Basis of Preparation

Economic Benchmarking RIN 2020-21

November 2021

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Purpose

This document is Essential Energy's Basis of Preparation in relation to the audited Economic Benchmarking RIN data as required by part 1.1 (d) of Schedule 1 of the AER Regulatory Information Notice.

It explains the basis upon which information was prepared for all information in the Economic Benchmarking RIN template. As required by the AER, this Basis of Preparation is a separate document that has been submitted with the completed regulatory templates.

AER's Instructions

The AER requires the Basis of Preparation to follow a logical structure that enables auditors, assurance practitioners and the AER to clearly understand how Essential Energy has complied with the requirements of the Notice. It must be a separate document (or documents) that Essential Energy submits with its completed information templates.

The AER has set out what must be in the Basis of Preparation. This is set out in Table 1 below.

Table 1: Requirements of the Basis of Preparation

Number	Requirement
1	Demonstrate how the information provided is consistent with the requirements of the Notice.
2	Explain the source from which Essential Energy obtained the information provided.
3	Explain the methodology Essential Energy used to provide the required information, including any assumptions Essential Energy made.
4	In circumstances where Essential Energy cannot provide input for a variable using actual information, and therefore must use an estimate, explain: > Why an estimate was required, including why it was not possible for Essential Energy to use actual information; > The basis for the estimate, including the approach used, assumptions made and reasons why the estimate is Essential Energy's best estimate, given the information sought in the Notice.
5	For variables that contain financial information (actual or estimated) the relevant Basis of Preparation must explain if accounting policies adopted by Essential Energy have materially changed during any of the Regulatory Years covered by the Notice: > the nature of the change; and > the impact of the change on the information provided in response to the Notice. Essential Energy may provide additional detail beyond the minimum requirements if Essential Energy considers it may assist a user to gain an understanding of the information presented in the Templates. In relation to providing an audit opinion or making an attestation report on the Templates presented by Essential Energy, an auditor or assurance practitioner shall provide an opinion or attest by reference to Essential Energy's Basis of Preparation.

When carrying out an audit or review, an auditor or assurance practitioner shall have reference to Essential Energy's Basis of Preparation.

Structure of this Document

This document is structured as follows:

- Essential Energy addresses the issue of data reliability and use of estimates in completing the Economic benchmarking RIN..
- The response to worksheets 3.1 to 3.7, is set out in accordance with the AER's instructions. It is noted that Worksheet 1.0 requires no input material.

General Approach

Data Quality Issues

In previous consultations on the RIN, Essential Energy raised significant concerns with providing some of the data in the form required by the AER. Essential Energy has actual data with which to complete many of the information tables in this RIN, but where such data is not available, information templates will be completed with estimated data.

Whilst the business continues moving toward more accurate reporting for the RINs and is currently looking to update ERP and Asset Management systems which will contribute to further improvement, in the meantime Essential Energy continues to stress concern in relation to the detailed templates submitted and the reliance on some of this information for benchmarking and decision-making purposes.

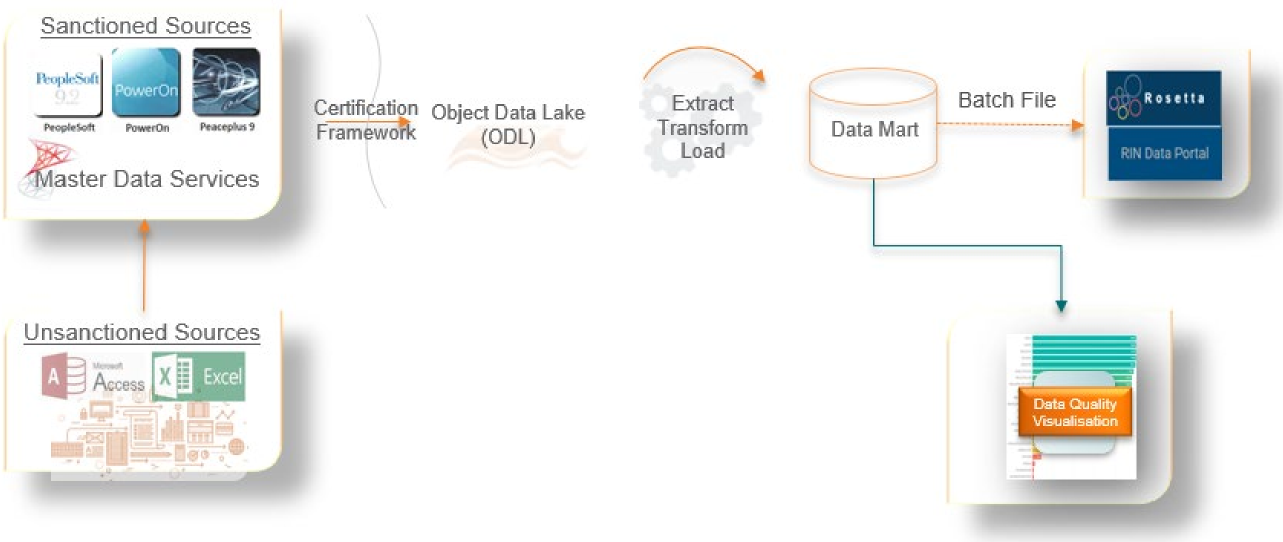
Systems Used to Provide Data

Essential Energy's RIN Optimisation project aims to automate the population of some RIN tables. During this project, the required source data was classified as one of two types, sanctioned and unsanctioned.

Sanctioned data is data available from established databases and source systems such as PeopleSoft, PEACE, WASP, etc. Unsanctioned data is sourced from Excel, Access DB, Text files, etc. Wherever a source was identified as unsanctioned, it was tagged for loading to enable certification of the data load.

This scalable automation framework will feed into a continuous improvement process seeking to build confidence in the quality of the data and minimise the risk of submitting incorrect information.

Where data has been sourced directly from Essential Energy's financial and other information systems, this system has been identified. Similarly, where estimated data is based on data sourced from Essential Energy's systems, those systems are identified.



The transformation logic and business rules used to populate the RINs were captured and documented by the project team. The logic and the rules applied was reviewed and signed-off on by the various data owners across the business. All data is certified during loading and no uncertified raw data inputs are used.

Once transform logic is applied to the loaded data, the results are stored in a RIN Data Mart which also tracks history, so that any updates or amendments are tracked accordingly. There is an adjustment framework to cater for any adjustments to previously loaded data, which ensures full traceability and auditing.

Data is loaded from the RIN Data Mart into Rosetta, an independent application used by Essential Energy to populate RIN tables. Data for non-automated RIN tables is entered directly into Rosetta. Rosetta has review and approval functionality, requiring organisational managers to review and approve assigned completed RIN tables.

Once all approvals have been completed, the data is exported from Rosetta into Excel RIN templates and checked for classification into actual or estimate prior to submission to the AER.

Process Used to Determine if Information is Actual or Estimated

Where actual information is not able to be derived from Essential Energy's financial and information systems, information has been provided using the best available estimate. In circumstances where the AER has recommended an approach for estimating, that approach has been followed as far as practicable and reasons for any variations have been identified and explained.

In compliance with the AER's definitions of actual and estimated information, as listed in the Instructions and Definitions document of the RIN, if submitted information is materially dependent on information from historical records, it is more likely to be treated as actual information. Alternatively, data whose presentation is contingent on judgements and assumptions for which there are valid alternatives and which could lead to a materially different presentation is likely to be classified as estimated information.

Worksheet 3.1 – Revenue

Table 3.1.1 – Revenue grouping by chargeable quantity, and

Table 3.1.2 – Revenue grouping by Customer type or class

Compliance with Requirements of the Notice

This section contains data on the revenue allocated to the Distribution business as shown in the 2020-21 regulatory returns as per the requested groupings. The revenue includes amounts billed in FY20 and year end accruals.

Source of Information

> Total revenue amounts have been sourced from PEACE (via NRC – Cognos reporting tool) and aligns to the Statutory Accounts and table 8.1 of the Annual RIN. This also reconciles back to the internal Management Accounts.
> Revenue from Distribution Use of Service (DUoS) DREV0101 to DREV0109 is sourced from the Annual Regulatory Accounts, which reconciles back to the internal Management Accounts. The Network Revenue Cube (NRC - COGNOS) is the reporting tool used to provide the required breakdown by AER category. For the unread meters accrual, the Network Revenue accrual file provides the breakdown required to categorise the data into the AER categories. Thus, no estimation is required.
> Revenue from Metering Charges DREV0110 (Alternative Control) is sourced from the audited Annual Regulatory Accounts, which reconcile back to the internal Management Accounts.
> Revenue from Connection Services DREV0111 (Alternative Control) relates to ancillary network services revenue and is sourced from the audited Annual Regulatory Accounts, which reconcile back to the internal Management Accounts.
> Revenue from Public Lighting Charges DREV0112 (Alternative Control) is sourced from the audited Annual Regulatory Accounts, which reconcile back to the internal Management Accounts.
> Revenue from other sources DREV0113 relates to a variety of Miscellaneous and Sundry income and is sourced from data used to compile the Annual Regulatory Accounts, which reconciles back to the Management Accounts.
> Revenue from Other Customers DREV0206 relates to charges for Alternative Control (Metering, ANS and Public Lighting).

Methodology & Assumptions

Total revenue from Metering, Connection and Public Lighting charges and Other Sources is taken from the Annual Regulatory Accounts.

The EB_3.1_Revenue.xlsx file provides information included in the Network Revenue accrual. The includes 2020-21 related DUoS revenue, as well as any under/(over) accrual from 2019-20. The table below provides the mapping from the internal Management Accounts to the AER categories:

Table 3.1.1

Revenue from Energy Delivery charges where time of use is not a determinant	ENERGY	KWH	Residential Continuous, Business Continuous	ANYTIME
Revenue from On-Peak Energy Delivery charges	ENERGY	KWH	Exclude Controlled Load & Streetlight NUoS	PEAK
Revenue from Shoulder period Energy Delivery charges	ENERGY	KWH	Exclude Controlled Load & Streetlighting NUoS	SHOULDER
Revenue from Off-Peak Energy Delivery charges	ENERGY	KWH	Exclude Controlled Load & Streetlighting NUoS	OFF-PEAK

Revenue from Energy Delivery charges where time of use is not a determinant	ENERGY	KWH	Residential Continuous, Business Continuous	ANYTIME
Revenue from controlled load customer charges	ENERGY	KWH	Controlled Load 1 & 2	N/A
Revenue from unmetered supplies	ENERGY	KWH	Streetlighting NUoS	N/A
Revenue from Contracted Maximum Demand charges	CAPACITY	KVA	All	All
Revenue from Measured Maximum Demand charges	DEMAND	KVA	All	All

Table 3.1.2

RIN Mapping Table 3.1.2	Customer Segment
Revenue from residential customers	Residential Continuous
	Residential TOU
	Residential – Opt in Demand
	Controlled Load 1
	Controlled Load 2
Revenue from non-residential customers not on demand tariffs	Business Continuous
	Business – Opt in Demand
	Business TOU < 100MWh
	Business TOU > 100MWh
Revenue from non-residential low voltage demand tariff customers	Low Voltage Demand
Revenue from unmetered supplies	Streetlighting NUoS
Revenue from non-residential high voltage demand tariff customers	High Voltage Demand
	Subtransmission
	Site Specific
	Inter Distributor Transfers

Use of Estimated Information

All information for these tables was based on actual data.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data in these tables is considered to be reliable.

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

Compliance with Requirements of the Notice

Essential Energy has reported the penalties or rewards of incentive schemes in this table.

Amounts reported in Table 3.1.3 reflect the effect on revenues of incentive schemes in the year that the penalty or reward is applied.

Source of Information

Data has been sourced from the incentive scheme payments which Essential Energy has received or paid..

Methodology & Assumptions

The STPIS reflects the effect on revenue from the scheme in the year the penalty or reward is applied, i.e. any benefit or penalty resulting from the Scheme in FY18 would be applied to revenue to be recovered in FY20. However Essential Energy chose to bank the penalty/reward as allowed under the scheme and approved by the AER, meaning no STPIS was applied to revenue to be recovered for the 2019-20 year.

The AER's final decision for the 2019-24 Determination provided allowances for the CESS and DMIA incentive schemes. These allowances are inflated by CPI and reported in the Other category. The allowances and inflation adjustments are shown in the table below.

	2019-20	2020-21	2021-22	2022-23	2023-24
DMIA $18-19	919,218	929,705	931,883	928,215	901,493
CESS $18-19	13,818,469	13,818,469	13,818,469	13,818,469	13,818,469
CPI	1.78%	1.84%			
DMIA $19-20	935,618	946,816			
CESS $19-20	14,065,007	14,072,796			
RIN - Other	**15,000,625**	**15,019,612**			

CPI is calculated as Dec(t-1) over Dec(t-2) using the weighted average of all capitals as reported by Australian Bureau of Statistics and shown below, no rounding is applied.

	Mar-2018	112.6
	Jun-2018	113.0
	Sep-2018	113.5
(t-2)	**Dec-2018**	**114.1**
	Mar-2019	114.1
	Jun-2019	114.8
	Sep-2019	115.4
(t-1)	**Dec-2019**	**116.2**

Use of Estimated Information

As the data provided in this table is actual, it was not necessary to make any estimations.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided in this table is considered to be reliable.

Worksheet 3.2 – Operating expenditure

Table 3.2.1 – Opex Categories

Compliance with Requirements of the Notice

This section contains data on various opex categories within the Distribution business.

Source of Information

Data has been sourced from the Peoplesoft financial system and the Annual Regulatory Accounts.

Methodology & Assumptions

2019-20 PeopleSoft general ledger transactions were uploaded into a database. There, each transactional combination of department, account, product and project type, and its subtotal, was classified with a standard description and a label, as well as an allocation method (for allocating dollar values into RIN categories). The allocation method and subsequent allocation percentages were assigned to RIN categories as per Essential Energy's Cost Allocation Methodology (CAM).

The process for expenditure is the same as prior years. The first step in the process involves the extraction of an end of financial year trial balance which is broken down by business unit, department, account, product and project number. Data is also extracted on the last tree structure (account, department, product and project) for the year in question, and data on project types. The enriched PeopleSoft data exists in the ODL, and logic (described below) and utilising tables within MDS is applied to allocate the line items across RIN Business Units. It is then summarised and used to update Rosetta. There was no change to the data being used or mapping tables and logic (unless otherwise stated).

The data is allocated in a four-step process in order:

1. Business unit - if the business unit is not CE001, then business unit allocation is used.
2. Project - if the business unit is CE001 and there is a project, then project allocation is used.
3. Account/Department - account/department allocation is used as indicated by the allocation basis in Account_Tree.
4. Override - override allocation is used.

Manual adjustments were made to reallocate incorrect mapping or allocation of certain costs noted as incorrectly classed.

The table "Account_Tree" indicates the basis of allocation to be used for each account as shown in the "Allocation_Basis" field of the trial balance. This table is only used for data which is assigned to business unit CE001 and contains no product or project information. For each of these there is then a further table indicating the appropriate allocation to be used for each account, department, or product.

The allocation percentages and the allocation methodologies are derived from company total Direct Spend for the year.

Adjustments may be made, such as entries required to align the regulatory statements with Essential Energy's statutory accounts or incorrectly mapped project types. These adjustments are fed back into the model using the manual journal process or manually through spreadsheet and Rosetta.

Use of Estimated Information

The information has been sourced from the Finance system and is considered to be actual data.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

This data is considered to be reliable.

Table 3.2.2 – Opex consistency

Compliance with Requirements of the Notice

This section contains data on various opex variables within the Distribution business.

Source of Information

Data has been sourced from the Peoplesoft financial system and agrees to the Annual Regulatory Accounts.

Methodology & Assumptions

The data is the same as the figures in Table 3.2.1 (outlined above) and Table 8.4.1 of the Annual Reporting RIN. It has been slightly re-categorised in order to report on the variables requested in this table.

The amount reported for Opex for Network Services DOPEX0201 is the sum of the Standard Control Services categories reported in Table 3.2.1.

Opex for Connection Services DOPEX0203 relates to Ancillary Network Services operating expenditure and is sourced from Table 3.2.1 and the Annual Regulatory Accounts.

Use of Estimated Information

Balanced to amounts reported in 3.2.1 Opex Categories which is classified as actual.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data was sourced from the Annual Regulatory Accounts and is therefore considered to be reliable.

Table 3.2.4 – Opex for high voltage customers

Compliance with Requirements of the Notice

This section contains an estimate of the operating expenditure that would have been incurred by Essential Energy, had it owned the transformer assets owned by its high voltage customers.

Source of Information

The key data used to determine private HV transformer capacity has been sourced from connection agreements which include the agreed MVA transfer rate to each customer. The data has been fully reviewed since 2019 and now provides the most accurate assessment of MVA. The actual MVA of equipment installed on site may exceed the agreed MVA transfer rate as transformers are rarely run at 100%, however for the purposes of this exercise the transfer rate provides the best estimate.

Methodology & Assumptions

The opex required to operate the distribution transformers owned by our high voltage customers is largely based on the capacity of distribution transformers determined for DPA0502 (EB RIN Table 3.5.2.1). The key data used to determine private HV transformer capacity has been sourced from connection agreements which include the agreed MVA transfer rate to each customer. The following logic was used to determine the maintenance costs.

Customers with a transfer capability over 5MVA and/or a connection voltage of over 33kV were assumed to have a single zone substation to reduce voltages to distribution level, typically 11kV. All other customers were assumed to only have distribution voltage substations. Each customer was then assessed as requiring one distribution substation per 500kVA of demand or part thereof.

Whilst there is no detail of the asset types, condition or required maintenance, a simple estimate of an assumed annual maintenance cost has been developed for the quantities that were derived in the assumptions above.

- This estimate is of direct costs only and excludes overhead costs. The rationale for showing direct costs only and excluding overhead costs is that Essential Energy should only be reflecting the incremental costs to the business.
- Internal costing estimates covering Labour, Fleet, Materials and Travel costs were used to estimate the costs of sites falling under and over 5MVA.
- Maintenance and running costs for HV sites over 5 MVA are significantly higher than for those which are under 5 MVA.
- The maintenance costs include both routine and minor non-routine maintenance, however they do not cover replacement or major repair costs.
- The logic used for calculating the maintenance costs is similar to that used in previous years, with most of the variance due to accuracy of the high voltage customer data we hold, or changes in the load demand due to connection agreement changes.
- No allowance has been made for overhead or underground circuits or switchgear as there is no basis on which to determine this.

Use of Estimated Information

Essential Energy has estimated the capacity of distribution transformers owned by our high voltage customers as we do not have accurate records of the assets on these networks. We also don't have details of these assets so any estimate of the maintenance cost is therefore also estimated.

Material Accounting Policy Changes

The data has been fully reviewed since 2019 and now provides a more accurate assessment of MVA.

Reliability of Information

The data provided in this table is based on assumptions and estimates, so extreme caution should be used when using this information for benchmarking or decision-making purposes. The data used for the compilation of this expenditure is highly unreliable and it is not advised that it can be used for any purpose with any degree of certainty. It should not be used for the purposes of any benchmarking activity. Essential Energy cannot report with any level of accuracy on the private equipment owned by its high voltage customers, or the operating and maintenance costs of equipment which it does not own or manage.

Worksheet 3.2.3 – Provisions

Table 3.2.3 – Provisions

Compliance with Requirements of the Notice

This section contains data on provisions allocated to the Standard Control sector of the business as shown in the 2021 Economic Benchmarking RIN.

Source of Information

Data utilised in this return has been sourced from Peoplesoft financial system, work files used in preparation of the 2021 statutory financial statements, and work files used in the preparation of the 2021 Annual Regulatory Accounts.

Methodology & Assumptions

The sign convention applied is consistent with the Annual Regulatory Accounts where provision values are expressed as negatives, and with provision increases also expressed as negatives.

The methodology and assumptions employed for 2020-21 are similar to those applied in the previous Economic Benchmarking RIN. The Standard Control Services portion of the movement in the respective provision was calculated using the relevant CAM allocation, and a component relating to capital expenditure was calculated on labour related provisions. For 2020-21, where a 100% Standard Control Services allocation method was not applied, the direct spend allocation method was used.

A portion of the increase in employee related provisions (employee entitlements, worker's compensation, and defined benefit superannuation) has been included in capital projects through the labour overhead process. This process allocates various labour overheads (e.g. leave provision increases, superannuation expense, etc.) across operating expenditure and capital expenditure. No allowance has been made for any indirect form of capital allocation of the operating expenditure component of these provisions. Where provisions relate to corporate costs, movements have been classified as being opex in nature. In the financial statements, a portion of corporate overheads is allocated to capex projects.

The above method approximates the allocation of increases and releases in provisions between operating and capital expenditure in the financial statements. The financial statements do not separately disclose the provision movements relating to operating and capital expenditure and these movements are not separately recorded in the accounting records. Australian Accounting Standards do not require this level of disclosure. The allocation of the utilisation of provisions and adjustment of allocation of opening balances between opex and capex components does not affect profit and loss or capital expenditure in the financial statements, so the allocation of these movements is a notional allocation only.

The increase in the provision over time due to interest unwinding and the effect of any change in discount rate have been split out for employee entitlements and the defined benefit superannuation provision. The employee entitlement movement relating to discount rate changes includes some estimation.

The Other Provision category includes asset remediation provisions and miscellaneous minor provisions. In 2021 it included provisions for heritage site remediation, lease make good costs, insurance claims, remediation of master subtractive metering arrangements, and legal fees.

Use of Estimated Information

Data used to create the provision table is materially dependent on data in Essential Energy's Peoplesoft accounting records and is considered actual.

Material Accounting Policy Changes

There were no material accounting policy changes during 2021, but the accounting for labour was modified so that leave payments that had previously gone to the provision now went directly to the income statement. For provision disclosures in 2021 the amount of employee entitlement additions has been grossed up by the value of payments taken to the income statement.

Reliability of Information

This information is considered reliable.

Worksheet 3.3 – Assets (RAB)

Table 3.3.1 – Regulatory Asset Base Values,

Table 3.3.2 – Asset value roll forward,

Table 3.3.3 – Total disaggregated RAB asset values, and

Table 3.3.4 – Asset Lives

Compliance with Requirements of the Notice

The following subheadings demonstrate how the information provided is consistent with the requirements of this Notice.

Essential Energy has:

> Reported its Regulatory Asset Base (RAB) assets in line with the asset input categories for economic benchmarking.
> Excluded Metering Services from the Network Services data.
> Reported its RAB values in accordance with the standard approach in section 4.1.1 and the assets (RAB) Financial Reporting Framework in box 7 of the Economic Benchmarking RIN for DNSPs Instructions and Definitions document.
> Since 2014-15, the amended distribution roll forward model (RFM) for Standard Control Services (SCS) and applied forecast depreciation have been used. A further amended RFM was issued by the AER on 7 April 2020, to give effect to changes made to tax depreciation set out in the AER's final report on the review of the regulatory tax approach. This has been utilised from 2019-20.
> Included Substation land in the Substation categories.
> Reported capital contributions as DRAB13.This is the total of Type 1 and Type 2 capital contributions – see variation notice 8 September 2021, issued by the AER to Essential Energy. Although this refers to the Annual Reporting RIN it also is relevant for the Economic Benchmarking 3.3 RIN.
> No dual function assets.
> Reconciled the data between Tables 3.3.1 and 3.3.2.
> Reported an Easements value as this data has been previously recorded.
> Used an average of the opening and closing RAB values for each category in completing Table 3.3.3.
> Reported asset lives in accordance with the definitions provided in Chapter 9 of the Economic Benchmarking RIN for DNSPs Instructions and Definitions document.
> Calculated residual asset lives by weighting the lives of individual assets within that category.
> Whilst Substation Land is included in the RAB values for Substations, it has been assumed to have an indefinite life. As such, it has not formed part of the residual life calculations.

Glossary:

Term	Meaning
ACS	Alternative Control Services
FY	Financial year
PTRM	Post Tax Revenue model
RAB	Regulatory Asset Base
RFM	Roll Forward Model
RIN	Regulatory Information Notice

SCS	Standard Control Services

Source of Information

There are eight main sources used to obtain the information for the RAB workings:

1. The Power BI file (containing enriched data from the ODL) used to populate the Annual RIN table 8.2.4 Capex was used as source data.
2. The **Final Determination PTRM for Standard Control** – used for determining each regulatory period's opening RAB values, standard lives and carried forward residual asset lives in the SCS RFM.
3. The **Final Determination PTRM for Metering** – used for determining each regulatory period's Metering asset opening RAB values, standard lives and carried forward residual asset lives in the ACS RFM.
4. The **SCS RFM for the current regulatory period** – based on the prior period's final determination RFM and PTRM and updated for actual CPI, WACC, capex, disposals and capital contributions. Forecast depreciation has been used since FY15. This model also calculates the inflation addition and straight-line depreciation amounts.
5. The **Metering RFM for the current regulatory period** – based on the final determination PTRM for Metering and the Final Determination Meter Pricing Model, the RFM is updated for actual CPI, WACC, indirect capex, disposals and capital contributions. The model calculates the associated inflation addition and straight-line depreciation amounts.
6. The **System Assets Fixed Asset Register (FAR) as at 30 June for each year since FY13** - This contains the asset financial information by asset class as well as the depreciated cost base at that date. It has been used to determine the percentages to disaggregate RAB categories in the RFM that could not be directly apportioned. It has been assumed that the asset splits in the FAR are consistent with the asset splits in the RAB. Each year, the rates are "sense checked" to prior years' rates. Since FY13, each year's FAR derived rates are used to disaggregate the data for that year.
7. **Unit rates** – the Asset Management Team prepared this sheet to roll forward unit rates from the Reset RIN that was a part of our 2014-19 Regulatory Determination (to ensure the relevance of asset weightings when determining asset ages). For the 2019-24 period, the unit rates from the AER's Repex Model have been used as the main source of unit rates.
8. **Table 5.2.1 Asset Age Profile** - from the Category Analysis RIN. This has been used to determine the average asset age by asset category.

Methodology & Assumptions

The main assumptions are:

- FAR splits as at 30 June each year are representative of the RAB asset splits for assets requiring disaggregation. The rates are compared to prior years to ensure they are materially consistent.
- Other long-life assets comprise: Furniture, Fittings, Plant & Equipment, Buildings, Land (non-system), Other non-system assets and Equity raising costs.
- Other short life assets comprise: Communications, IT systems, Motor Vehicles and Capitalised Leases.
- WIP, Emergency spares, RAB adjustment and Deferred depreciation asset categories are no longer relevant to Essential Energy, in line with the 2014-19 Final Determination.
- Since 2008-09, the RAB sheet has included adjustments for the non-cash proportion of capitalised workers' compensation and employee entitlement provisions against additions, in line with the 2014-19 Final Determination.
- The calculated regulatory period end adjustments to capex, i.e., the difference between actual and forecast net capex and the return on difference of net capex are included in the additions amount for the final year of each regulatory period. This ensures the closing RAB reported in the RAB sheet accurately reflects the actual RAB value at the end of each regulatory period.
- Actual additions reported in the RAB differ from those reported in the Annual Financial Statements as a result of the inclusion of any non-cash provision adjustments related to workers' compensation and employee entitlements as well as the half-year of WACC inflation applied to disposals and additions in the RFM.
- Capex in the Metering RFM since 2014-15 relates to indirect capital expenditure. An adjustment was made in 2018-19 to update the Metering RFM for indirect capital expenditure in 2017-18 of $1.8M. This was not previously included in the 2017-18 EB 3.3 RIN. This is an immaterial amount but has been included in the 2018-

19 EB RIN for completeness. The opening RAB values are linked to the prior year's closing balance with immaterial differences for rounding and minor formula corrections.

Scope of services

As specified in section 9 of the AER Economic Benchmarking Instructions and Definitions for Essential Energy, Fee Based and Quoted Services costs are already excluded from Essential Energy's RAB values.

Alternative Control numbers

Alternative Control RAB numbers reconcile to the Metering RFM and apply to Metering Types 5 and 6 only.

There is no RAB for public lighting as these costs are built up on an annuity basis.

Network Services & Standard Control numbers

Network Services and Standard Control are the same and exclude Type 5 and 6 meters which are classified as Alternative Control. Since 2014-15, the Network Services and Standard Control Services numbers have matched and are sourced from (and reconciled to) the SCS RFM. Essential Energy still have some meters which are used by the network (not customers) and these are reported under both Network Services and Standard Control.

Allocating the RFM asset category data to the RAB worksheet asset categories

Some RAB financial information can be directly allocated to a group of RAB assets. Other information requires disaggregation. These classes are summarised in the two tables below.

Table 3.3.2 - RAB categories that have been directly apportioned

OLD RAB category	New RAB category	Assumptions
Customer Metering and Load Control	Meters	Assumed load control is part of Meters category
Easements	Easements	
Communications	Other assets with short lives	
Motor vehicles	Other assets with short lives	Assumed to be a short life asset as standard life is <10 years*
IT systems	Other assets with short lives	
Furniture, fittings, plant & equipment	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years*
Land	Other assets with long lives	Land is assumed to not depreciate
Buildings	Other assets with long lives	
Other non-system assets	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years*
Equity raising costs		Assumed to be a long life asset as standard life is >10 years*

* In line with section 9 of the AER Economic Benchmarking Instructions and Definitions for Essential Energy.

Table 3.3.3 - RAB categories that required disaggregation

Old RAB categories	New AER categories
1. Low voltage lines and cables 2. Distribution lines and cables 3. Subtransmission lines and cables	1. Overhead network assets <33kV 2. Underground network assets <33kV 3. Overhead network assets 33kV and above 4. Underground network assets 33kV and above

5. Substations 6. Transformers 7. Land related to Substations	8. Distribution substations including transformers 9. Zone substations including transformers

The data for directly apportioned RAB categories could be taken directly from the relevant RFMs. The disaggregated RAB categories, however, require disaggregation. This has taken place in a consistent manner with prior year approaches and is described below.

Disaggregating RAB values

> For opening RAB value, inflation, depreciation and disposals

To disaggregate the RAB categories noted in Table 2 above, a breakdown of the system assets Fixed Asset Register by asset class as at 30 June was obtained. The (more detailed) existing asset classes on this register were then mapped to the new AER RAB categories. The results of this mapping were then summarised in a pivot table to give the depreciated replacement cost by new AER RAB category. The proportions of this analysis were then applied to the inflation, depreciation and disposals data in the SCS RFM.

> For additions

Additions data for system assets was sourced from the Global Capex working papers. Since FY2019 it has been possible to map the capex in the system to the required RAB disaggregated categories. A PowerBI Report is run which shows the capex by required category.

Table 3.3.1 Regulatory Asset Base Values

This table is a summation of the asset data contained in Table 3.3.2 Asset Value Roll Forward. Formulas have been entered accordingly. The data in this table reconciles to the total of the relevant RFMs, i.e. since 2014-15, the values for Network Services and Standard Control Services equal the SCS RFM and the value for Alternative Control Services equals the Metering RFM.

Table 3.3.2 Asset Value Roll Forward

As described above, once the proportions for asset categories that required disaggregation had taken place, the data from the relevant RFM was linked into the relevant sections of Table 3.3.2. A brief explanation for each line follows:

OPENING RAB VALUE

> The opening RAB values are linked to the prior year's closing balance with immaterial differences for rounding and minor formula corrections – except for 2014-15 where the opening balances for SCS equal the 2013-14 Network Services closing balances and the amounts were moved to reflect the opening RAB value for Alternative Control Services RAB for Meters Type 5 and 6. An adjustment was made in 2018-19 to update the Metering RFM for indirect capital expenditure in 2017-18 of $1.8M. This was not previously included in the 2017-18 EB 3.3 RIN. This is an immaterial amount but has been included in the 2018-19 EB RIN for completeness.

INFLATION ADDITIONS

> The inflation additions were taken directly from the relevant RFM for assets that were directly apportioned or were multiplied by the relevant percentage for assets that required disaggregation.

STRAIGHT LINE DEPRECIATION

> The straight line values were taken directly from the relevant RFM for assets that were directly apportioned or were multiplied by the relevant percentage for assets that required disaggregation. Since 2014-15, the amounts are based on forecast depreciation from the relevant period's final determination PTRM.

REGULATORY DEPRECIATION

> The sum of the inflation addition and the straight line depreciation rows equals the regulatory depreciation amount for each asset category.

ADDITIONS

- These numbers are net of customer contributions and were either taken directly from the Annual Reporting RIN (non-system assets) or from the Regulatory capex work files aligned to the new RAB categories.
- These numbers are net of customer contributions and are taken directly from the Global Capex workpapers aligned to the new RAB categories.
- For each category the resulting dollars have been inflated by the half-year WACC rate to align with the RFM model.
- The additions in the final year of each regulatory period include the adjustment amounts for that year to give a true picture of the closing RAB for that year (and the opening RAB for the next regulatory period).

DISPOSALS

- Disposals were taken directly from the input sheet in the RFM for assets that were directly apportioned or were multiplied by the relevant percentage for assets that required disaggregation.
- All disposal values have been uplifted by the half-year vanilla WACC rate in line with the RFM.

CLOSING RAB VALUE

- The closing RAB values were calculated using the inputs above and cross-checked to the relevant RFM(s) results to ensure accuracy.

CAPITAL CONTRIBUTIONS

The RAB additions noted are exclusive of capital contributions. For the purpose of updating the RFM, only Type 1 Capital Contributions have been entered in the RFM Input sheet from 2020/21. This aligns with the advice from the AER in their letter to Essential Energy, dated 8 September 2021 which states “A new requirement to disaggregate capital contributions reflecting the Federal Court ruling (October 2020) that the value of assets that are ‘gifted’ to distribution businesses (in effect constituting a capital contribution) are not taxable income”. The variation notice accompanying this letter disaggregates Capital Contributions into Type 1 (Cash Contributions) and Type 2 (any form of capital contributions received by a DNSP (including gifted or cash contributions) that do not meet the definition of Type 1)

For the purposes of the EB RIN 3.3.3, DRAB13 Capital Contributions have been reported as the total of Type 1 and Type 2 Capital Contributions, taken directly from the Annual Reporting RIN.

There have been no Alternative Control Services capital contributions. All capital contributions relate to Standard Control Services (and Network Services) RIN tables.

Table 3.3.3 Total Disaggregated RAB Asset Values

This table is a direct feed of the average opening and closing RAB values by asset category derived in Table 3.3.2. Formulas have been entered accordingly.

Table 3.3.4.1 Asset Lives – Estimated Service Life of New Assets

- The estimated service lives of new assets are based on the standard asset lives from the relevant PTRM model.
- The Estimated Service Life of New Assets for Standard Control Services and Network Services assets remain unchanged from prior year workings for all asset classes other than “Other assets with long lives” and “Other assets with short lives”. This is considered reasonable on the basis that the assets comprising each category would remain in fairly constant proportion over time.
- The estimated service life of new “Other assets with long lives” and “Other assets with short lives” are based on a weighted average calculation of the standard lives of the assets comprising the closing RAB balance.
- The standard asset lives are comparable to the asset lives within the PTRM models.

Table 3.3.4.2 Asset Lives – Estimated Residual Service Life

For the disaggregated asset categories:

- The asset data for the five categories of Poles, Overhead Conductors, Underground Cables, Transformers, and Switchgear was taken from Category Analysis RIN Table 5.2.1 Asset Age Profile.

- Each line item within these asset categories was aligned to the appropriate RAB category.
- The Average Age of each line item, based on its installation year, was calculated, along with the Total Asset Quantity.
- The Unit Cost for each item was taken from the AER's 2019-24 Repex Model for all items except for 3 which were unavailable in this model. For these 3 items, the unit cost was based on the prior year's rate with indexation applied. This approach was discussed with the Asset Management Team and assessed as a reasonable approach to adopt in the 2019-24 regulatory period.
- The Total Replacement Cost and the Weighted Average Age Replacement Cost were then calculated for each line item by multiplying the Unit Cost by the Total Asset Quantity and the Average Age by the Total Replacement Cost.
- The sum of the Weighted Average Age Replacement Cost was then divided by the sum of the Total Replacement Costs for each RAB asset category to give the category's Average Asset Age (based on depreciated replacement cost).
- The Estimated Residual Service Life for each category was then calculated by subtracting the Average Asset Age from the Estimated Service Life of New Assets.
- Note: Whilst Substation Land is included in the RAB values for Substations, it has been assumed to have an indefinite life. As such, it has not formed part of the residual life calculations.

For Meters, Other Long-Life assets and Other Short Life assets:

- The opening residual life at the beginning of each regulatory period was taken from the Input sheet in the RFM (based on the Final Determination PTRM). This becomes the starting point for establishing the residual life of each asset class.
- The proportionate value of each year's opening RAB values and additions amounts for each asset class from the RFM was then calculated.
- The end of year residual life for each asset class was then established by weighting the RAB proportions for the asset class against the relevant standard life of additions and the rolled forward opening residual life from the RFM.
- Where there is more than one class of asset comprising a RAB category, i.e. for Other Long Life and Short Life Assets, the resulting residual lives were weighted against the proportionate value of the opening RAB values and additions amounts for each asset class within the entire asset category.
- Residual asset lives were calculated for both Standard Control Services and Alternative Control Services asset classes.
- NB. Since Type 5 and 6 metering became contestable in December 2016, there have been only minimal ACS additions of indirect expenditure. This has simplified the Residual asset life calculation as the relevant lives are now just reduced by one year, each year.

Use of Estimated Information

Other than the data in *Table 3.3.4.2 Estimated residual lives*, which are necessarily estimated, the rest of the data in this sheet meets the AER's guideline definition of actual information.

The assumptions made for each row are included in the Methodology and Assumptions sections.

Material Accounting Policy Changes

Essential Energy has not undertaken any material changes in accounting policies.

Reliability of Information

See "Use of Estimated Information" section above, but generally this information is considered reliable.

Worksheet 3.4 – Operational data

Table 3.4.1 – Energy Delivery

Compliance with Requirements of the Notice

This section contains the total energy delivered by Essential Energy to the customer, based on the customer's metered consumption as per their invoice and relevant financial year.

Source of Information

Total energy delivered, including accruals, has been sourced from PEACE billing system using Cognos, and agrees to the Finance Gross Margin report and associated workbooks. The Finance Gross Margin report takes into account the invoice data that is still outstanding through the accrual process.

Methodology & Assumptions

Table 3.4.1 shows total energy delivered as reported in the Finance Gross Margin report and associated workbooks. Data for the 2020-21 year has been audited as part of the revenue review done on the statutory accounts audit.

The Finance Gross Margin report, including accruals, is provided by Finance as part of the end of year Board report and is subject to statutory audit.

Variable Code	Variable	Tariffs included
DOPED01	Total energy delivered	Sum of single and ToU kWh consumption from all tariffs

Use of Estimated Information

The amounts reported includes accruals for unbilled amounts for the period, however this is as provided to the Board and audited so is considered reliable.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided in this table is considered to be reliable.

Table 3.4.1.1 – Energy grouping – delivery by chargeable quantity

Compliance with Requirements of the Notice

This section contains the total energy delivered by Essential Energy to the customer based on the customer's metered consumption as per their invoice and relevant financial year.

Source of Information

Total energy delivered has been sourced from PEACE (via NRC-COGNOS) which populates the Finance Gross Margin report and associated workbooks. This Finance report takes into account the invoice data that is still outstanding through the accrual process.

Data for the 2020-21 year has been audited as part of the revenue review done on the statutory accounts audit.

Methodology & Assumptions

Data provided in Table 3.4.1.1 was sourced from the Finance Gross Margin report and associated workbooks. This report is provided by Finance as part of the end of year Board report and is subject to statutory audit.

The Finance Gross Margin report provides the consumption at the required segment levels. This is an improvement implemented for the 2019-20 year with this split of tariff components now being recorded separately in the general ledger.

Table 3.4.3

Variable Code	Variable	Segments included
DOPED0201	Energy Delivery where time of use is not a determinant	Residential Continuous and Business Continuous
DOPED0202	Energy Delivery at On-peak times	Residential TOU, Business TOU <100 MWH, Business TOU >100 MWH, Low Voltage Demand, Industrial (incl High Voltage, Subtransmission, Site Specific, Inter Distributor Transfers) – Peak component only
DOPED0203	Energy Delivery at Shoulder times	Residential TOU, Business TOU <100 MWH, Business TOU >100 MWH, Low Voltage Demand, Industrial (incl High Voltage, Subtransmission, Site Specific, Inter Distributor Transfers) – Shoulder component only
DOPED0204	Energy Delivery at Off-peak times	Residential TOU, Business TOU <100 MWH, Business TOU >100 MWH, Low Voltage Demand, Industrial (incl High Voltage, Subtransmission, Site Specific, Inter Distributor Transfers) – Off Peak component only
DOPED0205	Controlled load energy deliveries	Controlled Load 1 and Controlled Load 2
DOPED0206	Energy Delivery to unmetered supplies	Streetlighting

Use of Estimated Information

The consumption drives the revenue reported for each tariff and therefore, given the revenue associated with TOU or demand tariffs has been audited, we believe the associated consumption is accurate and reliable. The accrual process is an estimate of outstanding invoices for the period, however this is as provided to the Board and audited so is considered reliable.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided in this table is considered to be reliable.

Table 3.4.1.2 – Energy – received from TNSP and other DNSPs by time of receipt, and

Table 3.4.1.3 – Energy – received into DNSP system from embedded generation by time of receipt

Compliance with Requirements of the Notice

This section contains the total energy input into Essential Energy's network and as measured by Bulk Supply points and embedded generator NMIs.

Source of Information

Data has been sourced from an internal reporting system, Spotfire link to EDDIS, for 2020-21.

Methodology & Assumptions

Half-hourly NMI data was extracted from the Internal EDDIS Spotfire report for all of the Bulk Supply Point, Cross Border and TUoS pass through NMIs for 2020-21. This was then aggregated to total network load by half hour.

Based on the Essential Energy definition of Peak, Shoulder and Off Peak, as seen in Table 3.4.4 below, the half hourly data was aggregated into Peak, Shoulder and Off Peak buckets in Excel to determine the totals to report in the table.

Table 3.4.1.2 is not total network load, as generation load has not been added back on.

Off peak readings in the spreadsheet exclude Public holidays as this is how the majority of Essential Energy's small customers are billed, as detailed below.

Table 3.4.4 Essential Energy Time Periods

Peak	5pm to 8pm on weekdays
Shoulder	7am to 5pm and 8pm to 10pm on weekdays
Off Peak	all other times

The EDDIS Spotfire report also contains the embedded generation data and this was extracted along with the Bulk Supply Point data and calculated in the same spreadsheet for Table 3.4.1.3.

Table 3.4.1.3 also includes residential embedded generation. This information is only available through the invoicing of customers and was derived through the Finance SBR (Subsequent Billing Report) Accrual process.

Use of Estimated Information

All information for these tables was based on actual metered information from the EDDIS Cognos cube at the time of extraction, with the exception of DOPED0408 which was provided through the SBR report.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided is considered reliable.

Table 3.4.1.4 – Energy grouping – customer type or class

Compliance with Requirements of the Notice

This section contains the total energy delivered by Essential Energy to the customer based on the customer's metered consumption as per their invoice and relevant financial year.

Source of Information

Total energy delivered has been sourced from NRC-COGNOS which pulls information from PEACE into the Finance Gross Margin report and includes accruals. The Finance report takes into account the invoice data that is still outstanding through the accrual process.

Methodology & Assumptions

Data provided in Table 3.4.1.4 was sourced from the Finance Gross Margin report and associated workbooks.

The Finance Gross Margin report including accruals is provided by Finance as part of the end of year Board report and is subject to statutory audit.

The Finance Gross Margin report provides the Distribution consumption at a segment level.

Table 3.4.5 below shows how data has been aggregated from the Finance Gross Margin report into the RIN template.

Table 3.4.5

Variable Code	Variable	Segments included
DOPED0501	Residential customers energy deliveries	Sum of all Residential tariffs including Controlled Load tariffs
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	Business Continuous, Business TOU <100 MWh, Business TOU >100 MWh, Streetlighting
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	Low Voltage Demand, Small business – Opt in Demand
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	Industrial (incl High Voltage, Subtransmission, Site Specific, Inter Distributor Transfers)
DOPED0505	Other Customer Class Energy Deliveries	Not applicable

Use of Estimated Information

The accrual process is an estimate of outstanding invoices for the period, however this is as provided to the Board and audited so is considered reliable.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided in this table is considered to be reliable.

Table 3.4.2.1 – Distribution customer numbers by type or class

Compliance with Requirements of the Notice

This section contains the average number of customers by required grouping. The average was determined by calculating the average of the numbers at the start of the regulatory period and the end of the regulatory period, as requested in the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER

Note that there are no unmetered connections in Essential Energy's data that have not been reported in the customer numbers. It appears that none of Essential Energy’s unmetered customers have a National Meter Identifier (NMI) for them to be excluded in the total count.

Source of Information

Data has been sourced from an internal reporting system and existing query, via Spotfire, which extracts data from the Energy/Peace billing system. For unmetered customer numbers, these were provided by the Billing team through their SUMS and nightvision reports. Deenergised customer numbers were sourced from PowerOn Fusion.

Methodology & Assumptions

The Basic Premise count query provides the number of connected premises by tariff class for the date it was run, this report is run at the end of each month.

Certain criteria and exclusions are required to ensure the correct categories are met. These are:

- All export tariffs are removed
- All zero network code tariffs are removed as these are pre-existing retail customers
- Tariff 23000 is removed as this is a Remote Metering Fee

Table 3.4.6 shows the internal groupings aligned with requested Customer type in Table 3.4.2.1.

Table 3.4.6

Internal Groupings	Requested Customer Type
HV Demand	High voltage demand tariff customer numbers
LV Business Continuous	Non-residential customers not on demand tariff customer numbers
LV Controlled Load 1	Excluded
LV Controlled Load 2	Excluded
LV Demand	Low voltage demand tariff customer numbers
LV Residential Continuous	Residential customer numbers
LV Residential TOU	Residential customer numbers
Residential – Opt in Demand	Residential customer numbers
LV TOU over 100 MWh/yr	Non-residential customers not on demand tariff customer numbers
LV TOU under 100 MWh/yr	Non-residential customers not on demand tariff customer numbers
Small business – Opt in Demand	Low voltage demand tariff customer numbers
Site Specific	High voltage demand tariff customer numbers
Sub transmission	High voltage demand tariff customer numbers

A count is determined for the first and last months of the regulatory year to calculate the average number of Distribution Customers as per the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

Unmetered customers have been extracted from the Energy/Peace system through internal reports by the Billing team.

The guidance also required de-energised customer numbers. Unfortunately, these numbers are not accounted for in this report. The de-energised numbers have been provided through another system, PowerOn Fusion. These numbers have been included in the table under the header “Other Customer Numbers” (DOPCN0106), and are based on the difference in customer numbers between Peace and PowerOn Fusion.

Use of Estimated Information

All information for this table was based on information from the Energy billing system.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

This information is considered reliable.

Table 3.4.2.2 – Distribution customer numbers by location on the network

Compliance with Requirements of the Notice

Essential Energy has reported customer numbers in accordance with the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

Source of Information

Data has been sourced from PowerOn Fusion and calculations managed in an Access database. PowerOn Fusion makes up the central modules of Essential Energy's power Distribution Management and Outage Management

Systems (DMS/OMS). To that information has been added the unmetered customer numbers which came from Table 3.4.2.1 (DOPCN0105).

Methodology & Assumptions

The data has been collected and collated in line with the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER. The unmetered account numbers have been obtained from Table 3.4.2.1 (DOPCN0105) and added on to the total number of customers for each year (DOPCN02). They have then been allocated on a pro-rata basis across the feeder classes (DOPCN0202, DOPCN0203 and DOPCN0204).

Customers are attached to distribution substations in PowerOn Fusion. This data is updated nightly from Peace. Essential Energy has a network trace that pulls back the customer numbers from each distribution substation and the network connectivity. This links the distribution substations to a feeder segment and then to a distribution feeder. Feeders are categorised based on the guidance issued by the AER.

A count is determined at the start and end of the regulatory year to calculate the average number of Distribution Customers as per the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

Use of Estimated Information

All information for this table was based on information from PowerOn Fusion, with the addition of unmetered data which has been allocated on a pro-rata basis. This is a very small number and overall the information is considered to be actual.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

This information is considered reliable.

Table 3.4.2.3 - Distribution customer numbers by TasNetworks (D) feeder categories (TasNetworks (D) only)

Not required to be reported.

Table 3.4.2.4 - Unmetered Supply TasNetworks (D) only)

Not required to be reported.

Table 3.4.3.1 – Annual system maximum demand characteristics at the zone substation level – MW measure

Table 3.4.3.2 – Annual system maximum demand characteristics at the transmission connection point – MW measure

Table 3.4.3.3 – Annual system maximum demand characteristics at the zone substation level – MVA measure

Table 3.4.3.4 – Annual system maximum demand characteristics at the transmission connection point – MVA measure, and

Table 3.4.3.5 – Power factor conversion between MVA and MW

Compliance with Requirements of the Notice

In order to provide the actual loads for 2020/21, the Winter of 2020 and the Summer of 2020/21 was used, which included loads from 1st April 2020 to 31st March 2021. An example of the reasoning behind this method is where there is a very high load Winter, with a large peak in June and another in July. A financial year split will count these events as two separate years, so the data misses the previous and next Summer peaks. Essential Energy does not consider the use of financial years to be adequate for use in forecasting.

The AER definition of a zone substation states "a substation on a distribution network that transforms any voltage at or above 33kV to levels at or below 33kV but above 1kV". Only demands from zone substations that meet the AER definition have been included.

Source of Information

The vast majority of subtransmission substations and zone substations have reliable data recording devices. A minor number of the very small zone substations have limited methods to record the peak demand such as recloser data or maximum demand indicators from which maximum demand has been derived.

The individual zone substation demands are shown in Table 5.4.1 of the Category Analysis RIN.

For DOPSD0107 and DOPSD0110, the transmission connection point data was obtained from demand meters (via Spotfire to EDDIS).

Methodology & Assumptions

Private zone substation loads were not included in the zone substation figures.

- DOPSD0101 and DOPSD0104 - Table 3.4.3.1 "Annual system maximum demand characteristics at the zone substation level - MW measure" - These are summations of the data from Table 5.4.1 of the Category Analysis RIN.
- DOPSD0102, DOPSD0103, DOPSD0105, DOPSD0106 – Table 3.4.3.1 "Annual system maximum demand characteristics at the zone substation level – MW measure" - These are summations of the data from Table 5.4.1 of the Category Analysis RIN.
- DOPSD0107 and DOPSD0110 – Table 3.4.3.2 "Annual system maximum demand characteristics at the transmission connection point – MW measure" - These are sourced from raw data obtained from transmission connection points.
- DOPSD0108, DOPSD0109, DOPSD0111, DOPSD0112– Table 3.4.3.2 "Annual system maximum demand characteristics at the transmission connection point – MW measure" - These are calculated using the nationally consistent methodology of weather correction using historical local temperature data.

All MVA results use the summated MW and summated MVAr in the equation:

$MVA = SQRT(MW^2 + MVAr^2)$.

- DOPSD0201 and DOPSD0204 - Table 3.4.3.3 "Annual system maximum demand characteristics at the zone substation level - MVA measure" - These are summations of the source data that is used to complete Table 5.4.1 of the Category Analysis RIN
- DOPSD0202, DOPSD0203, DOPSD0205, DOPSD0206 – Table 3.4.3.3 "Annual system maximum demand characteristics at the zone substation level – MVA measure" - These are summations of actual source data that is also used to complete Table 5.4.1 of the Category Analysis RIN.
- DOPSD0207 and DOPSDO210 – Table 3.4.3.4 "Annual system maximum demand characteristics at the transmission connection point – MVA measure" – These are calculated using actual data obtained from transmission connection points and the values obtained in DOPSD0107 and DOPSD0110.
- DOPSD0208, DOPSD0209, DOPSD0211 and DOPSD0212 – Table 3.4.3.4 "Annual system maximum demand characteristics at the transmission connection point – MVA measure" – These are based on the power factor of the ratio of non-coincident peak demand to non-coincident weather corrected peak demand, applied to the DOPSD0108, DOPSD0109, DOPSD0111 and DOPSD0112 MW values.
- DOPSD0301 - Table 3.4.3.5 "Power factor conversion between MVA and MW" - This is calculated from the actual data in DOPSD0104 and DOPSD0204.
- DOPSD0302-DOPSD0314 –have been estimated based on historical power factors for each network voltage level.

Use of Estimated Information

Information is based on actual data for demand. Best practise methodology is used for weather corrected demand figures but these are by their nature estimated.

Power factors are based on estimations for the current year.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

This information is considered reliable notwithstanding the estimation used for power factors as per the Methodology and Assumptions section above.

Table 3.4.3.6 - Demand supplied (for customers charged on this basis) – MW measure, and

Table 3.4.3.7 - Demand supplied (for customers charged on this basis) – MVA measure

Compliance with Requirements of the Notice

This section contains the total demand by requested categories as per customers' invoices.

Source of Information

Data has been sourced from the billing system as per what was invoiced to the relevant customer.

Methodology & Assumptions

All data provided came from invoice data from the Peace billing system, via Spotfire, as these customers are invoiced monthly.

- DOPSD0401 - Summated Chargeable Contracted Maximum Demand - Essential Energy does not have contracted MW demand customers
- DOPSD0402 - Summated Chargeable Measured Maximum Demand - invoiced MW demand for two customers
- DOPSD0403 - Summated Chargeable Contracted Maximum Demand - invoiced MVA demand for Capacity tariffs. These charges relates to obsolete tariffs which are in the process of being rolled off.
- DOPSD0404 - Summated Chargeable Measured Maximum Demand - invoiced MVA demand. This is Essential Energy's main category for demand based tariffs.

Use of Estimated Information

All information for this table was based on actual invoiced information.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided in this table is considered to be reliable.

Worksheet 3.5 – Physical Assets

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

Compliance with Requirements of the Notice

The Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER requires the circuit length of every in-service overhead and underground subtransmission and distribution circuit to be determined for the current financial year. For Tables 3.5.1.1 and 3.5.1.2, this “circuit length” has been determined by considering each circuit (regardless of voltage) as a separate entity.

Final connections to the mains have been excluded (i.e. overhead service lines and underground service cables), as well as overhead lines and underground cables for public streetlighting.

Source of Information

A snapshot of the GIS Smallworld database was taken on 1st July. From this snapshot, overhead line and underground cable data (i.e. “cables”) were exported from GIS Smallworld using scripts.

Methodology & Assumptions

The Script filtered out all cables that were not owned by Essential Energy, where there was a responsibility value of “Private” or where the operating voltage was equal to “Streetlight” or “Service”. The Nominal Length attribute on the cable was used for the length of each cable and the results were summarised by the cables’ operating voltages.

Figures are obtained from Smallworld, our primary GIS system, and although we acknowledge there may be immaterial issues with this data, the information is considered to be actual.

Use of Estimated Information

As described above.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data that has been used for the quantities in Tables 3.5.1.1 and 3.5.1.2 has primarily come from Essential Energy’s GIS Smallworld system and although we acknowledge there may be immaterial issues with this data, it is considered to be reliable. Contributing factors to the degree of accuracy are listed below.

Data Quality:

The quality of the cable information stored in GIS Smallworld has been steadily improving over many years, however the following points describe some of the known data quality issues:

- Data quality checks regularly highlight data quality issues, however certain issues cannot be resolved without field visits, which in many cases are not warranted due to the nature of the issue and the distance required to be travelled;
- There is further work to do to capture services that go from the LV mains to the Smallworld Service Point;
- Some underground cables may be missing or drawn in the incorrect location and may not be detected because it is difficult to know exactly where they are.

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

Compliance with Requirements of the Notice

Essential Energy has, in accordance with the requirements of the Regulatory Information Notice, completed Tables 3.5.1.3 and 3.5.1.4 and the Basis of Preparation for the aforementioned tables which explains for each variable, the basis upon which Essential Energy prepared information to populate the input cells.

Source of Information

Essential Energy's information regarding Tables 3.5.1.3 and 3.5.1.4 was obtained from the following sources:

> Smallworld – specifically for Tables 3.5.1.3 and 3.5.1.4, data was sourced from:
  - feeder lengths
  - feeder phase lengths (i.e. single phase, three phase or SWER)
  - feeder linkages to fault level information
  - feeder first segment conductor type
  - feeder underground and overhead lengths
  - feeder voltage

> Sincal -– specifically for Tables 3.5.1.3 and 3.5.1.4, data was sourced from:
  - fault levels

> EE Subtransmission Feeder Ratings Version Z7.xlsx – specifically for Tables 3.5.1.3 and 3.5.1.4, data was sourced from:
  - feeder section lengths
  - feeder section ratings
  - underground and overhead lengths
  - feeder voltage

> Operational Manual: Standard Overhead Conductor: Current Rating Guide CEOM7011– specifically for Tables 3.5.1.3 and 3.5.1.4, data was sourced from:
  - Conductor and Cable ratings

> The Handbook, 2013 Edition, Olex - specifically for Tables 3.5.1.3 and 3.5.1.4, data was sourced from:
  - Conductor and Cable ratings

Methodology & Assumptions

In this section we explain the methodology Essential Energy applied to provide the required information, including any assumptions Essential Energy made.

Essential Energy has used the following methodologies and assumptions in determining the estimated overhead and underground network weighted average MVA capacity by voltage class.

Background:

It should be noted that, as the outcome of this table is a km capacity, the methods used below determine the capacity of the line with respect to the line only.

For example: A feeder is connected to a Zone Substation breaker with a rating of 100A. The feeder is made up of 3 segments - 2 segments with a thermal capacity of 200A, 10km in total, and 1 segment with a thermal capacity of 150A, 5km in total. There are no voltage constraints on the feeder capacity.

Under the weighted average capacity methodology, the feeder capacity is calculated as:

> (200 x 10 + 150 x 5) / 15 = 183A, even though the surrounding infrastructure is not capable of supplying this level of current.

Methodology Part 1:

For the subtransmission network, relatively accurate information is held on feeder sections which includes:

- Region
- Area
- Feeder Number
- From Sub/Tee
- Section Number
- To Sub/Tee
- Operating Voltage (kV)
- Is this the Minimum conductor on the feeder section?
- Summer Day Rating
- Winter Day Rating
- Summer Day Emergency Rating (1.0 m/s wind)
- Winter Day Emergency Rating (1.0 m/s wind)
- Wind and Ambient Temperature Condition
- Alias in ENMAC
- Conductor
- Design Temperature of Line Section (degrees C)
- Section Length (km)
- Construction Type
- Configuration
- Year Line Section Constructed
- OHEW type
- OHEW Dist (km)
- Summer Ambient Temp C
- Winter Ambient Temp C
- Summer Wind Average (m/s)
- Winter Wind Average (m/s)
- Summer Day (A)
- Winter Day (A)
- Summer Day (MVA)
- Winter Day (MVA)
- Diam (mm)
- Rdc 20C (ohm/km)
- 0C k (m Rac/Rdc)
- Coeffic dc resist
- Summer Day (A)
- Winter Day (A)
- Summer Day (MVA)
- Winter Day (MVA)

Derivation of ratings for Subtransmission Feeders

- Overhead conductor ratings are calculated using formulas defined in ESAA D(b)5-1988.
- Underground cable ratings are defined by the cable manufacturer.

Assumptions under Methodology Part 1:

- All subtransmission feeders are to be treated as Summer constrained and therefore Summer ratings have been used, as the Winter constrained feeders will have an insignificant effect on the results.
- All subtransmission feeders are to be treated as thermally constrained, as the voltage constrained subtransmission feeders will have an insignificant effect on the results.
- Some subtransmission feeder section ratings or lengths were unavailable and hence were not used in the calculations. It has been assumed that the feeders with missing data will not have a significant effect on the results.

Methodology Part 2:

Relatively poor information is kept on HV feeders and their ratings, particularly when considering the non-uniform rating of HV feeders along their length. For the derivation of the “weighted average MVA capacity” on HV feeders for a given voltage the following data was obtained:

- The maximum fault level along the feeder has been taken from Sincal simulations.
- The minimum fault level along the feeder has been taken from Sincal simulations.
- The length of the three phase, single phase, and SWER feeder sections for both overhead and underground have been obtained from Smallworld.
- The first conductor in the feeder has been taken from Smallworld.

The fault level data now excludes all nodes that connect two different feeders, as there is not enough information to derive which side of the switch the fault level was calculated for. This has reduced average fault levels for some feeders and increased it in others. The fault level data points are no longer filtered based on previous years. This restriction was originally implemented due to the large changes in the dataset due to adjustments in SmallWorld that were adversely affecting the calculations. The unrestricted dataset now includes some feeders that are higher than average MVA capacity, resulting in an increase of the weighted average capacity for some voltages.

Derivation of ratings

The following calculations were performed on the aforementioned data to determine the rating of each feeder:

> Averaging the minimum and maximum fault levels, to determine the average fault level along the feeder (as an alternative to determining the fault level along every finite section of the HV feeder).
> Taking the voltage based rating for all available HV feeders as 10% of the averaged fault current (if a single phase to earth fault results in a voltage of zero at the location of the fault, 10% of the single phase to earth fault will result in a 10% reduction in voltage – a 10% reduction in voltage being approximately the limit for HV feeders).
> Taking the thermal rating for all available HV feeders as the rating of the first conductor out of the substation based on the conductor type and a 50 degree Celsius rating.
> Taking the voltage based rating for all available SWER sections as 10% of the averaged fault current on the SWER section (if a single phase to earth fault results in a voltage of zero at the location of the fault, 10% of the single phase to earth fault will result in a 10% reduction in voltage – a 10% reduction in voltage being approximately the limit for HV feeders).
> Taking the actual rating for the feeder as the minimum of the thermally based rating and the voltage based rating.

Assumptions under Methodology Part 2:

> The fault current is a reasonable surrogate for determining maximum current based on voltage, however large variations in the X/R ratio of the fault away from unity will see true current carrying capacity vary according to the power factor of the load.
> HV feeders have a linear reduction in fault level.
> All HV feeders have a 50 degree Celsius rating. Whilst this is most likely not the case, Essential Energy believes it to be a reasonable assumption based on the limited data available.

Methodology Part 3:

LV Feeder ratings are virtually non-existent and many LV feeders will be voltage constrained. Based on the limited data available, Essential Energy has provided LV Feeder ratings based solely on the thermal rating of LV conductors. Essential Energy is aiming to improve the methodology for future submissions.

Assumptions under Methodology Part 3:

> All bare OH LV feeders have a 50 degree Celsius rating. Whilst this is most likely not the case, Essential Energy believes it to be a reasonable assumption based on the limited data available.
> The conductor information available is a reasonable sample of the available LV feeder stock.
> The conductors have been assumed to be three phase unless further information was available.
> All insulated overhead cables have a 75 degrees Celsius rating.
> All underground cables:
  - In duct, underground, one duct for single and three phase arrangements.
  - Where the insulation material is not known, PVC is assumed.

Methodology and Assumptions Part 4:

Calculation of "weighted average MVA capacity"

The "weighted average MVA capacity" for a given voltage is determined by assigning a weight to the rating of the feeder section based on the feeder section length divided by the total feeder length for each voltage class and construction type (overhead and underground).

"Weighted average MVA capacity" of the current year compared to previous years

The asset data used to construct the weighted average MVA capacity is highly variable due to the large amount of unknown conductors and ratings within Essential Energy's network and the process of continual data improvement. Variations in fault data and asset data may have large impacts on the weighted average MVA capacity. In most cases, this error in data will have substantially greater impact than the sum of the network upgrades during the year in question, i.e. the percentage error is considered to be greater than the actual change in value being measured.

Use of Estimated Information

Almost all data involved in the "weighted average MVA capacity" with the exception of feeder lengths can be considered to be estimated. These estimations include:

> Subtransmission feeder ratings

While subtransmission feeder ratings are calculated based on known conductor types and widely used industry principles, the weather parameters used in those calculations are based on area-wide assumptions and hence feeder ratings can be considered as best estimates.

> HV feeder ratings

HV feeders do not have uniform ratings along their length for two main reasons:

- firstly, HV feeders consist of different conductor types and phasing along their length and hence have different thermal ratings along their length
- secondly, HV feeders can have, and in Essential Energy's network the majority will have, considerable voltage drop along the length of the feeder. Hence, even if maximum thermal rating could be delivered, it would not be at voltages required under Essential Energy's license conditions.

Due to the range of HV feeder constraints and respective solutions to address such constraints, not all HV feeder augmentation results in a change to the HV feeder average fault level. As such, the fault level based method should only be considered an approximation of HV feeder capacity change. The average fault level method used by Essential Energy to formulate the HV feeder ratings as required by the RIN across available feeders is considered the best approach based on available data. Essential Energy is aiming to improve the methodology for future submissions.

This method of using fault current or short circuit current to determine network strength is used in Australian standards such as AS/NZS 61000.3.6:2001 in reference to permitted harmonic thresholds of particular electronic devices.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided in these tables is based on assumptions and estimates and caution should be used when using this data for benchmarking or decision making purposes.

Table 3.5.2.1– Distribution transformer total installed capacity

Compliance with Requirements of the Notice

The information provided reports a breakdown of transformer capacity of distribution transformers owned by Essential Energy, high voltage customers, and spare transformers owned by Essential Energy that are not currently in use.

Source of Information

This data has been obtained from:

> Current Distribution Transformer MVA extracted from WASP using SQL.

> Distribution Transformer Spare Capacity has been obtained from PeopleSoft and Cold Capacity from WASP.

> The key data used to determine private HV transformer capacity has been sourced from connection agreements and maximum demand readings for HV customers.

Methodology & Assumptions

> DPA0501 – Distribution transformer capacity owned by utility including Cold Spares

SQL Logic:

9. Distribution transformer capacity owned by utility (not including Cold Spares)

- Only Substation Sites with an Owner = “Essential Energy”.
- Only Substation Sites with a Service Status = “In Service” (Out of Service have been classified as Cold Spares).
- Excludes Substation Sites with a Substation Type = “Isolator” or “Step Up/Down” (this leaves all Distribution Substation Sites)
- Excludes Substation Sites with a SWER Primary Voltage (6.35kV, 12.7kV, 19.1kV), therefore excluding SWER Isolators in conjunction with the above item.
- kVA has been obtained from the Substation Site's “Total KVA”. If this is not available, then kVA has been derived as follows (note this has only occurred in 2% of cases):
  - if Substation Site “Total kVA” is blank, then use sum of children Transformer “kVA”.
  - if Substation Site “Total kVA” and children Transformer “kVA” fields are blank, then use Substation Site “Phases” as follows:

    3 phase = 63kVA
    1 phase = 10kVA

  - if Substation Site “Total kVA” and children Transformer “kVA” fields are blank and Substation Site “Phases” is blank, then use Substation Site “Construction Type” as follows:

    Pad/Kiosk Substation = 500kVA
    Chamber Substation = 1000kVA
    Ground Substation = 1000kVA
    All others (e.g. Pole Substation) = 10kVA

- MVA was calculated as kVA (derived if necessary as per above)/1000 and summed.

10. Cold Spares (added to item (1) once determined)

- Cold Spare Capacity = Cold (Out of Service) Distribution Transformers + Spare Distribution Transformers
- Cold (Out of Service) Distribution Transformers (source = WASP):
  - All Substations Sites with an Owner = “Essential Energy” and a Service Status = “Out of Service”
  - kVA has been obtained from the Substation Site's “Total KVA”. If this is not available, then kVA has been derived as follows:
    - if Substation Site “Total kVA” is blank, then use sum of children Transformer “kVA”.
    - if Substation Site “Total kVA” and children Transformer “kVA” fields are blank, then use Substation Site “Phases” as follows:

      3 phase = 63kVA
      1 phase = 10kVA

    - if Substation Site “Total kVA” and children Transformer “kVA” fields are blank and Substation Site “Phases” is blank, then use Substation Site “Construction Type” as follows:

      Pad/Kiosk Substation = 500kVA
      Chamber Substation = 1000kVA
      Ground Substation = 1000kVA
      All others (e.g. Pole Substation) = 10kVA

  - Excludes Substation Sites with a Substation Type = “Isolator” or “Step Up/Down” (this leaves all Distribution Substation Sites).
  - Excludes Substation Sites and Transformers with a SWER Primary Voltage (6.35kV, 12.7kv, 19.1kV), therefore excluding SWER Isolators in conjunction with the above item.
  - MVA was calculated as kVA (derived if necessary as per above)/1000 and summed.
- Spare Distribution Transformers (source = PeopleSoft):
  - Polemount and padmount transformers stock items booked into depots/stores as “spares” in PeopleSoft.
  - kVA has been obtained from the Transformer stock item description.
  - MVA was calculated as kVA (derived if necessary as per above)/1000 and summed.

> DPA0502 – Distribution transformer capacity owned by High Voltage Customers

The methodology used to estimate the capacity of distribution transformers owned by Essential Energy's high voltage customers is based on 110% of customer maximum demand as listed in their Connection Agreement.

. This logic differs from previous years of using peak demand calculations for each customer. Previous years have seen fluctuations in capacity assessment, when connected sites have seen growth.The transformer capacity includes only high voltage "load" (consuming) customers. Generation customers have been excluded.

> DPA0503 – Cold spare capacity included in DPA0501
  - Cold Spare Capacity = Cold (Out of Service) Distribution Transformers + Spare Distribution Transformers
  - Cold (Out of Service) Distribution Transformers (source = WASP):
    - All Substations Sites with an Owner = "Essential Energy" and a Service Status = "Out of Service"
    - kVA has been obtained from the Substation Site's "Total KVA". If this is not available, then kVA has been derived as follows:
      > if Substation Site "Total kVA" is blank, then use sum of children Transformer "kVA".
      > if Substation Site "Total kVA" and children Transformer "kVA" fields are blank, then use Substation Site "Phases" as follows:

        3 phase = 63kVA
        1 phase = 10kVA

      > if Substation Site "Total kVA" and children Transformer "kVA" fields are blank and Substation Site "Phases" is blank, then use Substation Site "Construction Type" as follows:

        Pad/Kiosk Substation = 500kVA
        Chamber Substation = 1000kVA
        Ground Substation = 1000kVA
        All others (e.g. Pole Substation) = 10kVA

    - Excludes Substation Sites with a Substation Type = "Isolator" or "Step Up/Down" (this leaves all Distribution Substation Sites).
      > Excludes Substation Sites and Transformers with a SWER Primary Voltage (6.35kV, 12.7kV, 19.1kV), therefore excluding SWER Isolators in conjunction with the above item.
      > MVA was calculated as kVA (derived if necessary as per above)/1000 and summed.
  - Spare Distribution Transformers (source = PeopleSoft):
    - Polemount and padmount transformers stock items booked into depots/stores as "spares" in PeopleSoft.
    - kVA has been obtained from the Transformer stock item description.
    - MVA was calculated as kVA (derived if necessary as per above)/1000 and summed.

Use of Estimated Information

> Essential Energy has used estimated information when there is no 'Date Constructed' for the Substation Site or Transformer as per logic detailed above. This estimation is required in a small number of cases and provides for a good estimation.

> Essential Energy has used estimated information when there is no 'Total kVA' for the Substation Site as per the logic detailed above. This was only performed in 2% of cases. The methodology used to estimate the kVA in these instances is considered to provide a reasonable approximation and was determined using averages and most common kVA by Substation Type.

> For DPA0502, Essential Energy has estimated the capacity of distribution transformers owned by its high voltage customers, as accurate records of the assets on these networks do not exist.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The base figures used for the distribution transformer capacity are dependent on the accuracy of the data within the WASP and PeopleSoft databases as well as assumptions made as per this Basis of Preparation document for Table 3.5.2.

For DPA0502, the data provided is based on assumptions and estimates and is not considered reliable. Essential Energy cannot report with any level of accuracy on the private equipment owned by its high voltage customers, or the operating and maintenance costs of equipment which it does not own or manage.

Table 3.5.2.2 – Zone substation transformer capacity

Compliance with Requirements of the Notice

The information provided reports on the transformer capacity of distribution zone substation transformers owned by Essential Energy. The data is broken down according to transformation steps as well as those that are not currently in use. This is in line with the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER. Further detail has been provided in the subsequent subheadings to address compliance requirements.

Source of Information

This data has been obtained from:

- Current Zone Substation Transformer MVA extracted from the WASP system using SQL and the PowerOn operational system.

Methodology & Assumptions

SQL Logic:

- All zone substation power transformer assets where the Owner <> “Private” (all others should be Essential Energy owned).
- All zone substation power transformers with a Service Status of:
  - “In Service”, “Out of Service”, “Proposed”, “System Spare”, “Under Construction”, or “Under Repair”.
- Excludes zone substation power transformers with a Type of:
  - “Regulators”, “SWER Isolators”
- MVA has been obtained from the “Maximum Rating (MVA)” attribute. If blank, it is assumed to be 5 MVA (note that this occurred in <1% of cases).
- The totals for DPA0601, DPA0602 and DPA0603 have been determined based on the “Usage” attribute on the zone substation power transformer assets as follows:
  - DPA0601 = “Step 1 of 2 to distribution voltage”
  - DPA0602 = “Step 2 of 2 to distribution voltage”
  - DPA0603 = “Step 1 of 1 to distribution voltage”
  - DPA0604 = Total MVA of all transformers (including spares).
  - DPA0605 - has been determined using the “AER Cold Standby” attribute which has a value of ‘Spare’ or ‘Cold Standby’.

Use of Estimated Information

Essential Energy has used estimated information when there is no “Maximum Rating (MVA)” for zone substation power transformers as per the logic detailed above. This only occurred in <1% of cases. The methodology used to estimate the MVA in these instances is considered to provide a reasonable approximation and was determined using averages and most common MVA by Power Transformer Type.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The base figures used for the current zone substation transformer capacity are dependent on the accuracy of the data within the WASP database and the Zone Substation Manuals as well as assumptions made as per this Basis of Preparation document for Table 3.5.2.2.

The 2018-19 cold spare capacity (DPA0605) was calculated from WASP since the data is now available in the system. The total capacity (DPA0604) now includes the cold spare capacity

Table 3.5.2.3 – Distribution – other transformer capacity

Not required to be reported.

Table 3.5.3 – Public lighting

Compliance with Requirements of the Notice

The information provided reports the number of public lighting luminaires and public lighting poles within Essential Energy's distribution area.

Source of Information

The data used to populate the number of public lighting luminaires and poles was extracted from WASP as at 1 July 2021. The 'All Assets' report as at 30 June 2021 excluding; security lighting 'SCL' category, 'out of service assets, "private" and "metered" in accordance with respective "funded by" field represent the total number of public lighting assets owned and maintained or only maintained by Essential Energy for FY21.

Methodology & Assumptions

Assumptions:

> 'Funded By' fields denote the responsibility to maintain the public lighting asset.
> Assets with the same 'Asset Label' are unique poles in different vicinities.
> Public lighting luminaires has been calculated by summing the total of 'Asset IDs.

Essential Energy does not delineate between a public lighting pole and a public lighting column as such public lighting poles has been calculated by excluding 'shared or no pole' from the 'dedicated support type' column and excluding 'bridge', 'building', 'ground', 'suspension' and 'blanks' from the 'support type' field. The public lighting poles has been calculated by summing the total of the 'Asset label' column.

Use of Estimated Information

The data contains no estimates as it has been sourced directly from WASP.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

This information is considered reliable.

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Worksheet 3.6 – Quality of service

Table 3.6.1 - Reliability

Compliance with Requirements of the Notice

In this section we demonstrate how the information provided is consistent with the requirements of this Notice.

The data for 2020-21 has been collected and collated in line with the definitions.

Customer numbers include active NMIs with an active or inactive account. This is the way data has been collected and stored since PowerOn Fusion went live in November 2012.

The Threshold for Major Event Days (TMED) for 2020-21 was applied as per the definition.

Source of Information

Data is sourced from PowerOn Fusion and calculations managed in an Access database. PowerOn makes up the central modules of Essential Energy's power Distribution Management and Outage Management Systems (DMS/OMS).

The spreadsheet used to collate the data is titled: “RIN Tables Workpapers 20-21”.

Methodology & Assumptions

The data has been collected and collated in line with the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

The Threshold for Major Event Days (TMED) for 2020-21 was applied as per the definition.

In the RIN Access Database 2020-21, the following query was run for the financial year:

> Run and View Monthly Reliability Reporting Data
  - This query rolls up all outages into filtered definitions with Customers Affected and Customer Minutes Lost at region and category level.
  - RIN Whole Net SAIDI/SAIFI 1 summates the Monthly Reliability Reporting Data.
  - RIN Whole Net SAIDI/SAIFI 2 calculates the SAIDI/SAIFI using Avg Cust Base RIN query.

> As a cross-reference:
  - In the workpaper on sheet ‘20-21 data’ – roll up categories by operational area to total Essential Energy categories and finally into total Essential Energy.

> Using Average Customer Base RIN to calculate SAIDI (Customer Minutes Lost/Ave Cust Count) and SAIFI (Customers Affected/Ave Cust Count).
  - DQS0101 & DQS0103 = Total Unplanned SAIDI and SAIFI.
  - DQS0102 & DQS0104 = Total Unplanned – Transmission – Directed to De-energise – Total Fire Ban-No Fault Found = DNI Unplanned SAIDI and SAIFI.
  - DQS0105 & DQS0107 = Normalised + Transmission + Directed to De-energise + Total Fire Ban-No Fault Found SAIDI and SAIFI.
  - DQS0106 & DQS0108 = Normalised SAIDI and SAIFI.

Use of Estimated Information

There was no use of estimated information.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

Information has been sourced from current systems and management is comfortable that the information is reliable.

Table 3.6.2 – Energy not supplied

Compliance with Requirements of the Notice

This section contains an estimate of the energy that was not supplied as a result of Customer Interruptions as per the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

Source of Information

Data has been sourced from reported Planned customer minute off-supply and Unplanned customer minutes off-supply, from Annual RIN Table 3.6.8.

Methodology & Assumptions

Based on the information available, the estimated kWh was determined by calculating an average kWh use per minute for the financial year, based on the total consumption divided by the total number of customers divided by the number of minutes in a year. This information was then applied by Feeder to the data from Table 3.6.8 of the annual RIN.

These figures are the sum of the planned and unplanned MWh not supplied, as reported in Table 3.6.8 of the Annual RIN.

Use of Estimated Information

All information for these tables was based on an aggregate network level and a best estimate.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The 2021 GWh supplied were as reported in the 2020-21 Annual Regulatory Accounts.

Table 3.6.3 – System losses

Compliance with Requirements of the Notice

This section contains the proportion of energy that is lost in the distribution of electricity from the transmission network to Essential Energy customers.

Source of Information

The result is formula driven and data utilised in Table 3.6.3 came from Table 3.4.1.2 and Table 3.4.1.3 for Electricity imported, while Electricity delivered was from Table 3.4.1.

Methodology & Assumptions

The methodology used in this section was as provided in Equation 2 of the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER, as shown below:

System losses = {(electricity imported – electricity delivered) / (electricity imported)} x 100

The electricity imported is the sum of the Energy received from the TNSP plus the Energy received into the DNSP system from embedded generation.

Use of Estimated Information

The calculation is based on tables that have been provided. Please refer to the sections relating to Tables 3.4.1, 3.4.1.2 and 3.4.1.3 in this Basis of Preparation document. These tables are designated as actual, so this formula result is also classified as actual.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided is considered reliable.

Table 3.6.4 – Capacity utilisation

Compliance with Requirements of the Notice

This section follows the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER which defines the requirements as:

"Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year. Essential Energy must report the sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity. For the purpose of this measure, thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant). This must be the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity should similarly be the continuous rating."

Source of Information

The result is formula driven and data utilised in Table 3.6.4 came from Table 3.4.3.3 and Table 3.5.2.2.

Methodology & Assumptions

Essential Energy has ignored feeder capacity and used:

Table 3.4.3.3 Non–coincident Summated Raw System Annual Maximum Demand divided by Table 3.5.2.2 Total installed capacity for second step transformation where there are two steps to reach distribution voltage + Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage.

Use of Estimated Information

The calculation is based on data in tables that have been provided. Please refer to the sections relating to Tables 3.4.3.3 and 3.5.2.2 in this Basis of Preparation document. These tables are designated as actual, so this formula result is also classified as actual.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided is considered reliable.

Worksheet 3.7 – Operating environment

Table 3.7.1 – Density factors

Compliance with Requirements of the Notice

This section has been completed as per the formulas provided in the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

Source of Information

“Customer Density” sources information from Table 3.4.2.2 Total customer numbers and Table 3.7.3 Route line lengths.

“Energy Density” sources information from Table 3.4.1 Energy delivered and Table 3.4.2.2 Total customer numbers.

“Demand Density” sources information from Table 3.4.3.3 Annual system maximum demand, DOPS0201, and Table 3.4.2.2 Total customer numbers.

Methodology & Assumptions

The methodology used in this section was as provided in the Economic Benchmarking RIN Instructions and Definitions guidance issued by the AER.

Customer density is the total number of customers divided by the route line length of the network.

Energy Density is the total MWh delivered to the customer divided by the total number of network customers.

Demand density is the non-coincident Maximum Demand at zone substation level, in kVA units, divided by the total number of network customers.

Use of Estimated Information

These calculations are based on actual data reported in Tables 3.4.1, 3.4.2.2, 3.4.3.3 and 3.7.3 and explained in this Basis of Preparation document above.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data provided is considered reliable.

Table 3.7.2 – Terrain factors

Compliance with Requirements of the Notice

This section demonstrates how the information provided is consistent with the requirements of this Notice.

Source of Information

- Vegetation Information Management System (VIMS)
- WASP
- Smallworld
- 2018 LiDAR Incursion Data

Methodology & Assumptions

Rural proportion (Actual)

Rural proportion was calculated as Rural Route Line Length divided by Total Route Line Length

Urban and CBD vegetation maintenance spans (Actual)

We take the individual values from 2.7.1 (number of maintenance spans) for each urban zone and sum them up.

Rural vegetation maintenance spans (Actual)We take the individual values from 2.7.1 (number of maintenance spans) for each rural zone and sum them up.

Total vegetation maintenance spans (Actual)

This is the sum of Rural and Urban vegetation spans outlined in the previous two metrics (i.e. Urban and CBD Vegetation Maintenance Spans plus Rural Vegetation Maintenance Spans).

Total number of spans (Actual)

Total number of spans is generated from running a script out of SmallWorld

Average urban and CBD vegetation maintenance span cycle (Estimate)

We run an extract out of WASP for all veg defects created since 2011. We pivot this data against the VMA and generate new columns which represent total veg defects created per year. We then add new calculated columns (1 per year) which generate a value of 1 if the total count of defects > 10. If the value is less than 10 then it scores a 0. We then create a calculated column that takes the total number of years and divides this by the total score from all years. Therefore, in a 9 year period if we see a score of 4 (i.e. 4 years where the total defect count is > 10 for each year) then we would derive a frequency of 2.25 (i.e. VMA cut on average every 2.25 years). We then pivot this data table against the urban/rural classification which gives us an average frequency per rural VMA.

Average rural vegetation maintenance span cycle (Estimate)

As per “Average urban and CBD vegetation maintenance span cycle” above.

Average number of trees per urban and CBD vegetation maintenance span (Estimate)

This is an average of the “Average number of trees per maintenance span” per zone (from 2.7.1) averaged over the urban zones.

Average number of trees per rural vegetation maintenance span (Estimate)

This is an average of the “Average number of trees per maintenance span” per zone (from 2.7.1) averaged over the rural zones.

Average number of defects per urban and CBD vegetation maintenance span (Actual)

We take the total number of veg tasks and divide this by the unique span count in the same data set to derive an average defect per maintenance span. As an example, if we had 1000 tasks in the sample data set and within that set we did a unique count of the SpanID (SpanID is the concatenated Pole1 and Pole2 fields) and found 900 unique span IDs we would conclude that there was 1.11 defects per maintenance span. The result is pivoted against the urban/rural classification to produce both an urban and rural result.

Average number of defects per rural vegetation maintenance span (Actual)

See above “Average number of defects per urban and CBD vegetation maintenance span”.

Tropical proportion (Estimate)

Climate data obtained by BOM was overlaid with network spans in Smallworld. Any Span in a Grid Code area 2 (see definitions in table below) was reported as being in a tropical area.

Grid Code	Classification	Grid Code	Classification
1	Hot humid Summer	4	Hot dry Summer, cold Winter

2	Warm humid Summer	5	Warm Summer, cool Winter
3	Hot dry Summer, mild Winter	6	Mild warm Summer, cold Winter

http://reg.bom.gov.au/jsp/ncc/climate_averages/climate-classifications/index.jsp

Standard vehicle access (Estimate)

Standard vehicle access data was sourced from Smallworld. A query was run returning line length within 50m of the centreline of selected road classifications which were deemed to be two wheel drive suitable. Classifications selected were Arterial Road, Collector Road, Local Road, Sub-Arterial Road, Highway, Lane/pathways and 2WD Tracks. The method used is sound but only yields an estimate based on the assumption that if there is a 2WD accessible road within a certain distance of the conductor, then that portion of the network is likely to be accessible from a standard 2WD vehicle.

Bushfire risk (Estimate)

Essential Energy regard all rural VMAs to be a Bushfire Risk.

Use of Estimated Information

The methodology used relies on establishing a find rate based on historical cutting data in VIMS and this represents the numbers of spans that would typically need to be actioned in a given vegetation cycle. The numbers of spans that would need to be cut in actuality would be influenced by a number of factors that are impossible to predict such as weather and contractor issues. Additionally, we are using route line length and bay/span counts derived from Small World circuit data using various scripts. The degree of accuracy cannot be determined when converting circuit/conductor data into distance data therefore it would need to be regarded as an estimate.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

As described in the Methodology and Assumptions section above, this information includes estimations and caution should be exercised if using this for decision making or benchmarking purposes.

Table 3.7.3 – Service area factors

Compliance with Requirements of the Notice

The Notice requires the route length of overhead lines and underground cables to be determined for the current financial year. For Table 3.7.3, the route length disregards the number of circuits that span between two poles and uses the length of any one of the circuits as the route length.

Final connections to the mains have been excluded (i.e. overhead service lines and underground service cables), as well as overhead lines and underground cables for public streetlighting.

Source of Information

Overhead line and underground cable data (i.e. “cables”) and pole data was exported from GIS Smallworld using FME and saved as spatial files as at the first of July. Data is considered to be actual.

Overhead line route lengths

The pole and cable data was analysed using Smallworld to determine where Essential Energy owned overhead cable spans were shared by other circuits, and if they were, these circuits were reduced to a single circuit to represent the route length for each span. The highest voltage between the two poles was assigned as the voltage of the span.

Underground cable route lengths

The cable data was analysed using FME to determine where Essential Energy owned underground cables run parallel to other underground cables. Where there are cables in parallel, the part of any cables that are in parallel except the one with the highest voltage are removed.

Methodology & Assumptions

The Script includes all spans that were owned by Essential Energy or flagged as privately owned and includes all operating voltages except Services.

Figures obtained from GIS Smallworld are assumed to be actual, even though there are some data inconsistencies. Information in Smallworld is continually being updated and refined and although this may lead to changes year on year, they are considered immaterial and management are not aware of significant data issues.

Overhead lines

Data extracted from Smallworld is from the overhead spans dataset. There is a flag on each span which is derived by a database trigger that identifies if spans are underbuilt (i.e. two circuits positioned on top of each other).

Spans where underbuilt is set to yes are excluded.

Underground cables

Underground cables are generally drawn geoschematically in relation to land parcel boundaries. Where multiple conductors exist at the same location, they are drawn offset from each other in the GIS. To determine the route length of underground cables, it was assumed that if part of a cable was drawn in parallel to part of another cable in the GIS (within a tolerance of four metres), it shared a trench, and therefore the route length was the length of only one of the cables in parallel. If a cable did not have another cable in parallel, then that cable (or part thereof) was accepted as the route length.

Use of Estimated Information

This information is considered to be actual.

Material Accounting Policy Changes

Not applicable.

Reliability of Information

The data that has been used for the quantity in Table 3.7.3 has come from Essential Energy's GIS Smallworld system.

The quality of the cable information stored in GIS Smallworld has been steadily improving over many years, however the following points describe some of the known data quality issues:

- Data quality checks regularly highlight data quality issues, however certain issues cannot be resolved without field visits, which in many cases are not warranted due to the nature of the issue and the distance required to be travelled;
- Some underground cables may be missing or drawn in the incorrect location, and may not be detected because it is difficult to know exactly where they are.

The data provided in these tables is based on the current data in the GIS Smallworld system and is generally considered to be reliable.