On-peak times (DOPED0301), Energy into DNSP network at Shoulder times (DOPED0302) & Energy into DNSP network at Off-peak times (DOPED0303) - We do not have this information and have reported zero. This information does not rely on our systems or records.
- 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.

- 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 rely on our systems or records.
- Other Customer Class Energy Deliveries (DOPED0505) - This information materially relies on data sourced externally.

Methodology and assumptions

General methodology

For 2019-20, we developed a customer number and energy consumption dataset that was collated from metering system (MV90) and billing systems (RMS). Certain data relating to remote communities were excluded because the remote community supply networks are not classified as "distribution services" for the purpose of the RIN and are therefore not regulated. This was done in two steps:

The data was restricted to only include customer installations in the Darwin - Katherine, Alice Springs and Tennant Creek regulated systems using the following District Codes: AA - Alice Springs, A28 - Alice Springs Outstations, DA - Darwin, D26 - Wagait Beach, D27 - Dundee, D28 - Namarada, D29 - Beatrice Hill, DB2 - Adelaide River, DB3 - Batchelor, KA - Katherine, KB1 - Pine Creek, KB2 - Mataranka, KB3 - Larrimah, TA - Tennant Creek.

There are 18 remote community networks that our regulated networks supply. Each of these remote communities are considered to be individual networks. Therefore, for the following remote community District Codes, consumption for all installations was included but the community was treated as one single customer: A02 & AB3 - Santa Teresa / Ltyentye Purte, K03 & KB9 - Beswick, A03 & AB8 - Hermannsburg, K04 & KB8 - Barunga, A10 & AB4 - Amoonguna, K10 & K33 - Djilkminggan, A20 & AB0 - Wallace Rockhole, K14 & K34 - Binjari, A24

& AB6 - Iwupataka / Jay Creek, K18 & K35 - Kybrook Farm, AB9 - Tjuwanpa, K22 & K36 - Jodetluk, D17, D31 & DB1 - Belyuen, K28 - Rockhole, D25 - Darwin Outstations, T01 & TB3 - Ali Curung, D30 & D32 - Acacia Larakia and TB4 - McLaren Creek.

Only 17 of the 18 communities listed have consumption recorded during the 2019-20 period. There are no installations with the District Area Code D25. The dataset classified all consumption data with a customer type attribute as follows: PR - Private, PPM - Prepayment Meter, CO - Commercial, GO - Government, IN - Internal.

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

Due to the change in the Standard Control Services Network charging implemented on 1 July 2019, a new BI report had to be created to report on NMI's based on the tariff they were charged at. The report included demand and kWh for all active NMI's with meter readings throughout the year. The data was split based on the tariff they were charged.

For the larger consumers with higher demand amounts, the data was sourced from the MV90 system as in previous years. Due to the change in charging, Tariff 3 LV smart meters are now charged demand charges however due to the number of customers in this category (nearly 19,000) it would be onerous to obtain the demand readings (which would be minimal for this customer class) and update the data manually.

This change has also impacted the classification of the energy used by customer types and the number of customers in each class.

3.4.1 - Energy Delivery

DOPED01 - Total Energy Delivered

Total Energy Delivered was calculated as the sum of the energy delivery variables in Table 3.4.1.1.

3.4.1.1 - Energy grouping - delivery by chargeable quantity.

Energy Delivery at On-peak times & Energy Delivery at Off-peak times (DOPED0202 & DOPED0204)

Due to the change in Network charging, no customers are charged energy based on either on-peak or off-peak energy delivery. This has been reported with zeros.

Energy Delivery at Shoulder times (DOPED0203) & 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 to unmetered supplies (DOPED0206)

Unmetered consumption consists of traffic lights, National Broadband Network (NBN) assets, CCTV (from 2018-19 on) and Streetlights (from 2019/20).

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. This information is collected internally when new NBN assets are created, the information includes the asset number, address and region and the wattage of each site.

CCTV began billing in Q2 of 2018/19. Assets are stored in the GIS (Geographical Information System) and reported quarterly for billing purposes.

Streetlight data was provided by PWC Power Services staff, running a data report form the GIS. The data is reported quarterly for billing purposes.

Annual unmetered usage in kWh for all unmetered installations was calculated as: (Watts x Hours per day x days per year)/1000

Watts x hours per day x days per year

1000

Traffic lights, NBN assets and CCTV run 24 hours per day. Streetlights are programmed to run for 12 hours per day, from 6pm to 6am.

3.4.1.2 - Energy received from major generators and other DNSPs by time of receipt.

The Wholesale Market Operator section of Power and Water settles the market with data provided by all Generators licensed to operate in the market. This data is used as the embedded generation from non-residential generation in the regulated network

Energy into DNSP network at On-peak times (DOPED0301), Energy into DNSP network at Shoulder times (DOPED0302) and Energy into DNSP network at Off-peak times (DOPED0303).

We do not record energy received from Generators by time of generation. Therefore, these variables have been reported as zero values.

3.4.1.3 - Energy received into DNSP system from embedded generation by time of receipt.

Energy into DNSP network at On-peak times from non-residential embedded generation (DOPES0401), 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 record energy received from embedded generation by time of generation. Therefore, these variables have been reported as zero values.

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 record energy received from embedded generation by time of generation. Therefore, these variables have been reported as zero values.

3.4.1.4 - Energy Grouping

Other Customer Class Energy Deliveries (DOPED0505)

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.

Confidential Information

There is no confidential information in this template

Consistency with RIN requirements

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 bill on shoulder, on peak or off peak periods under the new charging structure shoulder, peak and off peak 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 bill on shoulder, on peak or off peak periods under the new charging structure shoulder, peak and off peak 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 is not possible to allocate the energy received into on- peak, shoulder and off-peak times.	We have reported Energy received from major generators and other DNSPs not included in the above categories (DOPED0304) for energy delivery that was not charged for peak, shoulder or off-peak periods.

Clause 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, shoulder 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	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.

category breakdown must be consistent with the customer types reported in table 3.4.2.1.	

Table 3.4.1 - ENERGY DELIVERY 2

Source of Data

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

Estimated or actual information

The information is actual. Below we identify what items are material and the justifications:

- 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.
- Energy received from TNSP and other DNSPs not included in the above categories (DOPED0304) - This information is sourced from our records without any significant assumptions applied.
- 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.
- 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.
- Residential customers energy deliveries (DOPED0501) - This is based on our systems and records and does not contain any significant assumptions.
- 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.
- 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.

Methodology and assumptions

General methodology

For 2019-20, we developed a customer number and energy consumption dataset that was collated from metering system (MV90) and billing systems (RMS). Certain data relating to remote communities were excluded because the remote community supply networks are not classified as "distribution services" for the purpose of the RIN and are therefore not regulated. This was done in two steps:

The data was restricted to only include customer installations in the Darwin - Katherine, Alice Springs and Tennant Creek regulated systems using the following District Codes: AA - Alice Springs, A28 - Alice Springs Outstations, DA - Darwin, D26 - Wagait Beach, D27 - Dundee, D28 - Namarada, D29 - Beatrice Hill, DB2 - Adelaide River, DB3 - Batchelor, KA - Katherine, KB1 - Pine Creek, KB2 - Mataranka, KB3 - Larrimah, TA - Tennant Creek.

There are 18 remote community networks that our regulated networks supply. Each of these remote communities are considered to be individual networks. Therefore, for the following remote community District Codes, consumption for all installations was included but the community was treated as one single customer: A02 & AB3 - Santa Teresa / Ltyentye Purte, K03 & KB9 - Beswick, A03 & AB8 - Hermannsburg, K04 & KB8 - Barunga, A10 & AB4 - Amoonguna, K10 & K33 - Djilkminggan, A20 & AB0 - Wallace Rockhole, K14 & K34 - Binjari, A24 & AB6 - Iwupataka / Jay Creek, K18 & K35 - Kybrook Farm, AB9 - Tjuwanpa, K22 & K36 - Jodetluk, D17, D31 & DB1 - Belyuen, K28 - Rockhole, D25 - Darwin Outstations, T01 & TB3 - Ali Curung, D30 & D32 - Acacia Larakia and TB4 - McLaren Creek.

Only 17 of the 18 communities listed have consumption recorded during the 2019-20 period. There are no installations with the District Area Code D25. The dataset classified all consumption data with a customer type attributes as follows: PR - Private, PPM - Prepayment Meter, CO - Commercial, GO - Government and IN - Internal.

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

Due to the change in the Standard Control Services Network charging implemented on 1 July 2019, a new BI report had to be created to report on NMI's based on the tariff they were charged at. The report included demand and kWh for all active NMI's with meter readings throughout the year. The data was split based on the tariff they were charged.

For the larger consumers with higher demand amounts, the data was sourced from the MV90 system as in previous years. Due to the change in charging, Tariff 3 LV smart meters are now charged demand charges however due to the number of customers in this category (nearly 19,000) it would be onerous to obtain the demand readings (which would be minimal for this customer class) and update the data manually.

This change has also impacted the classification of the energy used by customer types and the number of customers in each class.

3.4.1 - Energy Delivery

3.4.1.1 - Energy grouping - delivery by chargeable quantity.

Energy Delivery where time of use is not a determinant (DOPED0201)

Due to the change in Network charging structure, this variable is no longer applicable and has therefore been reported with zeros.

3.4.1.2 - Energy received from major generators and other DNSPs by time of receipt.

The Wholesale Market Operator section of Power and Water settles the market with data provided by all Generators licensed to operate in the market. This data is used as the embedded generation from non-residential generation in the regulated network

Energy received from TNSP and other DNSPs not included in the above categories (DOPED0304).

Data is provided by Generators to the Market Operator in order for them to settle the market. The data consists of monthly PPP (Pool Price Point) reads from Generators across the Northern Territory that is sent out from the connection point.

3.4.1.3 - Energy received into DNSP system from embedded generation by time of receipt.

Energy received from embedded generation not included in above categories from non-residential embedded generation (DOPED0404)

Embedded generation from non-residential generation comprises two sources;

Energy received from generation facilities with a nameplate capacity below 1 MW is included in non-residential embedded generation customers'. The Wholesale Market Operator provided data from all Generators licensed to operate in the market. One site meets criteria to be included as a generator in this category and their generation amounts are separated from other generators.

Photovoltaic (PV) export data was produced for all electricity installations located on regulated grids that had a PV metering set up. Remotely read interval meters show export consumption as a negative value and manually read accumulation PV meters give the export consumption as positive values. The values reported accounted for this to ensure the total energy received was reported correctly. Finally, the customer type was used to extract only the non-residential customers' data.

Energy received from embedded generation not included in above categories from residential embedded generation (DOPED0408)

Photovoltaic (PV) export data was produced for all electricity installations located on regulated grids that had a PV metering set up. Remotely read interval meters (Meter Register 3, Register Content 1A) show export consumption as a negative value and manually read accumulation PV meters (Meter Register 23, Register Content 103) 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.

3.4.1.4 - Energy Grouping

Residential customers energy deliveries (DOPED0501)

This variable was completed from the energy consumption dataset described above. It is the sum of any customer identified as residential (customer types PR and PM) regardless of meter type (accumulation or interval).

Non-residential customers not on demand tariffs energy deliveries (DOPED0502)

This variable was completed from the energy consumption dataset described above, as the consumption of non-residential customer types (customer types CO, GO and IN) that have accumulation meters so were billed on Tariff 2 under the network charging structure. These are the only non-residential customers not charged on a demand tariff.

Non-residential low voltage demand tariff customers energy deliveries (DOPED0503)

Under the new Networks charging structure, customers in the Low Voltage category are divided into those that use more than 750MWh annually (Tariff 5 LV Majors Tariff) and those that use less (Tariff 3 LV Smart Meter Tariff). Both categories are added together to complete the entry for this variable.

Non-residential high voltage demand tariff customers energy deliveries (DOPED0504)

High Voltage customers are identified as those that have a meter with a rating of 4000 or higher and have been categorised into two Network charging tariffs dependent on annual consumption. Tariff 6 HV Minors tariff groups customers that use less than 750MWh per year. Tariff 7 HV Majors encompasses the customers that do use over 750MWh per year. These two categories are added together to complete the entry for this variable.

Confidential Information

There is no confidential information in this template

Consistency with RIN requirements

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:	Energy delivered has been reported at the charging location based on amount billed.

(a) Energy delivered is the amount of electricity transported out of PWC's network in the relevant regulatory year (measured in GWh). It must be the energy metered or estimated at the customer charging location rather than the import location from the TNSP. Energy delivered must be actual energy delivered data, unless this is unavailable. Where actual information is not available for the most recent reporting period, energy delivery data for that period may be reported on an accrual basis.	
(b) Peak, shoulder and off-peak periods relate to PWC's own charging periods.	Energy delivered for the reporting period has been based on our peak, shoulder and off-peak periods applied for billing purposes. We do not bill on shoulder, on peak or off peak periods under the new charging structure shoulder, peak and off peak 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 bill on shoulder, on peak or off peak periods under the new charging structure shoulder, peak and off peak 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 is not possible to allocate the energy received into on- peak, shoulder and off-peak times.	We have reported Energy received from major generators and other DNSPs not included in the above categories (DOPED0304) for energy delivery that was not charged for peak, shoulder or off-peak periods.
Clause 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, shoulder 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.

Table 3.4.2 - CUSTOMER NUMBERS

Source of Data

The two primary sources of information for both Table 3.4.1 - Energy Delivery and Table 3.4.2 - Customer Numbers are MV90 and RMS. These datasets contain information on customer numbers, consumption, demand and export of PV. Calculations and assumptions have been applied to this source data.

Data on location type (feeder data) was provided by Power Services and sourced from GIS and Maximo.

Estimated or actual information

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

Methodology and assumptions

General methodology

For 2019-20, we developed a customer number and energy consumption dataset that was collated from metering system (MV90) and billing systems (RMS). Certain data relating to remote communities was excluded because the remote community supply networks are not classified as "distribution services" for the purpose of the RIN and are therefore not regulated. This 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'. Due to the change in Standard Control network charging structure, the numbers for Residential customers are the sum of the IES communities (refer to the basis of preparation for Template '3.4.1 Energy Delivery' on how the 17 communities were identified), plus NMI's billed on Tariff 1 - Residential Tariff plus NMI's billed on Tariff 3 - LV Smart Meter Tariff that are identified as PR (Private) Residential consumer types.

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'. This class of customer was obtained from those billed on Tariff 2 - Non-Residential Tariff. Due to the change in the Standard Control network charging structure, this number was a lot less that previous years due to the change in classification.

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'. The numbers in this section are comprised of the Tariff 3 - LV Smart Meter tariff NMI's identified as Non-Residential added to the Tariff 5 - Low Voltage NMI's where annual consumption is less than 750MWh. Due to the change in the Standard Control network charging structure, this number was has increased from previous years due to the change in classification.

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'. Under the Standard Control Service Network charges, these were customers billed on Tariff 6 - High Voltage Minors Tariff and Tariff 7 - High Voltage Majors Tariffs.

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 as a 'customer' has been excluded in accordance with the RIN requirements. In contrast, the traffic light assets, NBN related assets and CCTV assets have been reported as individual customers.

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)

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

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with requirements
6.6 (a) Distribution customers for a regulatory year are the average number of active National Meter Identifiers (NMIs) in PWC's network in that year (except for unmetered customer numbers). Each NMI is counted as a separate customer. The average is calculated as the average of the number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Both energised and de-energised NMIs must be counted. Extinct NMIs must not be counted.	We have captured all active customer connections, being those that are energised and de-energised but not those that are extinct. Customer numbers have been counted based on NMIs so each NMI is a customer.
6.6 (b) For unmetered customers, the customer numbers are the sum of connections (excluding public lighting connections) in PWC's network that do not have a NMI and the energy usage for billing purposes is calculated using an assumed load	We have not counted street lighting assets as individual customers. However, NBN, CCTV and traffic signals have been counted as individual customers for each connected.

profile (examples include bus shelters, security lighting and traffic signals where not metered). Public lighting connections must not be counted as unmetered customers.	
6.7 (a) PWC must report customer numbers in accordance with the categorisation as per the definitions provided in Appendix F.	We have reported customer numbers in accordance with the definitions provided in Appendix F of the RIN.
6.7 (b) PWC must report customers against 'Other customer numbers' (DOPCN0106) only when customers cannot be allocated to the other customer classes (DOPCN0101-DOPCN0105).	We have reported customers against 'Other customer numbers' (DOPCN0106) only when customers could not be allocated to the other customer classes (DOPCN0101-DOPCN0105).
6.8 (a) PWC must report customer numbers in accordance with the category definitions provided in Appendix F. The locations are: CBD, urban, short rural and long rural.	We have reported customer numbers in accordance with the definitions provided in Appendix F of the RIN.

Table 3.4.3 - SYSTEM DEMAND 1

Source of Data

The information was sourced from PWC's metering system (MV90) and billing system (RMS)

Estimated or actual information

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

Methodology and assumptions

For all High Voltage customers (above and below 750mwh annual usage) and for Low Voltage customers who use over 750mwh annually the data for the demand amount was sourced from MV90 reporting. With the change in billing structure of the Standard Control Services, all customers with Smart Meters may now be charged a demand charge ($/kVa) for the period 1 October - 31 March. Due to the number of customers it would be arduous to gather data for the approximately 19,000 customers form MV90 in the same way, so their demand amounts were reported from RMS using BI reporting.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
Clause 6.9 (a): Tables 3.4.3.1 to 3.4.3.4 must be completed in accordance with the definitions in Appendix F. PWC must provide inputs for these cells if it has calculated historical weather adjusted maximum demand.	We have applied the definitions in Appendix F and inputted these cells where it has calculated historical weather adjusted maximum demand.
Clause 6.9 (b): Where PWC does not calculate weather adjusted maximum demands it may estimate the historical weather adjusted data.	We calculate the weather adjusted maximum demands. As this data is calculated with data obtained outside of our systems, it is considered estimated based off RIN definitions.
Clause 6.10: Workbook 2 - Economic benchmarking, regulatory template 3.4, table	For the zone substation level MW in template 3.4.3.1, We have reported the actual raw

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.	demands (not weather normalised) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand as per Methodology and Assumptions section.
Clause 6.11: Economic benchmarking workbook, regulatory template 3.4, table 3.4.3.2 Annual system maximum demand characteristics at the generator connection point level - MW measure: (a) Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	For the generation connection point level MW in template 3.4.3.2 for Darwin Katherine and Alice Springs systems, we have reported the actual raw demands (not weather normalized) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand as per Methodology and Assumptions section. For the generation connection point level MW in template 3.4.3.2 for Tennant Creek system, we have reported the actual raw adjusted demands (not weather normalized) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand as per Methodology and Assumptions section. This is mainly 22 kV distribution feeder data was used, due to corrupted generation data in Tennant Creek system
Clause 6.12: Workbook 2 - Economic benchmarking, regulatory template 3.4, table 3.4.3.3 Annual system maximum demand characteristics at the zone substation level - MVA measure:	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.

Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	
Clause 6.13: Economic benchmarking workbook, regulatory template 3.4, table 3.4.3.4 Annual system maximum demand characteristics at the generator connection point - MVA measure (a) Coincident and non-coincident maximum demands must be reported raw (or unadjusted) and weather adjusted at the 10% and 50% POE levels.	For the generator connection point level in Darwin Katherine and Alice Springs systems, 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. For the generator connection point level in Tennant Creek system , we have reported the actual raw adjusted demands (not weather normalised) and weather adjusted (10% and 50% POE) coincident and non-coincident maximum demand in template 3.4.3.4. This is mainly 22 kV distribution feeder data was used, due to corrupted generation data in Tennant Creek system
Clause 6.14: Economic benchmarking, regulatory template 3.4, table 3.4.3.5 Power factor conversion between MVA and MW: 1. PWC must report the power factor to allow for conversion between MVA and MW measures for each voltage. If both MVA and MW throughput for a network are available then the power factor is the total 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 has been calculated following the total MW divided by total MVA requirements as per Methodology and Assumptions section.

power factor conversion (DOPSD0301) is the total MW divided by the total MVA. (b) If either the MW or MVA measure is unavailable the average power factor conversion can be calculated as an approximation based on best engineering estimates.	

Table 3.4.3 - SYSTEM DEMAND 2

Source of Data

The following information was sourced from SCADA and Meter data, together with Bureau of Meteorology (BOM) weather data.

Estimated or actual information

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

POE 50 and POE 10 weather corrected maximum demand values were calculated using actual maximum demand data and the maximum temperatures retrieved from Bureau of Meteorology website. The weather corrected maximum demand data is actual information, as the maximum temperature data from BOM website is routinely downloaded and stored in our internal record keeping system "CM9".

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

Methodology and assumptions

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

Zone substation

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

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

The method of adjusting for switching transfers only uses MVA values. As such the MW values are calculated using the average Zone Substation power factors.

Generation Connection Point

The annual coincident maximum demand in MVA was calculated as the maximum of these summated values for each fixed time interval over the year. The non-coincident maximum demand in MVA was calculated as the sum of the largest recorded demand for each generation connection point for Darwin Katherine and Alice Springs systems. Tennant Creek Zone Substation maximum demand in MVA was calculated based on the 22kV distribution feeder data, as the generation data was corrupted.

The annual coincident maximum demand in MW was calculated as the maximum of these summated values for each fixed time interval over the year. The non-coincident maximum demand in MW was calculated as the sum of the largest recorded demand for each generation connection point for Darwin Katherine and Alice Springs systems. Tennant Creek Zone Substation MW values were calculated based on MVA and average power factor at Tennant Creek Zone Substation.

Weather correction

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

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

- Darwin Airport weather station for Darwin-Katherine system

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

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

For all zone substations, we undertake weather correction for every raw adjusted demand in MVA for every interval of the year. The weather corrected maximum demand values in MW were calculated using the weather corrected values in MVA and the average Zone Substation power factors.

For all generation connection points (Darwin Katherine and Alice Springs systems), we undertake weather correction for every raw unadjusted demand in MVA and MW for every interval of the year.

For Tennant Creek system, we undertake weather correction for every raw adjusted demand in MVA (based on 22kV feeder data) for every interval of the year. Then we calculate MW using weather corrected MVA and average power factor at Tennant Creek Zone Substation.

Power Factor conversion

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

- The average power factors for 11 kV and 22 kV lines were calculated using the summated MW divided by summated MVA. All data for these calculations was extracted from SCADA/meter data.
- The average power factor for 66kV lines was based on the power factor at the 'injection points' rather than at each individual 66kV line because both MVA and MW data for 66kV lines was not available. The power factor at the injection points was calculated using the summated MW divided by the summated MVA. The source data for these calculations is SCADA/meter data.

- The average power factor for 132kV lines was based on MVA and MW values at the injection ends of the 132kV line (i.e. Channel Island Power Station, Katherine Power Station and Pine Creek Power Station). The source data for these calculations is SCADA/meter data.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with requirement
6.15(a) PWC is only required to complete this table if it charges customers for maximum demand supplied. If PWC does not charge customers on this basis then PWC should enter '0'. 6.15 (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.
6.16(a) PWC is only required to complete this table if it charges customers for demand supplied. If PWC does not charge customers on this basis then PWC must enter '0'. 6.16(b) PWC must report maximum demand amounts for customers that are charged based upon their maximum demand as measured in MVA. Where PWC cannot distinguish between contracted and measured maximum demand,	We measure the monthly maximum demand for customer on an MVA tariff. We have entered all maximum demand into the measured maximum demand variable. We can distinguish between contracted and measured demand.

demand supplied must be allocated to contracted maximum demand.	

Template - 3.5 Physical Assets

Table 3.5.1 - NETWORK CAPACITIES 1

Table 3.5.2 - TRANSFORMER CAPACITIES 1

Source of Data

The data has been sourced as follows

- Cable and Conductor Ratings - We have used the data warehouse values (based on the Sincal Power System software).
- Asset Age Profile - We have used the same sources as the Category Analysis RIN (template 5.2)
- HV Customer Installed Capacity - We have used HV customers installed capacity and estimated opex
- Cold Spare Capacity - Extracted from Maximo
- Zone substation transformer capacities - Extracted from Maximo

Estimated or actual information

The information in templates 3.5.1.1 and 3.5.1.2 is actual as defined by the AER's RIN. The quantities of cables and conductors are taken directly from our asset system.

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 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

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 3.5.2 - 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. A small number of distribution transformers have unknown capacity. These were allocated an average capacity and included in the calculation of total installed capacity.

We do not have any distribution transformer cold capacity. The spare capacity was calculated by summing the capacity of spare distribution transformers in stores.

Template 3.5.2 - Transformer Capacities - Zone Substation Transformer Capacity

The transformer capacities at Subtransmission Substations and Zone Substations were taken from Maximo.

The cold spare capacity was calculated by summing the capacity of spare power transformers in stores, and is included in the total transformer capacity.

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.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
7.1 (a) PWC must report against the capacity variables for its whole network. In this context the network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. Network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	The following have been excluded from the volumes, in accordance with the instructions: • Services • Protection, communications and control cables • Streetlight cables and conductors Cables and conductors in unregulated areas
7.1 (b) For 'Other overhead voltages' and 'Other underground voltages' PWC must add additional rows for voltages other than:	We have no other voltages than those specified.

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.	
7.1 (c) PWC must specify the voltage for each 'other' voltage level.	We have no other voltages than those specified.
7.2 In relation to table 3.5.1.1 'Overhead network length of circuit at each voltage' and table 3.5.1.2 'Underground network circuit length at each voltage', circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three- phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.	Circuit length has been calculated from the GIS, which does not take into account vertical components such as sag. Each cable or conductor counts as one line regardless of the number of phases.
7.3 In relation to table 3.5.1.3 'Estimated overhead network weighted average MVA capacity by voltage class' and table 3.5.1.4 'Estimated underground network weighted average MVA capacity by voltage class', PWC must provide estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances taking	The values provided are based on the planning ratings where available, and from detailed design ratings or OEM manuals otherwise.

account of limits imposed by thermal or by voltage drop considerations as relevant.	
7.4 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.
7.5 Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, PWC may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	This does not apply to our circumstances.
7.6 (a) PWC must report total installed distribution transformer capacity in this table. The total installed distribution transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g 132 kV or 66 kV to the 22 kV or 11 kV distribution level). The capacity measure is the normal nameplate continuous capacity / rating (including forced	The distribution transformer capacity has been reported as instructed.

cooling and other factors used to improve capacity).	
7.6 (b) This measure includes cold spare capacity of distribution transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Cold spare capacity has been calculated for DPA0503 and included in DPA0501 as required.
7.6 (c) Report transformer capacity owned by PWC; give nameplate continuous rating including forced cooling.	The transformer capacity has been reported as instructed.
7.6 (d) Report the transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage.	This figure has been estimated as described above.
7.6 (e) If the transformer capacity owned by customers connected at high voltage is not available, report summation of individual maximum demands of high voltage customers whenever they occur (i.e. the summation of single annual maximum demand for each customer) as a proxy for delivery capacity within the high voltage customers.	HV customer transformer capacity is not available. In order to estimate transformer capacity and HV customer opex for template 3.2, we have estimated the HV customer transformer quantities and capacities as described above.
7.6 (f) When completing the templates for regulatory years subsequent to the 2013 regulatory year, if PWC can provide actual information for distribution transformer capacity owned by high voltage customers it must do so; otherwise PWC must provide estimated information.	Estimated information has been provided as described above.

7.6 (g) Report the total capacity of spare transformers owned by PWC but not currently in use.	Spare capacity has been reported as instructed.
7.7 Economic benchmarking workbook, regulatory template 3.5, table 3.5.2.2 Zone Substation transformer capacity: (a) Report transformer capacity used for intermediate level transformation capacity in either one or two steps. For example, high voltages such as 132 kV, 66 kV or 33kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6kV.	Transformer capacity has been reported as instructed.
7.7(b) These measures must be the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included) and include both energised transformers and cold spare capacity. Assigned rating must be, if available the rating determined from results of temperature rise calculations from testing. Otherwise report the nameplate rating. For those zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders should be reported instead of transformer capacity.	Transformer ratings have been based on maximum nameplate rating.
7.7(c) "Total installed capacity for first step transformation where there are two steps to reach distribution voltage" (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or 11 kV where there will be a second step transformation before reaching the distribution voltage. This variable is only relevant where PWC has more	Template DPA0601 has been completed with transformer capacity reported as instructed and considers the first transformation step at sites where there are two steps to reach distribution voltage. 132 kV is the reference voltage where the transformation commences in Darwin Katherine System. 66kV is the reference voltage

than one step of transformation, if this is not the case PWC must enter '0' for this variable.	where the transformation commences in Alice Springs System. 11kV is the reference voltage where the transformation commences in Tennant Creek System.
7.7 (d) For "Total installed capacity for second step transformation where there are two steps to reach distribution voltage" (DPA0602) report total installed capacity where a second step transformation is applied before reaching the distribution voltage. For example 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within PWC's system. This variable is only relevant where PWC has more than one step of transformation, if this is not the case PWC must enter '0' for this variable.	Template DPA0602 has been completed with transformer capacity reported as instructed and considers the second transformation step at sites where there are two steps to reach distribution voltage. Palmerston Zone Substation transformer (11/22 kV) and Pine Creek Zone Substation transformer (22/11 kV) are included into DPA0602 category even though they are third step transformation to reach distribution voltage, as there is no category available for third step transformation in AER tables.
7.7 (e) For "Total zone substation transformer capacity where there is only a single transformation to reach distribution voltage" (DPA0603) report total 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 as stated in 7.7 (c) and 7.7 (d) sections.
7.7 (f) For 'Total zone substation transformer capacity' (DPA0604) report the overall total zone substation capacity regardless of whether one or	Total zone substation capacity has been reported as the sum of all zone substation

two steps are used to reach the distribution voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.	transformers reported in DPA0601, DPA0602, DPA0603 and DPA0605.
7.7 (g) For 'Cold spare capacity of zone substation transformers included in DPA0604' (DPA0605), report total cold spare capacity included in total zone substation transformer capacity.	Spare capacity has been reported as instructed.

Table 3.5.1 - NETWORK CAPACITIES 2

Table 3.5.2 - TRANSFORMER CAPACITIES 2

Source of Data

The data has been sourced as follows

- Cable and Conductor Ratings - We have used the data warehouse values (based on the Sincal Power System software).
- Asset Age Profile - We have used the same sources as the Category Analysis RIN (template 5.2)
- HV Customer Installed Capacity - We have used HV customers installed capacity and estimated opex
- Cold Spare Capacity - Extracted from Maximo
- Zone substation transformer capacities - Extracted from Maximo

Estimated or actual information

Information in template 3.5.1.3 and 3.5.1.4 is estimated as defined by the AER's RIN. There is insufficient detail in our asset management system (Maximo) on cable assets to determine the precise cable ratings in all cases. As such, some assumptions were made to determine the most likely cable ratings. Alternative assumptions may have resulted in materially different outcomes.

The Capacity owned by HV Customers information in template 3.5.2 is estimated as defined by the AER's RIN. We do not record the capacity of customer-owned distribution transformers. Therefore, these have been estimated using best endeavours.

Methodology and assumptions

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 by dividing the sum of the MVA.meter values by the sum of the conductor lengths for that voltage level.

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. 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 an "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 as above.

Template 3.5.2 - Transformer Capacities - Distribution Transformer Total Installed Capacity

The distribution capacity owned by HV customers is not recorded in our systems and had to be estimated. It was calculated by first extracting a list of HV customers from the Retail Management System. The transformer capacity of each customer was estimated by dividing their peak load by the average utilisation. The sum of the resulting installed capacities was used to populate template 3.5.2.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
7.1 (a) PWC must report against the capacity variables for its whole network. In this context the network includes overhead power lines and towers, underground cables and pilot cables that	The following have been excluded from the volumes, in accordance with the instructions: • Services

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.	• Protection, communications and control cables • Streetlight cables and conductors Cables and conductors in unregulated areas
7.1 (b) For 'Other overhead voltages' and 'Other underground voltages' PWC must add additional rows for voltages other than: 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.
7.1 (c) PWC must specify the voltage for each 'other' voltage level.	We have no other voltages than those specified.
7.2 In relation to table 3.5.1.1 'Overhead network length of circuit at each voltage' and table 3.5.1.2 'Underground network circuit length at each voltage', circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders	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.

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.	
7.3 In relation to table 3.5.1.3 'Estimated overhead network weighted average MVA capacity by voltage class' and table 3.5.1.4 'Estimated underground network weighted average MVA capacity by voltage class', PWC must provide estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant.	The values provided are based on the planning ratings where available, and from detailed design ratings or OEM manuals otherwise.
7.4 This information will be used to calculate an overall MVA x km 'carrying capacity' for each voltage 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.
7.5 Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, PWC may split the circuit capacity by the ratio of the network that is overhead and	This does not apply to our circumstances.

underground to form estimates of the overhead capacity and underground capacity components.	
7.6 (a) PWC must report total installed distribution transformer capacity in this table. The total installed distribution transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g 132 kV or 66 kV to the 22 kV or 11 kV distribution level). The 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.
7.6 (b) This measure includes cold spare capacity of distribution transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Cold spare capacity has been calculated for DPA0503 and included in DPA0501 as required.
7.6 (c) Report transformer capacity owned by PWC; give nameplate continuous rating including forced cooling.	The transformer capacity has been reported as instructed.
7.6 (d) Report the transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage.	This figure has been estimated as described above.
7.6 (e) If the transformer capacity owned by customers connected at high voltage is not available, report summation of individual	HV customer transformer capacity is not available. In order to estimate transformer capacity and HV customer opex for template

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.	3.2, we have estimated the HV customer transformer quantities and capacities as described above.
7.6 (f) When completing the templates for regulatory years subsequent to the 2013 regulatory year, if PWC can provide actual information for distribution transformer capacity owned by high voltage customers it must do so; otherwise PWC must provide estimated information.	Estimated information has been provided as described above.
7.6 (g) Report the total capacity of spare transformers owned by PWC but not currently in use.	Spare capacity has been reported as instructed.
7.7 Economic benchmarking workbook, regulatory template 3.5, table 3.5.2.2 Zone Substation transformer capacity: (a) Report transformer capacity used for intermediate level transformation capacity in either one or two steps. For example, high voltages such as 132 kV, 66 kV or 33kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6kV.	Transformer capacity has been reported as instructed.
7.7(b) These measures must be the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included) and include both energised transformers and cold spare capacity. Assigned rating must be, if available the rating determined from results of temperature rise calculations	Transformer ratings have been based on maximum nameplate rating.

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.	
7.7(c) "Total installed capacity for first step transformation where there are two steps to reach distribution voltage" (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or 11 kV where there will be a second step transformation before reaching the distribution voltage. This variable is only relevant where PWC has more than one step of transformation, if this is not the case PWC must enter '0' for this variable.	Template DPA0601 has been completed with transformer capacity reported as instructed and considers the first transformation step at sites where there are two steps to reach distribution voltage. 132 kV is the reference voltage where the transformation commences in Darwin Katherine System. 66kV is the reference voltage where the transformation commences in Alice Springs System. 11kV is the reference voltage where the transformation commences in Tennant Creek System.
7.7 (d) For "Total installed capacity for second step transformation where there are two steps to reach distribution voltage" (DPA0602) report total installed capacity where a second step transformation is applied before reaching the distribution voltage. For example 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within PWC's system. This variable is only relevant where PWC has more than one step of transformation, if this is not the case PWC must enter '0' for this variable.	Template DPA0602 has been completed with transformer capacity reported as instructed and considers the second transformation step at sites where there are two steps to reach distribution voltage. Palmerston Zone Substation transformer (11/22 kV) and Pine Creek Zone Substation transformer (22/11 kV) are included into DPA0602 category even though they are third step transformation to reach distribution voltage, as there is no category available for third step transformation in AER tables.
7.7 (e) For "Total zone substation transformer capacity where there is only a single transformation to reach distribution voltage"	Transformer capacity has been reported as instructed for single step transformation sites as stated in 7.7 (c) and 7.7 (d) sections.

(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.	
7.7 (f) For 'Total zone substation transformer capacity' (DPA0604) report the overall total zone substation capacity regardless of whether one or two steps are used to reach the distribution voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.	Total zone substation capacity has been reported as the sum of all zone substation transformers reported in DPA0601, DPA0602, DPA0603 and DPA0605.
7.7 (g) For 'Cold spare capacity of zone substation transformers included in DPA0604' (DPA0605), report total cold spare capacity included in total zone substation transformer capacity.	Spare capacity has been reported as instructed.

Template - 3.6 Quality of Service

Table 3.6.1 - RELIABILITY

Source of Data

The data sources used in this template are Maximo, Geographical Information System (GIS), Retail Management System (RMS).

Outage data was sourced from the Asset Management System (Maximo): MX1069 ESAA Benchmark and Performance Report

Total Customer data from RMS "Count of Electricity Installations" Report Outage Data Calculations in 2019-2020 AER RINs - Reliability.XLSX

Feeder Customer numbers from GIS. For feeders and distribution substations, the customer count from GIS ESRI is loaded into Maximo about four times in a year.

Spreadsheet and calculations information contained in the RIN Plan.

Estimated or actual information

The template includes both actual and estimated information

- Unplanned outages are being reviewed on a monthly basis and this constitutes actual data.
- Planned interruptions are not reviewed and the data on planned outages is of poorer quality. An alternative method may yield a materially different outcome. Hence all-in-all the data provided in this template is considered to be estimated.

Methodology and assumptions

Outage Data

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

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

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

Number of Customers Affected by the Interruption

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

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

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

Major Event Day

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

- When calculating the MEDs for 2019-20, 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
- The Major Event Day Thresholds (TMED) were then identified for each of the three systems
- Any daily SAIDI value that exceeded the MED thresholds in d) was considered to be an MED and used in the AER submissions.
- There were no MEDs in 2019-20

Confidential Information

There is no confidential information in this template

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
8.1(a) Reliability data must be reported in accordance with the definitions provided in the AER's STPIS unless otherwise specified.	The information provided by PWC is consistent with the requirements and associated definitions.
8.1(b) For the purposes of calculating reliability, an interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premise. The customer	Customer interruption data that is used to address the intent of this requirements is recorded manually by System control personnel there are some data quality related issues when recording the events having a duration that is less than one minute. There available infrastructure is also not able to assist in

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.	recording events that are less than one minute in duration. Hence, in order to improve on the quality of data provided in the AER submissions, PWC has interpreted sustained outages as those having a duration of at least one minutes.
8.1 (c) An unplanned interruptions is an interruption due to an unplanned event. An unplanned event is an event that causes an interruption where the customer has not been given the required notice for the interruption or where the customer has not requested the outage.	PWC defined unplanned outages as any outage where the customer was not given at least 2 days' notice before the interruption
8.1(d) Excluded outages are defined in Appendix F.	PWC excluded interruptions described in Clause 3.3 (a) and (b) of the STPIS
8.2 (a) Reliability information in tables 3.6.1.1 and 3.6.1.2 is only to be reported for unplanned interruptions. Unplanned interruptions are as defined in the STPIS.	The outage data recorded by PWC is consistent with this AER requirement
8.2 (b) Whole of network SAIDI and SAIFI is the system wide SAIDI and SAIFI. We do not require SAIDI and SAIFI for individual feeder categories within PWC's network.	This is the sum of SAIDI/SAIFI values associated with all unplanned events with planned events, faults internal to customer premises, and cancelled events being excluded. This is calculated using the customer minutes lost and the total customer base in the regulated areas of NT

8.3(a) and 8.4(a) Report SAIDI and SAIFI in accordance with the definitions provided in Appendix F.	The outage data recorded by PWC is consistent with this AER requirement
8.4(b) The MED threshold must be calculated for the 2017 regulatory year in accordance with the requirements in the STPIS. The MED threshold calculated for 2016 must then be applied as the MED threshold for regulatory years prior to 2016 for the purpose of calculating SAIDI and SAIFI exclusive of MEDs as per the STPIS.	The MED calculations performed are in line with this AER requirement

Table 3.6.2 - ENERGY NOT SUPPLIED

Source of Data

The data sources used in this template are Maximo, Geographical Information System (GIS), SCADA.

The outage data was sourced from the Maximo. The number of customers affected by the interruption and customers served by a feeder were both sourced from the GIS/ESRI.

Outage data was sourced from the Asset Management System (Maximo): MX1069 ESAA Benchmark and Performance Report

Total Customer data from RMS "Count of Electricity Installations" Report Outage Data Calculations in 2019-2020 AER RINs - Reliability.XLSX

Feeder Customer numbers from GIS

Estimated or actual information

The template includes both actual and estimated information

- Unplanned outages are being reviewed on a monthly basis and this constitutes actual data.
- Planned interruptions are not reviewed and the data on planned outages is of poorer quality. An alternative method may yield a materially different outcome. Hence all-in-all the data provided in this template is considered to be estimated.

Methodology and assumptions

System operators record outages manually into Maximo in real time. In order to populate the RIN, the Maximo data was processed by with additional data on customers served by each feeder being obtained from the GIS and the feeder demand from SCADA.

SCADA can record feeder demand every 30 minutes. The 30 seconds SCADA data was collated for the 2019-20 financial year and the average feeder demand was calculated for each month in 2019-20. This monthly average demand for each feeder was then used as one of the inputs into the energy not supplied calculation. Using the duration of an outage, the customers affected by the outage together with the average feeder demand, the energy not supplied due to each outage was calculated. All the relevant events were added to obtain the values required in the RIN.

It should be noted that for 2019-20 financial year, the same method used to calculate the energy not served in 2018-19 and 2017-18 was used.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

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

divided by the number of customers on the feeder.	
8.5 (c) Energy not supplied should be reported exclusive of the effect of excluded outages as defined in Appendix F.	Energy not supplied was calculated after excluding all the allowed exclusions in line with Appendix F, which is consistent with this AER requirement

Table 3.6.3 - SYSTEM LOSSES

Source of Data

The data to complete RIN 3.6.3 is sourced from RIN submission 3.4.1 - Energy Delivery. The data in that RIN submission is sourced from RMS via BI reporting, MV90 reports provided by Power Services Metering, GIS asset data (for unmetered asses i.e. streetlights, CCTV, NBN) quarterly reports provided by Power Services, Traffic light data provided by Department of Infrastructure, Planning and Logistics and Generation production data provided by the Market Operator Settlement System.

Estimated or actual information

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

Methodology and assumptions

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

- System Losses = Energy Lost / Total Energy Received

Where Energy Lost = Electricity Imported - Electricity Delivered

Electricity Imported = Total Energy Received

Electricity Imported = "Energy received from TNSP and other DNSPs not included in the above categories" (DOPED0304) plus Variable "Energy received from embedded generation not included in above categories from non-residential (DOPED0404) and residential (DOPED0408) embedded generation".

Electricity Delivered = "Total energy delivered" (DOPED01)

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

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
8.5(a) Energy not supplied should be reported exclusive of the effect of excluded outage as defined in Appendix F	We have complied with this requirement.
8.6(a) PWC mush report distribution losses calculated as per Equation 2: System losses = (Electricity Imported - Electricity Delivered) / (Electricity Imported) x 100	We have used this equation

Table 3.6.4 - CAPACITY UTILISATION

Source of Data

Overall utilisation was sourced from the transformer capacities in Economic Benchmarking RIN 3.5, and Maximum Non-Coincident Demand sourced from the planning team.

Estimated or actual information

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

Methodology and assumptions

The capacity utilisation values were calculated based on the summation of non-coincident maximum demands at Subtransmission Substations and Zone Substations divided by the total transformer capacities in service.

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

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

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.	

Template - 3.7 Operating Environment

Table 3.7.1 - DENSITY FACTORS

Source of Data

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

Estimated or actual information

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

Methodology and assumptions

The density factors were calculated using existing values from the RINs as follows:

Customer Density

This has been calculated as the number of customers divided by the route line length.

Customer Density = DOPCN02/DOEF0301

Energy Density

This has been calculated as the total energy delivered divided by the number of customers

Energy Density = (DOPED01 x 1000) / DOPCN02

Demand Density

This has been calculated as the annual maximum demand divided by the number of customers

Demand Density = (DOPSD0201 x 1000) / DOPCN02

Confidential Information

There is no confidential information in this template.

Consistency with RIN requirements

The RIN did not contain any specific instructions for the calculation of density factors in template 3.7.1.

Table 3.7.2 - TERRAIN FACTORS

Source of Data

Data is sourced from the enterprise Geographic Information System (GIS) and enriched with data provided by the Vegetation Management Providers (VMP). This data is analysed to produce the required variables.

Estimated or actual information

Standard Vehicle Access

Standard vehicle access is not calculated in business systems or historically reported. Its basis is a calculated route length for 2019-20 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.

Total Number of Spans, Rural Proportion, Tropical Proportion and Bushfire Risk

These variables are based on GIS asset data and are considered actual information.

Average Maintenance Span Cycle, Span Counts, Trees and Defects per Span

These variables rely on data provided by the vegetation management provider and analysed outside of business systems. They are therefore considered Estimated.

Methodology and assumptions

Standard Vehicle Access

The calculation is based on a GIS analysis task. 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. Analysis performed using SQL database scripting tool Safe Software FME.

Maintenance Span counts are calculated in 2.7 Vegetation Management. These figures are based on inspection data collected by PWC's vegetation management provider data, and enriched with region and feeder categories using GIS operations. Total Number of Spans is a complete count of all Spans in the GIS, this includes all regions and both regulated and non-regulated areas of the network.

Our three isolated networks are characterised by terrain that is difficult to access when outside of urban areas. The Darwin-Katherine network experiences substantial wet season rain between October and May which makes any travel off-road very difficult and often impossible with 2WD vehicles until June, and sometimes later depending on the timing of the wet season. The southern networks of Tennant Creek and Alice Springs are dryer, however off-road access is generally also restricted to 4WD only due to the soil being very soft and sandy and the large washouts which are created when rain does occur. The southern regions are also heavily grassed which makes it difficult to identify washouts, and vehicle damage and hang-ups are common based on anecdotal evidence from field staff. No permanent access tracks are maintained by us due to the costs associated with reinstatement after each wet season in the northern region and regular rainfall damage in the southern region. Based on the above characteristics, and no actual information being available, we have assumed that a 4WD vehicle is required to access a circuit greater than 15 metres from a standard roadway in areas outside of Administrative Town Boundaries defined by the Northern Territory Department of Lands and Planning.

Rural Proportion

Rural proportion is based on the GIS scripts described in the Basis of Preparation for table 2.7.2. Route length is an output of the script and is classified by feeder category to produce the proportion of network length in the rural categories.

Span Counts

Total, Urban and Rural Maintenance spans are calculated using the same data set and methodologies described in the Basis of Preparation for table 2.7.2. The data output of this process is aggregated to a higher level for table 3.7.2. The total number of spans is a count of spans in the GIS system for the regulated network.

Average Span Cycle

The average span cycle for urban and rural spans is calculated using an average span cycle by feeder category. The planned frequency of span maintenance is based on individual vegetation management zones.

Average Trees and Defects per Span

Average trees for Rural and Urban spans are calculated using the same methodology described in the BOP for table 2.7.2. The data is aggregated to a higher level for table 3.7.2. Average defects per span differ slightly from Average trees per span in that Hazard Tree removals are included as a defect. Hazard Tree data is provided by the Vegetation management Provider and prepared as part of the preparation of table 2.7.3.

Tropical Proportion

The tropical proportion of the network is calculated based on whether identified maintenance spans in table 2.7.2 are located north of the Tropic of Capricorn. The isolated nature of Power and Water's network means that all maintenance spans in Darwin and Katherine Regions are considered tropical.

Bushfire Risk

Power and Water have no designated Bushfire Management Zones at the time of reporting. The value for this variable is therefore 0.

Confidential Information

No confidential information has been provided in this template.

Consistency with RIN requirements

Appendix E Requirements	Consistency with the Requirements
9.1(a) Complete table 3.7.2 in accordance with the definitions provided in Appendix F	We have applied the definition in Appendix F to complete table 3.7.2.
(b) IF PWC has actual information, PWC must report all years of available data. If PWC does not have actual information on these variables, then it must estimate data for the most recent regulatory year -	We do not have actual data, so have only reported for the relevant regulatory year (ie: 2018-19).

Table 3.7.3 - SERVICE AREA FACTORS

Source of Data

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

- Total Route Length and Standard Vehicle Access Data Sheet - 2017-18 Determining Standard Vehicle Access for table 3.7.2 and 3.7.3 EB RIN
- Vegetation Zone Route Length and Total Number of Spans - 2017-18 Vegetation Management for EB 3.7.2, 3.7.1 and CA RIN 2.7.1_Audit_V2 and 2017-18 Span Data for table 3.7.2 and 3.7.3 EB RIN
- Asset Age Profile - Asset Data and Charts for Asset Management Plans Route length SQL script output 20180830 - Overhead Route Lengths with Feeder

Estimated or actual information

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

Methodology and assumptions

Our method to calculate route line length was as follows:

- the length of service lines only counted to 2 metres within any property boundary;
- the length of a span that shares multiple voltage levels is only to be counted once; and
- the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

To calculate route line length for the 2019-20 year, an SQL data base script has been developed using SQL database scripting tool Safe Software FME to perform the following analysis of GIS data:

- Calculate the length of service lines up to 2 metres within any property boundary,
- Calculate the length of the network as per the length of a span that shares multiple voltage levels is only to be counted once and the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

The route length SQL script output was an excel spreadsheet with a route length and service line lengths for each feeder. This data was then used to calculate the route line length for each vegetation management zone in CA RIN Template 2.7 and then added together to calculate the total route length of the regulated network for 2019-20.

Confidential Information

There is no confidential information in this table.

Consistency with RIN requirements

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