BASIS OF PREPARATION
RESPONSE TO RESET RIN

Version updated as at 29 May 2014

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Purpose

Essential Energy must explain, for all information in the category data (historic) *regulatory templates* the basis upon which the information was prepared (the Basis of Preparation).

The Basis of Preparation must be a separate document (or documents) that Essential Energy submits with its completed *regulatory templates*.

This document is Essential Energy's Basis of Preparation in relation to Audited Reset RIN data required to be submitted to the AER by 31 May 2014.

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.

Essential Energy must include in its Basis of Preparation, any other information prepared in accordance with the requirements of the Notice (including this document).

The AER has set out what must be in the basis of preparation. This is set out in Table 1 below:

Table 1

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: (i) why an estimate was required, including why it was not possible for Essential Energy to use Actual Information; (ii) 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.

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 *regulatory templates*.

When reporting an audit opinion or making an attestation report on the *regulatory templates* presented by Essential Energy, an auditor or assurance practitioner shall opine or attest by reference to Essential Energy's basis of preparation.

Structure of this document
This document is structured as follows:

- We outline our general approach to developing our response to the RIN. We identify key systems used to provide data, note issues relating to data quality, and make comments on the reliability of the data for benchmarking purposes.

- We set out our response to worksheets 2.1 to 7.7, in accordance with the AER's instructions. We note that Worksheets 1.1 and 1.2 require no input material.

General approach

In this section, we identify our approach to collecting and preparing information.

A key concern of Essential Energy is that the AER may use information which is of a poor quality to make regulatory determinations.

Essential Energy has identified the reliability of the information, and set out where caution should be applied by the AER in the application of the data to benchmarking models. We note that this issue has been raised with the AER in consultations relating to this notice.

1.1 Systems used to provide data

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.

1.2 Data quality issues

In previous consultations on the RIN, we have raised significant concerns with providing historical data in the form required by the AER. We continue to outline our concerns in relation to the detailed templates submitted.

1.3 Approaching our obligations under the NEL

Our view of the NEL is that a DNSP is only obligated to provide information that is available, that is, data which has been historically collected in our systems. In cases, where that information cannot be provided in the form required by the AER from our systems, we would have a reasonable excuse under section 28(5) of the NEL not to comply with that element of the notice. We have strong doubts that a RIN can require a business to prepare information by way of estimate that cannot be reasonably derived from information currently held in its systems.

Our understanding of the term 'prepare' relates to a power the AER has to compel a DNSP to collect information in the form required by the AER for future periods (for example, by developing new systems) rather than to manipulate historical data in potentially inaccurate ways. We suggest that the AER should give more careful consideration to whether it has appropriately informed itself of the distinction under section 28D of the NEL between the ability of a RIN to require existing information to be provided and the ability to require information to be prepared, maintained and kept on a going forward basis.

Despite this, Essential Energy has prepared and included the estimated data to the best of its knowledge.

1.4 Recognition by AER that 'best estimates' are not robust

The AER has acknowledged that if we are compelled to provide best estimates then there is potential for the data to lack robustness. Essential Energy has addressed the implications of using best estimates which are not robust in its Basis of Preparation to accompany the final Audited Information.

1.5 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, then information has been estimated on the basis which Essential Energy considers provides 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 variations have been identified and explained.

Essential Energy has implemented an internal colour coding system to the numbers inputted in the Rest RIN template to illustrate what is deemed to be actual or estimated information. This coding is shown below and has been used in the template with estimated data only to indicate how reliable the data is.

Colour Code	Availability of data from NSP's primary system	Additional work around/estimation techniques	Likelihood to pass an audit	Management comfort that information is fit for purpose
Green	Available and verifiable	**Simple** – no additional work or minor work around (e.g. source data from a secondary system)	Likely	Comfortable
Yellow	Available but with some gaps	**Moderate** – estimate based on statistically significant sample size	Possible but unlikely	Comfortable
Orange	Little or no data available	**Complex** – estimate based on formula, standard parameters or other source	Not likely	Not comfortable
Red	Little or no data available	**Impossible** – rough estimate (e.g. rule of thumb from experience) or not possible	Not likely	Not comfortable

1.6 Reliability of applying data to benchmarking

We consider that the application of benchmarking to guide regulatory decision making would result in error, leading to outcomes that are detrimental to the long term interests of customers. Our view is based on the following reasons:

- As noted in the section on data quality, there is recognition by the AER that data quality from best estimates will not be of a robust quality, and may not pass audit and reviews. This document identified where material has been developed from best estimates and the confidence we have in that data. We note in this respect that models such as TFP are based on the interaction of multi-variables. If a data series is inaccurate, it can significantly alter the findings of the model and lead to misleading conclusions.
- We are not convinced that benchmarking tools such as Total Factor Productivity (TFP) can be used to infer relative efficiency of DNSPs over time. We consider that the models cannot adequately normalise for differences between DNSPs, and do not provide meaningful assessment of the apparent differences in productivity levels. For example, TFP will show that a firm that replaces ageing assets has declining levels of capital productivity, as the model would show higher prices for capital while maintaining existing service levels. In our view this would be driven by the age of the asset base which is likely to vary between DNSPs.
- We consider that benchmarking models such as TFP do not provide the AER with guidance on how to target its review of expenditure forecasts, as the information provided is at too high a level to identify potential areas of efficiency. The models and data collected will not provide any guidance on the underlying drivers of apparent productivity, and therefore does not provide useful analysis on which areas to review in a DNSP's capex and opex forecasts.

1.7 Essential Energy's preparation costs

The costs incurred by Essential Energy in terms of staffing resources to completing the RIN have been considerable. Further considerable costs will be incurred in building or modifying systems to capture the information going forward which is not otherwise required for Essential Energy's operational activities.

As a general comment on costs, we are also concerned with the number of RINs, and the far-reaching level of information requested within each RIN. Our understanding of the AER's intentions on future annual reporting is that DNSPs will be required to submit three RINs each year; the completion and submission of an annual benchmarking RIN, the completion and submission of the current annual RIN and the possible completion and submission of the category analysis RIN. We submit that not only does this place significant regulatory burden on DNSPs, it also seems to be a costly duplication of effort and information which would contribute to the on-going costs for customers.

1.8 Financial data

Essential Energy has prepared an overarching basis of preparation relating to financial data used in the RIN tables where "as incurred" financials are requested. The basis of preparation below covers tables 2.2.1, 2.3.3.2, 2.3.4, 2.4.6, 2.6.1, 2.7.2, 2.8.2, 2.9.1A, 2.10.1, 2.10.2, 2.12, 2.16.2, 2.16.3, 2.16.4, 2.17.1, 2.17.2, 2.17.3, 2.17.4 and 4.2.2. The financial information provided is in accordance with the definitions as provided by the AER.

General Approach

A master file of financial data has been prepared which ensures that the RIN reset templates reconcile to the final regulatory accounts as submitted to the AER for 2009/10 to 2012/13 years.

The overarching basis of preparation for financial data is to use, where possible:

- the actual regulatory costs category totals that map to individual RIN sheets or tables,
- these totals are disaggregated where the RIN templates require lower levels of detail.
- The disaggregation is based on the actual statutory and management account cost category structures.
- A cost mapping matrix is constructed using statutory actual accounts cost categories that align to the costs categories in the RIN tables.
- This matrix is then used to apportion the regulated cost totals into the RIN tables.

This means the financial information in the RIN templates is not the exact actual financial information as there are adjustments made to the actuals in the preparation of the regulatory accounts; therefore the financials are the best representation of the final regulatory accounts using the actual statutory account cost category splits.

The forecast data for the FY15-19 years is based on the cost data from Regulatory Output Model (ROMO), which is the model underpinning Essential Energy's Substantive Regulatory Proposal (SRP).

The FY14 data is based on the FY14 forecast as per the SRP, using the same principles above.

Source of information

A Cognos dataset of PeopleSoft historical data has been extracted and reconciled to relevant management and statutory accounts to ensure its validity. The underlying cost structures in this data set have been mapped to the Regulated accounts and RIN returns to determine the basis of allocation. Cost matrices using Project Types Levels and Resource Categories have been constructed to provide the necessary breakdowns required in the RIN tables.

Methodology and Assumptions

Where the breakdown analysis of PeopleSoft data was not sufficient to satisfy the RIN requests additional Mapping tables were requested from Subject Matter Experts (SMEs) in the appropriate Operational areas.

System	**Data set**
PeopleSoft	Historic & current data
ROMO Forecasting Model	Current Version

Essential Energy changed its overhead allocation policy and methodology from the 2009/2010 year, in which overheads were allocated on a labour hour basis, to a basis of allocation on direct dollars in the 2010/11 and subsequent years.

Use of estimated information

Where data has not been previously forecasted, current unit cost data has been applied to estimated volume units supplied by Operational Subject Matter Expert.

Reliability of information

The underlying financial information in the RIN templates is a reasonably accurate representation of the regulatory accounts based on Essential Energy's underlying cost categories and therefore considered to be reliable. Where the RIN templates do not align to either, the previous regulatory account costs categories and/or, Essential Energy's internal cost categories, subjective subject matter expert (SME) mapping has been used. There is a risk that the aggregated or disaggregated costs mappings may not align to the true intent of the RIN categories and as such caution should be used when using it for benchmarking or decision making purposes. There is real risk that the financials to physical units at a line level may also not align, as unit data has not always been captured at the level of detail as required in the RIN and has been prepared using a different basis of preparation compared to the financials. The unit to financial analysis should not be relied on.

Worksheet 2.1 – Expenditure Summary

2.1.1 Standard control services capex

Compliance with requirements of the notice

This section contains summary data of previous, current and forecast capex for Standard Control Services, broken up into various categories. It also contains a balancing item and a line for Capital Contributions.

Source of information

This table is mainly a summary of capex shown in subsequent tables of the Reset RIN template, and as such, the subsequent tables in the Reset RIN template are the main source of data for this table.

Previous RINs have also been used to provide the total capex figure which was required for the calculation of the Balancing Item, as well as the capital contributions amount.

Calculations used in the Substantive Regulatory Proposal for the 2014 AER Determination were also used for the forward estimates of total capex and capital contributions.

Methodology and Assumptions

As most of the data shown in this table is a summary of data found in subsequent tables in the Reset RIN template, the table cells are linked to the appropriate cells in other tables in the Reset RIN template.

The Balancing Item was calculated by obtaining the total capex figure from previous RINs or Substantive Regulatory Proposal calculations, and deducting from it the capex in the table.

Capital Contributions were obtained from previous RINs or Substantive Regulatory Proposal calculations.

We have provided a reconciliation of the balancing items in tables 2.1.1, 2.1.2, 2.1.3, and 2.1.4 in the file *2.1 Expenditure Summary Tables Reconciliation_2014_05_27 .xlsx* which is provided as an attachment.

Use of estimated information

Forecast data is considered to be estimated information and therefore caution should be used when using this information for benchmarking or decision making purposes.

Reliability of information

Data sourced from previous audited RINs for the respective years is considered to be reliable. Data sourced from other tables within the Reset RIN template may be based on assumptions and estimates and should be used with caution when using for benchmarking or decision making purposes.

2.1.2 Standard control services opex by category

Compliance with requirements of the notice

This section contains summary data of previous and current opex for Standard Control Services, broken up into various categories. It also contains a balancing item.

Source of information

This table is mainly a summary of opex shown in subsequent tables of the Reset RIN template, and as such, the subsequent tables in the Reset RIN template are the main source of data for this table.

Previous RINs have also been used to provide the total opex figure which was required for the calculation of the Balancing Item.

Methodology and Assumptions

As most of the data shown in this table is a summary of data found in subsequent tables in the Reset RIN template, the table cells are linked to the appropriate cells in other tables in the Reset RIN template.

The Balancing Item was calculated by obtaining the total opex figure from previous RINs and deducting from it the opex in the table.

We have provided a reconciliation of the balancing items in tables 2.1.1, 2.1.2, 2.1.3, and 2.1.4 in the file *2.1 Expenditure Summary Tables Reconciliation_2014_05_27 .xlsx* which is provided as an attachment.

Use of estimated information

Data relating to forecasts in relation to the remainder of the 2014 regulatory year is considered to be estimated information.

Reliability of information

Data sourced from previous audited RINs for the respective years is considered to be reliable. Data sourced from other tables within the Reset RIN template may be based on assumptions and estimates and should be used with caution for benchmarking or decision making purposes.

2.1.3 Alternative control services capex

Compliance with requirements of the notice

This section contains summary data of previous, current and forecast capex for Alternative Control Services, broken up into various categories. It also contains a balancing item.

Source of information

This table is chiefly a summary of capex shown in subsequent tables of the Reset RIN template, and as such, the subsequent tables in the Reset RIN template are the main source of data for this table.

Previous RINs have also been used to provide the total capex figure which was required for the calculation of the Balancing Item.

Methodology and Assumptions

As most of the data shown in this table is a summary of data found in subsequent tables in the Reset RIN template, the table cells are linked to the appropriate cells in other tables in the Reset RIN template.

The Balancing Item was calculated by obtaining the total capex figure from previous RINs and deducting from it the capex in the table.

We have provided a reconciliation of the balancing items in tables 2.1.1, 2.1.2, 2.1.3, and 2.1.4 in the file *2.1 Expenditure Summary Tables Reconciliation_2014_05_27 .xlsx* which is provided as an attachment.

Use of estimated information

Forecast data is considered to be estimated information.

Reliability of information

Data sourced from previous audited RINs for the respective years is considered to be reliable. Data sourced from other tables within the Reset RIN template may be based on assumptions and estimates and should be used with caution for benchmarking or decision making purposes.

2.1.4 Alternative control services opex

Compliance with requirements of the notice

This section contains summary data of previous, current and forecast opex for Alternative Control Services, broken up into various categories. It also contains a balancing item.

Source of information

This table is mainly a summary of opex shown in subsequent tables of the Reset RIN template, and as such, the subsequent tables in the Reset RIN template are the main source of data for this table.

Previous RINs have also been used to provide the total opex figure which was required for the calculation of the Balancing Item.

Methodology and Assumptions

As most of the data shown in this table is a summary of data found in subsequent tables in the Reset RIN template, the table cells are linked to the appropriate cells in other tables in the Reset RIN template.

The Balancing Item was calculated by obtaining the total opex figure from previous RINs and deducting from it the opex in the table.
We have provided a reconciliation of the balancing items in tables 2.1.1, 2.1.2, 2.1.3, and 2.1.4 in the file *2.1 Expenditure Summary Tables Reconciliation_2014_05_27 .xlsx* which is provided as an attachment.

Use of estimated information

Forecast data is considered to be estimated information.

Reliability of information

Data sourced from previous audited RINs for the respective years is considered to be reliable. Data sourced from other tables within the Reset RIN template may be based on assumptions and estimates and should be used with caution for benchmarking or decision making purposes.

2.1.5 Dual function assets capex

Compliance with requirements of the notice

As Essential Energy has no dual function assets, there is no data inputted for this table.

2.1.6 Dual function assets opex by category

Compliance with requirements of the notice

As Essential Energy has no dual function assets, there is no data inputted for this table.

Worksheet 2.2 – Repex

2.2.1 Cost metrics by asset category

Compliance with requirements of the notice

The information provided is based on all assets owned by Essential Energy as well as privately owned assets where they are managed and maintained by Essential Energy.
Data has then been filtered to only include assets that are not a dedicated street light asset, and that are “in service”.

Source of information

Data has been sourced from the following:

- PeopleSoft Financial System
- Works, Assets, Solutions and People Database (WASP)
- Smallworld Geospatial Information System (GIS)
- Totalsafe Safety and Incident System (Totalsafe)
- Electricity Network Incident Failure Database (ENI)
- Electricity Networks Association Annual Pole Failure Reporting

Methodology and Assumptions

All Expenditure Categories

Historical expenditure has been sourced from previous annual RINs wherever relevant categories existed. Where appropriate categories did not exist we have apportioned the high level amounts by a consistently applied algorithm based on the percentage split incorporated in the more detailed forecast expenditure. For example where only a total figure for all distribution line replacement work existed we have split the figure into the following sub categories; poles, pole-tops, conductors, services and switchgear based on the detailed forecast analysis. These amounts have then been broken down to individual asset type categories through a ratio model based on actual unit replacement numbers. Expenditure in both 2009 and 2010 are known to be understated in most categories due to a complete review of the financial systems undertaken by Essential Energy at the end of financial year 2010.

For this reason historical expenditure for individual asset types can seem confusing but at the asset group level it is logical.

Only work tasks that have been completed as capital expenditure have been included in any replacement numbers. Failure numbers are based entirely from those replacements that were located and replaced on the same day as operating expenditure.

Pole Reinforcing (Staking)

Historical replacements have been based on a count of all completed capitalised WASP work tasks (Pole - Reinstate). Data has been filtered to only include those poles that are NOT a dedicated street light asset.

As table 2.2.1 only refers to those tasks completed as capital work and the majority of pole reinforcing that has been completed to date has been done as operating expenditure, the table incorrectly assumes there has been little pole reinforcing before 2014. Total pole reinforcement numbers were approximately 800 per year and are set to increase from 2014 onwards.

Failures have been based on all known failures. WASP does not have a work task associated with failure of pole reinforcements due to the rare occurrence of these failures.

Pole Replacements

Data has been filtered to only include those poles that are NOT a dedicated street light asset.

Historical data has been based on a count of all completed capitalised WASP work tasks (Pole - Condemned - Replace, Pole - Concrete - Replace, Pole Steel/Tower - Replace).

All failure data has been filtered to only include those poles that are NOT street light columns.

Historical data from 2009 to 2012 is based on ENA pole failure reports. 2013 data is sourced from a recently developed 'Pole Failure's' database. Failures with unknown material or voltage have had values assigned based on the ratio of failures with known values from FY2013.

Poletop Replacements

Historical replacement data has been based on a count of all completed capitalised WASP work tasks (Crossarm - Replace).

Historical failure data has been based on a count of all completed Opex WASP work tasks (Crossarm - Replace) that were reported and completed on the same day.

Conductor – Cable Replaced

Historical data for cable/conductor replaced is based on reconductor construction plans entered into the Smallworld GIS. This data has then been filtered to remove all work completed under any AER driver other than replacement. The replaced conductor material is not recorded so the material represents the conductor installed (not what was pulled down). Historical replacement data is greatly affected by several reviews of the dominant driver allocated to each individual project. This created inconsistent historical data especially regarding underground replacement quantities and therefore specific unit rates during this period should not be relied on.

Historical failure data for overhead conductors is based on the following WASP work tasks; (Conductor - Replace Sleeves, Conductor - Replace Splice, Conductor - Install Sleeves, Conductor - Install Splice). Historical failure data for underground cables is based on the following WASP work tasks; (URD – Cable – Replace).

Services Replaced

Historical replacement data has been based on a count of all completed capitalised WASP work tasks (Service – Replace Service) and (Service - Programmed Replacement). 2014 financial year data is based on an annualised year to date count of the same work tasks.
Historical failure data has been based on a count of all completed Opex WASP work tasks (Crossarm - Replace) that were reported and completed on the same day. 2014 data is based on annualised year to date WASP work tasks.

Transformers Replaced

Historical replacement data for overhead transformers has been based on the count of completed capitalised WASP work tasks (Substation - Replace Tank). Replacement split regarding voltage, kVA, phasing and mounting type have then been apportioned based on the 2013 full year actuals.

Historical failures of overhead transformers are based on those (Substation – Replace Tank) WASP work tasks that were found and replaced on the same day by Opex.

Both historical and future replacement of enclosed transformers (ground/chamber and pad/kiosk) has been based on the Essential Energy investment case ESS31 – Enclosed Substation Refurbishment Program. Enclosed transformer historical failures have been sourced from the same investment case and future failures are based on an average of 2012 and 2013 data.

Switchgear Replaced

Historical replacement data has been based on a count of completed capitalised WASP work tasks (ABS - Replace), (Fuse – Replace Fuse), (Fuse – EDO Fuse Programmed Replacement), (Links - Replace) and (Protection Site – Replace).

Historical failure data has been based on a count of the above WASP work tasks that were reported and completed on the same day as operating expenditure.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

Historical expenditure, at an aggregate level, is considered to be reliable as it has been sourced from previous annual RINs. Apportionment of expenditure into the different categories requested by the AER is based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

Public Lighting

Compliance with requirements of the notice

The information below relates to Public Lighting Assets only and is in accordance with that definition as provided by the AER.

Source of information

Refer to Basis of Preparation for table 4.1.2.

Methodology and Assumptions

Expenditure

Asset Type	Included in Total
Luminaires	Sum of all material and labour costs for replacement work tasks excluding pole replacement costs as per calculation method described in basis of preparation for table 4.1.2
Brackets	This data is not captured in any database
Lamps	There are no dollars included in this section as lamps are not considered

	as REPEX
Poles	Sum of all pole replacement and inspection costs as per calculation method described in basis of preparation for table 4.1.2

Asset Replacements

Asset Type	Included in Totals
Luminaires	Sum of all routine replacement work task quantities identified by method described in basis of preparation for table 4.1.2
Brackets	This data is not captured in any database
Lamps	There are no volumes included in this section as lamps are not considered as REPEX
Poles	Sum of all replacement work task quantities identified by method described in basis of preparation for table 4.1.2

Asset Failures

Asset Type	Included in Totals
Luminaires	Sum of all non-routine replacement work task quantities identified by method described in basis of preparation for table 4.1.2
Brackets	This data is not captured in any database
Lamps	There are no volumes included in this section as lamps are not considered as REPEX
Poles	Sum of all replacement work task quantities identified by method described in basis of preparation for table 4.1.2

Use of estimated information

None noted

Reliability of information

While Essential Energy has provided its best estimate of the data, assumptions and estimates have been used to compile it. Caution should be used when using this for benchmarking or decision making purposes.

SCADA & Network Control Communications Network Assets

Compliance with requirements of the notice

The information below relates to SCADA & Network Control Communications Network Assets only and is in accordance with that definition as provided by the AER.

Source of information

Several systems and planning documents have been queried. These systems and documents are listed below along with the data sets obtained from those systems.

System	Data set
PeopleSoft	Historic Expenditure
Primavera	Capital project data
Service Manager	Historic Asset Replacements/Asset Failure
Diagnostic Software	Historic & current radio asset data
ROE device list	Historic & current IP asset data

Methodology and Assumptions

Expenditure

Historic

All capital spend has been has been sourced from the Regulatory accounts and apportioned into the different categories based on actual expenditure in PeopleSoft financials.

Projects to deliver other network infrastructure elements that have a communications component have not been reported in this section. These projects will be reported in other areas of the RIN spread sheet depending on the specific driver for the project.

Asset Replacements/Failures

Historic

<u>Asset Replacement</u>

Data is based on capital replacement programs to replace End of Life assets or equipment deemed not fit for purpose.

<u>Asset failure</u>

Assets included in this category are those that have been replaced due to unplanned failure. Incidents or faults that have been rectified by means other than an asset replacement have not been included in this section.

Use of estimated information

None noted

Reliability of information

Historical unit data sourced from systems and planning documents is considered to be reasonably reliable.

Disaggregated financial information is based on assumptions and estimates and caution should be used when using it for decision making or benchmarking purposes.

Zone substations

Compliance with requirements of the notice

The information below relates to Zone Substation assets only and is in accordance with that definition as provided by the AER.

Source of information

Data has been sourced from the following:

- Investment cases
- WASP database
- Internal spread sheets

Methodology and Assumptions

Asset Counts:

- PTX & Circuit Breaker (CB) data was sourced from Investment Case document for the years 2010/11 until 2018/19.
- Asset count information for 2008/09 & 2009/10 for PTXs and CBs was sourced from WASP asset data commissioning dates with an estimated installation ‘reason’ = Replacement (as distinct from Growth).
- Switchboard-mounted CB data was sourced from the Investment Case document for the years 2013/14 until 2018/19 and from WASP asset data prior to 2013/14, using a mixture of actual & estimated commissioning dates and an assessed installation ‘reason’ = Replacement. Each CB data record was first assessed (in the absence of a record attribute to indicate this), as to whether it was an indoor switchboard-housed unit or a stand-alone unit.
- Air-break switches/isolators/fuse etc. replacements for the years 2008/09 until 2012/13 were assessed from WASP commissioning dates in the same manner as CBs for this period.

Asset Failures:

- Asset failures were assessed from a review of internal spread sheets: ‘Transformer Failure Database MASTER’, ‘ZS Master Outage Incident Database’ and corrective maintenance tasks in WASP. Final figures for stand-alone CB failures were derived from the Zone Substation Circuit Breaker Replacement Investment Case document (Table 5).
- Switchboard-housed CBs are more difficult to assess – dates & quantities are approximate. Switch/Isolator failures for 2008/09 until 2012/13 were assessed from WASP corrective work task records, which are a poor source of information. Lack of documented causes/reasons for corrective maintenance, make it likely that many of these failures have not been picked up from this source.

Costs:

- PTX & CB data sourced from Investment Case document for the years 2010/11 until 2018/19.
- Switchboard data taken from the Investment Case document for the years 2013/14 until 2018/19. Costing data for 2008/09 & 2009/10 for PTXs and CBs was proportioned from the 2010/2011 figures.
- Switches were estimated based upon current cost estimating figures from the document ‘UnitCostingV1.06.xlsm’ which estimates install costs for 11/22kV units at approx. $26k, 33kV at approx. $33k, 66kV at approx.$39k and 132kV at approx. $51k.

Use of estimated information

Refer to methodology and assumptions sections above as well as investment case documents.

Reliability of information

Historical expenditure information, at a total level, has been sourced from the Regulatory accounts, and is considered reliable. However the splits into the different categories requested by the AER are based on assumptions and estimates and caution should be used when using for benchmarking or decision making purposes.

Customer Metering and Load Control, Easements, Land (System), S&W Accrual and other adjustments

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Data sourced from the Regulated Distribution System Capex Expenditure Report (RDSC) and excludes overheads.
- This report was used to reconcile back to the regulatory accounts figures for each respective year.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

2.2.2 Descriptor metrics

Compliance with requirements of the notice

The information provided is based on all assets owned by Essential Energy as well as privately owned assets where they are managed and maintained by Essential Energy.
Data has then been filtered to only include those assets that are “in service”.

Source of information

Data has been sourced from the following:

- Works, Assets, Solutions and People Database (WASP)
- Smallworld Geospatial Information System (GIS)
- Electricity Network Incident Failure Database (ENI)

Methodology and Assumptions

Total Poles by Feeder Type

Data has been filtered to only include those poles that are NOT a dedicated street light asset. Asset volumes have been sourced through the Smallworld GIS database.

Historical replacements have been based on a count of all completed capitalised WASP work tasks (Pole - Condemned - Replace, Pole - Concrete - Replace, Pole Steel/Tower - Replace), then mapped to the GIS information.

All data has then been mapped by individual asset number against the geospatial information held in Smallworld to align replacement data to the following feeder type categories based on proximity to particular conductors:

- Long Rural
- Short Rural
- Urban
- Unknown

Overhead Conductors by Feeder Type

Only those overhead conductors designated as part of a feeder (both HV and LV) have been included in the total circuit length volume. Overhead service cable has been deliberately excluded. All data has been sourced from GIS queries using the following logic; HV feeders based on reliability categorisation, LV feeders based on their parent HV feeder, and transmission and unknowns distributed by ratio across the three categories.

Historical data for conductor replaced is based on reconductor construction plans entered into the Smallworld GIS. This data has then been filtered to remove all work completed under any AER driver other than replacement. Data is more accurate from 2010 onwards as can be seen from the unusually low volumes in 2009.

Overhead Conductors by Material Type

All overhead conductor circuit length has been included in the total volumes for each material including overhead low voltage services. LV service total has been estimated based on 602,593 services at approximately 30 metres in length each. All data has been sourced from the GIS.

Historical data for cable/conductor replaced is based on reconductor construction plans entered into the Smallworld GIS. This data has then been filtered to remove all work completed under any AER driver other than replacement. Although the vast majority of conductor replaced is suspected to have been either small hard drawn copper, old galvanized steel or poor condition ACSR conductor, the replaced conductor material is not recorded. Therefore the material recorded represents the conductor installed (not what was pulled down). Data is more accurate from 2010 onwards as can be seen from the unusually low volumes in 2009.

Underground Cable by Feeder Type

Only underground cables designated as part of a feeder (both HV and LV) have been included in the total circuit length volume. Underground service cable has been deliberately excluded as it is generally regarded as privately owned and maintained by the customer. All data has been sourced from GIS queries using the following logic; HV feeders based on reliability categorisation, LV feeders based on their parent HV feeder, and transmission and unknowns distributed by ratio across the three categories.

Historical data for cable replaced is based on reconductor construction plans entered into the Smallworld GIS. This data has then been filtered to remove all work completed under any AER driver other than replacement. Data is more accurate from 2010 onwards as can be seen from the unusually low data in 2009.

Transformers by Total MVA

Total MVA of Essential Energy owned distribution transformers was sourced from WASP.

Historical replacement MVA data for overhead transformers has been based on the count of completed capitalised WASP work tasks (Substation - Replace Tank). Due to the data structure in WASP, the kVA captured is the transformer that has been installed, not the unit that was removed.

Both historical and future replacement of enclosed transformers (ground/chamber and pad/kiosk) has been based on the Essential Energy investment case ESS31 – Enclosed Substation Refurbishment Program.

As no accurate information is available for disposed MVA it is assumed that the replacement MVA will suffice.

PTX's

- A WASP Asset Register PTX data dump dated 5/2/2014 was extracted.
- 'Total MVA Replaced' calculated by multiplying average MVA of in-service PTX's (15.463 MVA) by the corresponding yearly head-count of replaced PTX's.
- 'Total MVA Disposed of' calculated by multiplying average MVA of in-service PTX's (15.463 MVA) by the corresponding yearly head-count of PTX's in WASP at the date where the asset's 'Service Status' was changed to 'Scrapped'.
- 'Asset Volumes Currently in Commission' – this figure is simply a summation of the 'Maximum Rating (MVA)' for all PTX's in WASP with a current Service Status of 'In Service'.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

While Essential Energy have provided their best estimate of the data, the information provided is based on assumptions and estimates and caution should be used when using it for benchmarking or decision making purposes.

Worksheet 2.3 – Augex Project Data

2.3.1 Augex asset data – Subtransmission substations, Switching stations and Zone substations

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

Data has been sourced from Primavera, Essential Energy's project management system.

Methodology and Assumptions

To extract the data, the following assumptions have been made:

- Transformer Units added. Assumes if you replace one transformer with two you have added 1 unit.
- Transformer MVA added. Assumes if you replace 10MVA with a 30MVA transformer you have added 20MVA.
- Switchgear Units added. Assumes if you replace one circuit breaker (CB) with another one then you have not added anything. Also assumes that replacing a CB and CT with a dead tank counts as a one for one replacement. Also assumes only ABS CT VT and CB are the primary plant. No Earth switches. No FI gear. No fault thrower. No Surge Arrestors. Analysis has been performed on single line diagrams for units but Primavera dollars for total expenditure are based on manufacturer's names.
- Installation hours are inclusive of all hours on the project including design, and project management.
- Civil works is inclusive of the major contract (and other contracts). This could not be separated out.
- Total direct expenditure and major contract expenditure equates to the total direct costs of the project.

Use of estimated information

- Essential Energy has used estimated information for three projects as the financial data was pre 2008 when Essential Energy's systems were not in place and large financial movements could not be reconciled at detail levels. The three projects are (MCV), (RGL), and (BBS).
- Non material projects estimated MVA added and switchgear added. Historical data on what was replaced does not exist. The calculation used is based on known projects.

Reliability of information

Most of the information provided in this table is considered reliable. However, reliable information does not exist for some projects, as indicated by the colour coding used, and caution should be used when using this information for decision making or benchmarking purposes.

2.3.2 Augex asset data – Subtransmission lines

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

Data has been sourced from Primavera, Essential Energy's project management system.

Methodology and Assumptions

To extract the data, the following assumptions have been made:

- Installation hours are inclusive of all hours on the project including design, and project management.
- Civil works is inclusive of the major contract (and other contracts). This could not be separated out.
- Total direct expenditure and major contract expenditure equates to the total direct costs of the project.

Use of estimated information

- Four projects were not 100% complete and could have some minor transactions still to occur. (896:MLN)(84Y)(89H)(97R)
- Non material projects have been estimated. Extrapolated calculations are based on known projects.

Reliability of information

Most of the information provided in this table is considered reliable. However, reliable information does not exist for some projects, and caution should be used when using this information for decision making or benchmarking purposes.

2.3.3 Augex asset data – HV/LV Feeders and Distribution substations

2.3.3.1 Descriptor metrics

Feeder Augmentation

Compliance with requirements of the notice

The information provided reports a breakdown of circuit kilometres of both high voltage and low voltage feeders added and augmented in the current period.

Source of information

The data for the current period was provided by the GIS team and sourced from Smallworld. This data was provided for table 6.1 of the DNSP economic benchmarking RIN.

Methodology and Assumptions

Current Period: Circuit kilometres added.

The data provided shows yearly cumulative circuit lengths for the various distribution voltages used. This information was sorted into a high voltage and low voltage group for both underground and overhead circuits. The annual increases for each class were then calculated by subtracting each year from the previous year. Where the data appeared suspect, an estimate was made.

The figures extracted from the GIS for the LV Feeder Augmentation Overhead Lines (Line Added) are not reliable as they show an unrealistic variation from year to year including some significant negative swings.

Current Period: Circuit kilometres upgraded.

This data was provided from the Planning Database. A report was run for all works completed in each year and the results filtered for the following categories:

- HV OH Lines miscellaneous works
- HV OH Lines reconductoring
- HV Underground recabling
- HV Underground Mains miscellaneous works
- LV reconductoring/relocation
- LV recabling

Results were then grouped into the required classes. Where data was suspect or missing, predominantly in the earlier years, an estimate was made.

It is assumed that 33kV lines are substransmission lines.

Use of estimated information

Essential Energy has used estimated information for:

- HV Underground Feeder added 2008/09
- LV Overhead Lines 2008-2010
- LV Underground Lines 2008-2010
- HV Overhead Feeder upgraded 2008/09
- HV Underground Feeder upgraded 2008/09
- LV Overhead Feeder upgraded 2008/09
- LV Underground Feeder upgraded 2008/09

An estimate was used for these figures as there was incomplete or no data available for the years in question.

The estimate for line added was derived by taking the average of the WASP figures of line added (green) in the years of reasonable data and using it for 08/09.

The estimate for line augmented was derived by taking the reasonable data from the Planning Database (green) and projecting backwards as a ratio of 08/09 budget against 09/10 budget.

Reliability of information

Historical information is a combination of both actuals and best estimates. Estimated information should be used with caution when using for benchmarking or decision making purposes.

Forecast information is based on estimates and assumptions and caution should be used when using for it for decision making purposes.

2.3.3.1 Descriptor metrics

Substation Augmentation

Compliance with requirements of the notice

The information provided reports a breakdown of substations that have been added or augmented in the current period.

The information is divided into the following classes:

- Pole Mounted Substations
- Ground Mounted Substations
- Indoor Substations

Source of information

The data for the current period was sourced by generating an 'Equipment Report' from the Planning Database for the years 2008/09 to 2013/14.

Methodology and Assumptions

Distribution Substations Added:

The data for the current period was sourced by filtering the Equipment Report for each year for 'Distribution Transformers-New', and then filtering those results by equipment type to obtain the three classes required:

1. Pole Mounted
2. Ground Mounted
3. Indoor

This provided reasonable data for the later years (2010/11 to 2013/14).

The data for the earlier years in the Planning Database was incomplete or not available.

Use of estimated information

Essential Energy has used estimated information for:

- Distribution Substations added, Pole Mounted - 2008/09 – 2010/11
- Distribution Substations added, Ground Mounted – 2008/09 – 2009/10
- Distribution Substations added, Indoor – 2008/09
- Distribution Substations augmented, Pole Mount – 2008/09 – 2010/11
- Distribution Substations augmented, Ground Mount – 2008/09 – 2010/11
- Distribution Substations augmented, Indoor – 2008/09

An estimate was used for these figures as there was incomplete or no data available for the years in question.

The methodology used to provide an estimate was to source the numbers of total transformers issued by logistics for all years (from WASP). For the years where no data existed in the Planning Database for numbers added or augmented, Essential Energy applied a ratio based on the total number of transformers issued in those years i.e. the number estimated for year 2010/11 was based on the real data for 2011/12, varied by the ratio of total transformers issued in those two years. 2009/10 was subsequently based on the figure for 2010/11, varied by the ratio of total transformers issued in those two years.

Reliability of information

Historical information is a combination of both actuals and best estimates. Estimated information should be used with caution when using for benchmarking or decision making purposes.

Forecast information is based on estimates and assumptions and caution should be used when using for it for decision making purposes.

2.3.3.2 Cost metrics

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

Historical expenditure

- Information was sourced from the ‘summary of direct costs’ tab in the Capex master split workpaper. A PeopleSoft report is run each month to split out Capex between Augex and Repex by various asset categories. This report is used to report figures in the regulatory accounts.
- Regulatory accounts’ asset categories are consistently grouped based on model parameters.
- Mapping was performed to comply with the requirements of the RIN tables. Refer to ‘Mapping Augex’ tab in the Capex master split workpaper. Mapping has been used to link data from the ‘summary of direct costs’ tab to the RIN tables based on subject matter expert’s judgements.

Reliability of information

Most historical data is based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

2.3.4 Augex data – Total expenditure

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Figures in table 2.3.3.2 have been used to populate table 2.3.4 for both historical and forecast data. Where additional Augex asset categories have been added in line with other elements (e.g. land and subtransmission) in the ‘summary of direct costs’ tab of the Capex master split worpaper.
- The other assets line is not a balancing item but picks up individual asset categories from the ‘summary of direct costs’ tab in the Capex master split workpaper.
- The total of all line items reconciles back to the ‘summary of direct costs’ tab which reconciles back to the regulatory accounts for historic expenditure. The same basis applies to forecast data which reconciles to ROMO.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 2.4 – Augex Model

2.4.1 Augex model inputs - asset status - sub transmission lines

Compliance with requirements of the notice

Essential Energy has, in accordance with the requirements of the Regulatory Information Notice completed table 2.4.1 and the basis of preparation for the fore mentioned table 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 table 2.4.1 was sourced from the following:

- HV Feeder categorisation (urban, short rural, long rural) – based on maximum yearly demand (SCADA was used where available or assumptions were made) and feeder length (Smallworld)
- Sincal – Specifically for table 2.4.1 data was sourced on;
  - Network loading
- CE Subtransmission Feeder Ratings Version U Draft.xlsx – Specifically for table 2.4.1 data was sourced on;
  - feeder section lengths
  - feeder section ratings
  - underground and overhead lengths
  - feeder voltage
  - line ID
- Operational Manual: Standard Overhead Conductor: Current Rating Guide CEOM7011– Specifically for table 2.4.1 data was sourced on;
  - Conductor and Cable ratings

Line ID, Line voltage, 2012-13 and 2008-09 Route line length as at 30 June of year
The above parameters have been sourced using Essential Energy's most reliable data source which is a spread sheet held by Planning named CE Subtransmission Feeder Ratings XXX.xlsx

Methodology and Assumptions

Primary type of area supplied by line
The primary type of area supplied by each HV feeder was determined based on maximum yearly demand and feeder length. Zone substation primary type of area was determined based on the number of feeders supplied in each category, where there were even numbers of feeders supplied under a number of categories the least dense category was chosen, i.e. in order from long rural to urban. Subtransmission feeder primary type of area was chosen based on the terminating zone substation – note that where a terminating substation is a tee, a surrogate zone substation was chosen from, the next zone substation, the originating zone substation or a nearby zone substation.

Originating substation and terminating substations
Originating substation and terminating substations have been completed based on the load flow under normal conditions for a particular line in question.
2012-13 and 2008-09 "Maximum demand (weather corrected at 50% PoE)"

In general, maximum demand data for subtransmission lines is not recorded, therefore for the purpose of the Reset RIN maximum demand data has been calculated in Sincal, using load flow calculations. These calculations are based on raw adjusted non-diversified zone substation peak loads for the year in question under system normal conditions. Maximum demand for subtransmission feeders have not been calculated under any N-1 conditions, however augmentation can often be caused by the requirement to achieve N-1 functionality.

Weather corrected data at 50% PoE is not available for subtransmission lines, nor is it practical or accurate to apply generalised assumptions in order to weather correct non-corrected data or provide probability of exceedence levels. As a result, Essential Energy has used raw actual data as the best estimate of weather corrected 50% PoE given the timeframes and resource available.

For planning purposes this is the demand that would be used as a first pass to evaluate the likelihood of reaching a constraint on a subtransmission feeder under normal conditions. For planning purposes the same method would also be used to evaluate network demands under N-1 conditions where appropriate. Once a potential constraint has been identified a more thorough review of actual demands would be undertaken taking into account the likely diversified loads of the connected zone substations.

2012-13 and 2008-09 Line rating Thermal

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

- 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)

The derivation of ratings for subtransmission feeders is based on the above information for the year in question and;

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

It should be noted that the ratings for a particular feeder in a particular year may be different to those observed in a later year without any augmentation expenditure due to the increase in knowledge over the period in question. For example, the survey of a line which finds low hanging spans or spans of a different conductor type to those previously recorded.

The ratings method defined above is that used for determining augmentation of the network with the exception of voltage constraints.

2012-13 and 2008-09 Line rating N-1 emergency

In Essential Energy's network each line ID refers to an individual subtransmission line, as the definition of N-1 is a single contingency emergency condition (i.e. the outage of one line), it is not possible for an individual subtransmission line to have an N-1 rating.

It should also be noted that the N-1 for subtransmission feeders in Essential Energy's network is not generally a simple case of two subtransmission feeders feeding a particular zone substation or zone substation area, rather N-1 for an area generally consists of many subtransmission feeders in series and in parallel with multiple feeder ratings and load flowing through multiple zone substation buses and tee sections.

Use of estimated information

All loading data in table 2.4.1 can be considered as estimates as it is based on engineering data and a variety of assumptions.

Reliability of information

As stated within the line thermal rating section above, the ratings for a subtransmission line in a particular year may be different to those observed in a later year without any augmentation expenditure. This is simply due to the increase in knowledge of line parameters over the period in question. For example, a survey of a subtransmission line may find low hanging spans or spans of a different conductor type to those previously recorded. Therefore, due to the change in ratings from knowledge gained and not augmentation expenditure, the change in ratings over the period of interest should not be used as a basis for calculating capacity added to the subtransmission network.

It should also be noted that some subtransmission lines may not be present within table 2.4.1 due to old model data. This again stresses the importance that such differential calculations over the period of interest should not be used to calculate capacity/line length added to the network.

As per the use of estimated information section above, Essential Energy have provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes. All other information provided is considered to be reliable.

2.4.2 Augex model inputs - asset status - high voltage feeders

Compliance with requirements of the notice

Essential Energy has, in accordance with the requirements of the Regulatory Information Notice completed table 2.4.2 and the basis of preparation for the fore mentioned table 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 table 2.4.2 was sourced from the following:

- Smallworld - Specifically for table 2.4.2 data was sourced on;
  - feeder voltage
  - feeder originating substation
  - feeder route line lengths
  - feeder conductor exiting zone substation

- Sincal - Specifically for table 2.4.2 data was sourced on;
  - feeder conductor exiting zone substation
  - conductor current ratings

- TrendScada - Specifically for table 2.4.2 data was sourced on;
  - feeder maximum demands

- Operational Manual: Standard Overhead Conductor: Current Rating Guide CEOM7011 - Specifically for table 2.4.2 data was sourced on;
  - Conductor and Cable ratings

Methodology and Assumptions

Essential Energy has used the following methodologies and assumptions in determining the high voltage feeder information requested.

For the distribution network, relatively accurate information is held on feeder sections including:

- Region
- Area
- Feeder Name
- Originating Substation
- Operating Voltage (kV)
- Feeder Length (km)

However, some sites do not have records related to the conductor type and no HV feeders include a design temperature.

Derivation of Feeder ID, Voltage Level, Originating Substation, Route Line Lengths, High Voltage Feeder Type

Every month a report is generated for assessing the reliability of all of Essential Energy's feeders. These reports include the information requested regarding Feeder ID, voltage level, originating substation, route line lengths, and feeder type.
The data is originally extracted from Smallworld at the end of each month, providing a historical record of Essential Energy's feeders.

The route line length for each feeder is a combination of all the feeder segments on that section of network, combining underground and overhead segments. The voltage level is based on the voltage exiting the zone substation, so any change in voltage through transformers are not visible, though the line length has been accounted for. This includes a large portion of the SWER segments that connect to the three phase feeder through an isolation transformer.

There may be inconsistencies between data sources based on the date data was extracted from Smallworld, as well as the possibility of network segments without a defined feeder name within the linked data. An extract per feeder will not include these segments, though an extract based on conductor voltages will.

Assumptions;

- The data obtained by the reliability team is an accurate representation of the feeders connected to the network.
- The feeder type calculated by the reliability team was based on accurate demand data and feeder length.

Derivation of Feeder Ratings

The thermal rating for all available HV feeders was taken as the rating of the first conductor out of the substation based on the conductor type and a 50 degree Celsius rating. Where the conductor type was not available, the average known utilisation for each feeder category was calculated and applied to the feeders with unknown ratings. The average utilisation only included known feeder loads that were below their respective feeder rating.

The overhead conductor ratings used conductor tables from Sincal with a 50 degree Celsius rating. The Sincal conductor tables use the ESAA Publication D(b)5-1988 for ratings, which includes variables for wind speed, ambient temperature and designed temperature. The underground conductor ratings were based on manufacturers' datasheets.

The data provided here is not a true reflection of actual feeder ratings used in augmentation planning and/or operation of the distribution network as many feeders may be designed above a 50 degree Celsius rating, nor is the rating particularly relevant to the probability of augmentation as network planners will more often need to augment the distribution network in response to voltage constraints which occur well before the thermal limit of the feeder is reached. Alternative ratings based on voltage constraints are most commonly identified through customer reports of low voltage. The feeder is then analysed using load flow analysis to determine the extent of the issue. The non-linear distribution of the loads connected to each feeder and the different conductor sizes that are installed on each feeder make defining a single feeder rating impossible. The unique properties of each feeder and the scale of the electricity distribution network limits the ability to grade each feeder based on their voltage limitations.

Assumptions;

- 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.
- The operational rating is to be no more than the thermal rating, and as this information is not recorded, the thermal rating was seen as equivalent to the operational rating.
- As there is an absence of historical feeder information, the feeder ratings from 2009 are the same conductors as those given in 2013.

Derivation of Maximum Demands

Essential Energy does not currently store historical weather corrected maximum demands at 50% PoE, so all of the provided data uses raw adjusted maximum values. The data is obtained from TrendScada where available, which reads current and voltage transformer information and stores the results in the SCADA system. Where this is not available, other measurement devices such as Maximum Demand Indicators are used.

The data obtained has filtered out large switching peaks, but any block loads that were connected for a significant period of time were left as part of the normal load. Switching peaks are not included in the maximum demands used for normal planning, and block loads are assessed on a case-by-case basis to confirm relevance with future feeder loads.

Weather corrected data at 10% or 50% PoE is not available for high voltage feeders, nor is it practical or accurate to apply generalised assumptions in order to weather correct non-corrected data or probability of exceedence levels. As a result, Essential Energy has used raw actual data as the best estimate of weather corrected 10% and 50% PoE given the timeframes and resource available.

Where either MVA or MW was not available, the power factor of known feeder maximum demands was used to calculate the absent data. Where neither demand data was available, an average utilisation of known feeders based on the feeder category and conductor type was used to calculate the expected maximum demands. The average utilisation only included known feeder loads that were below their respective feeder rating.

The calculated maximum demand data was compared against the network simulation models within Sincal, to ensure the data was a reasonable representation of the network.

There are a number of sites that indicate an utilisation of greater than one, indicating the feeder has a higher maximum demand than the total feeder thermal rating. There are a number of factors that may contribute to higher than expected utilisation, these include;

- The assumption that all feeders have been designed to a 50 degree rating. A conductor installed for a 65 degree rating has a significantly higher current rating, in some cases over twice the 50 degree rating.
- The possibility of incorrect feeder conductor data.
- The possibility of incorrect demand data.

Feeders that local planners believe may be over utilization are analysed on a case by case basis, however the results may not be passed on to the geographical information system at the time of data extraction.

Assumptions;

- The switching peaks that were removed were not representative of the actual load present on the feeders.
- The block loads that were connected for extended periods of time provide a true representation of normal feeder loads for that year.

Use of estimated information

All demand and rating data in table 2.4.2 can be considered as estimates as it is based on engineering data and a variety of assumptions.

Reliability of information

As per the use of estimated information section above, Essential Energy have provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

2.4.3 Augex model inputs - asset status - subtransmission substations, subtransmission switching stations, and zone substations

Compliance with requirements of the notice

Essential Energy has, in accordance with the requirements of the Regulatory Information Notice completed table 2.4.3 and the basis of preparation for the fore mentioned table 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 table 2.4.3 was sourced from the following:

- Transformer Management & Contingency MASTER compare 2008-2014 SC.xls – Specifically for table 2.4.3 data was sourced on;
    - Site Name
    - Site Voltages
    - Transformer MVA ratings
    - Number of transformers
    - Installation date
- Table 2.4.2 of Essential Energy's economic RIN - Specifically for table 2.4.3 data was sourced on;
    - Type of area supplied
- Table 5.4.1 of Essential Energy's economic RIN - Specifically for table 2.4.3 data was sourced on;
    - Site Type
    - Substation MVA ratings
    - Maximum Demands
    - Expected future demands

Some sites were split into multiple records to provide a more accurate view on maximum demands and N-1 emergency ratings at different voltage levels. Recently constructed sites where no load was connected until after 30 June 2013 were also included to provide the expected growth for that site.

Methodology and Assumptions

Derivation of ratings for Substation Sites

To calculate the ONAN transformer rating, all the ONAN cooling ratings were added together. The in service rating included any additional capacity gains through the use of forced air and forced oil if fitted, resulting in the maximum transformer nameplate rating.

The transformer normal cyclic rating uses the maximum transformer nameplate rating multiplied by 1.1 as defined by the "Subtransmission and Distribution Network Planning Criteria & Guidelines" (CEOP8003) policy document as the rating the transformer can sustain on a continuous cyclic basis for the life of the asset. The rating of 110% was used as it allows a maximum peak daily loading regardless of the season.

The substation normal cyclic rating was obtained from table 5.4.1, derived from the total demand the substation is capable of sustaining on a continuous normal cyclic basis. Refer to the basis of preparation for table 5.4.1 for the methodology.

The N-1 rating uses the total substation in service nameplate ratings, minus the largest transformer, multiplied by 1.2 as defined by the “Subtransmission and Distribution Network Planning Criteria & Guidelines” (CEOP8003) policy document as the cyclic rating the transformer can sustain for a short period of time. The rating of 120% was used as it allows a maximum peak daily loading regardless of the season. There is a 140% rating listed in the policy for very short durations however this is subject to constant monitoring of the oil and winding temperatures and therefore not always possible. The 120% rating offers a more conservative overload rating that can confidently be performed at the majority of sites under emergency conditions.

Substation augmentation is required when the forecast growth in a supplied area is in excess of the capability of the substations, as defined in the CEOP8003 policy document. Substations are not given alternative ratings for use in the planning and operation of the electricity network.

Assumptions;

- Refer to the basis of preparation for table 5.4.1 for the assumptions made regarding substation normal cyclic rating.
- All transformers with an AF rating have operational fans.
- The transformer rating at minimum meets the minimum requirement of the nameplate rating.
- The transformer normal cyclic rating does not include the extra capacity where tertiary windings are present but not utilised.

Derivation of Primary Type of Area Supplied

For Zone Substations, the feeders that are supplied from the substation have a classification, so the most common classification was given to the Zone Substation. Where there were an equal number of multiple classifications, the lowest density classification was given. For example, a site with two Urban and two Short Rural feeders was given a Short Rural classification.

For Subtransmission Substations and Subtransmission Switching Stations the most common Zone Substation classification of those supplied were applied to the site. Where equal numbers of multiple classifications were present, the lower density classification was given. For example, a site supplying two Urban Zone Substations and two Short Rural Zone Substations was classed as Short Rural.

Assumptions;

- The data obtained by the reliability team is an accurate representation of the feeders connected to the network.
- The feeder type calculated by the reliability team was based on accurate demand data and feeder length.

Derivation of Maximum Demands and Growth

The maximum demand data was obtained from table 5.4.1. Refer to the basis of preparation for table 5.4.1 for the methodology. Where no data was available from table 5.4.1, the historical load was obtained from TrendScada. This data is not weather corrected at 50% PoE.

Switching peaks are not included in the maximum demands used for normal planning, and block loads are assessed on a case-by-case basis to confirm relevance with future feeder loads. An average growth per year was calculated between the expected demand and the measured 2012/13 demand. The difference in maximum demand per year was divided by the 2012/13 demand to obtain a percentage change, and then multiplied by 100 to suit the table requirements. A value of 3.45 indicates a 3.45% yearly increase in demand from the 2012/13 value.

Weather corrected data at 10% or 50% PoE is not available for Substations, nor is it practical or accurate to apply generalised assumptions in order to weather correct non-corrected data or provide probability of exceedence levels. As a result, Essential Energy has used raw actual data as the best estimate of weather corrected 10% and 50% PoE given the timeframes and resource available.
Assumptions;

- Refer to the basis of preparation for table 5.4.1 for the assumptions made regarding maximum demands.

Use of estimated information

All weather corrected demand data in table 2.4.3 can be considered as estimated based on measured or engineering data and a variety of assumptions.

Reliability of information

As per the use of estimated information section above, Essential Energy have provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

2.4.4 Augex model inputs - asset status - distribution substations

Compliance with requirements of the notice

Essential Energy has, in accordance with the requirements of the Regulatory Information Notice completed table 2.4.3 and the basis of preparation for the fore mentioned table 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 table 2.4.4 was sourced from the following:

- Feeder categorisation (urban, short rural, long rural) – based on maximum yearly demand (SCADA was used where available or assumptions were made) and feeder length (Smallworld)
- Distribution substation construction type (Smallworld)
- Total distribution substation numbers and sizes (WASP)
- Distribution substation demands - Maximum Demand Indicator readings (WASP)

Methodology and Assumptions

Maximum Demand Data

Essential Energy has collected maximum demands across a number of distribution substations in an ad-hoc manner over a number of years in an attempt to better understand the loading on particular distribution substations at a particular point in time. This data is the basis for the utilisation profile of Essential Energy's distribution substations. Maximum demand indicators provide maximum demands on 15 minute averages, however no further correction for abnormal conditions is provided.

For normal planning purposes this is the maximum demand that would be used to determine a thermally overloaded distribution transformer, however a distribution transformer may also be replaced for augmentation based on voltage, i.e. where the voltage drop through the transformer is a significant contributor to voltage issues or where replacement of the transformer is the least cost solution to supply an appropriate voltage level.

It is not reasonable to perform weather correction against loads with minimal diversity. As a result, no weather correction has been undertaken on distribution substation loads.

Rating Data
Individual and aggregate ratings for substations have been determined based on the installed capacity of distribution substations (in WASP) multiplied by the allowable normal cyclic ratings as defined in Essential Energy policy CEOP8003 of 150%. WASP data is largely based on nameplate ratings with some minor adjustments. These ratings are as used for normal planning purposes (with the exception of voltage based augmentation).

Distribution Substation Categorisation
Essential Energy has attempted to establish the relationship between asset utilisation and feeder type (urban, short rural, long rural), distribution substation construction (ground mount or overhead) and size.

Figure 1 shows the attempted correlation between the feeder type the distribution substation is attached to and asset utilisation.

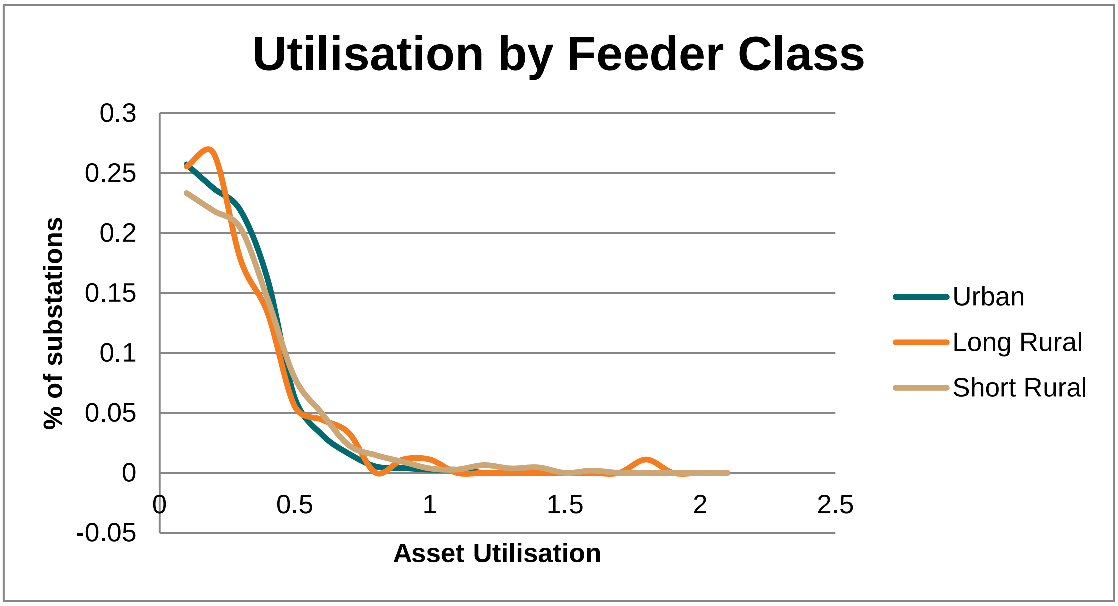


Figure 1 - Utilisation by Feeder Class

Based on the following sample size;

Table 1 - Utilisation by Feeder Class

	Number of Substations
Urban	750
Long Rural	90
Short Rural	1084

The variations seen in Figure 1 are most likely due to the small sample size of the points in question; hence it is not appropriate to break the data down to this level.

Figure 2 shows the attempted correlation between the distribution substation construction type and asset utilisation.

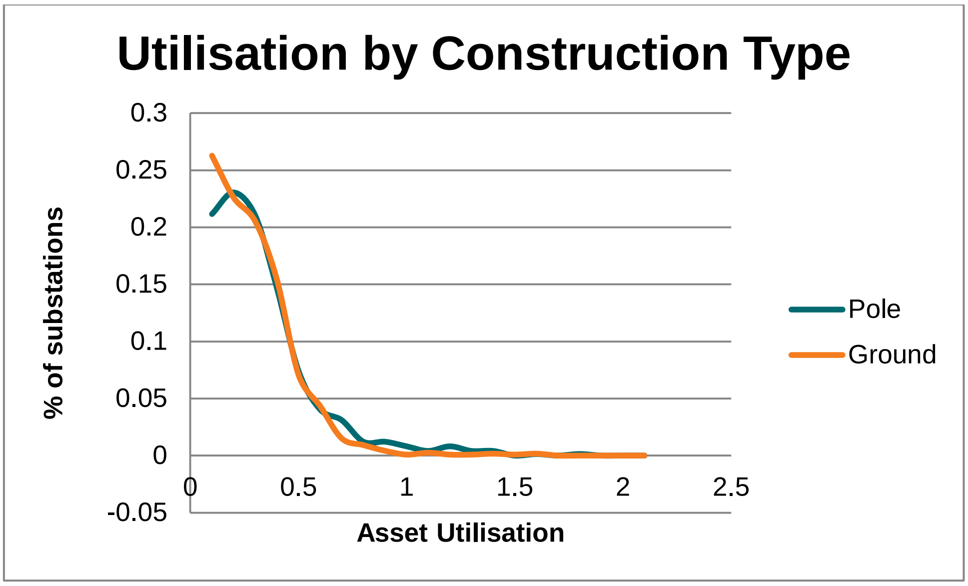


Figure 2 - Utilisation by Construction Type

Based on the following sample size;

Table 2 - Utilisation by Construction Type

	Number of substations
Pole	742
Ground	1199

The variations seen in Figure 2 are considered reasonable and will be used further.

Essential Energy utilisation over time

Essential Energy has attempted to compare the asset utilisation of distribution substations between 2009 and 2013 shown in Figure 3;

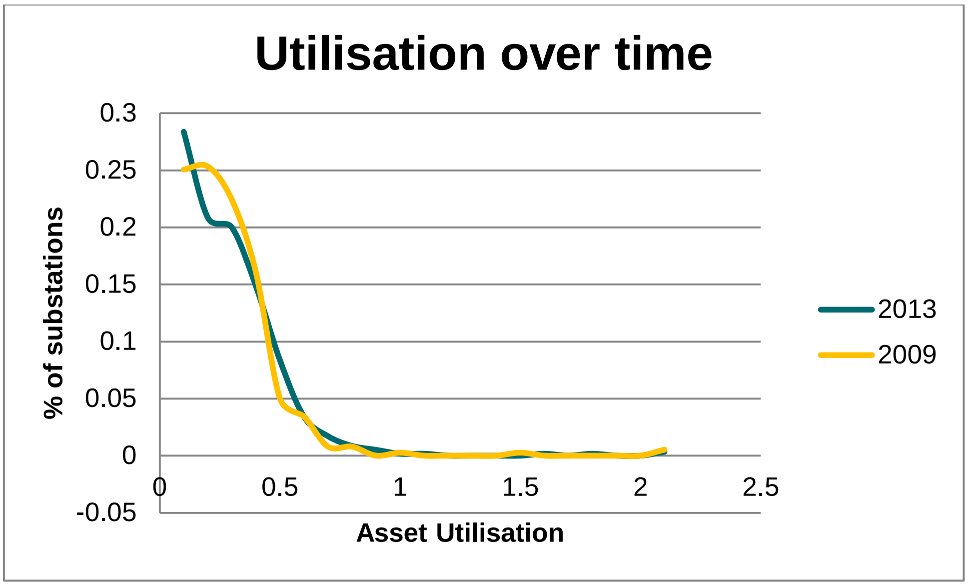


Figure 3 - Utilisation over time

Using the following sample size;

Table 3 - Utilisation over time

Year	Number of substations
2013	585
2009	379

The sample size in question is a significant amount and should therefore provide a reasonable indicator of the change in utilisation between 2009 and 2013. The variations seen in Figure 3 - Utilisation over timeFigure 3 are considered reasonable and will be used further.

Use of estimated information

Essential Energy's recorded demand information on distribution substations is a true indication of demand for a particular substation at a particular point in time; however this data was not collected in order to provide a statistically significant sample, nor were the samples purely random in nature. The use of such data to provide an average utilisation can therefore be considered as estimated data.

Reliability of information

As per the use of estimated information section above, Essential Energy have provided their best estimate of the data. The information provided is considered to be unreliable as it is not a statistically significant sample, therefore caution should be used taken when using it for decision making or benchmarking purposes.

It should be noted that the gathering of this information would require an extensive lead time and the installation of substantial quantities of metering devices. If the AER requires more accurate data in the future then expenses will need to be incurred to source this data and the AER's requirement will need to allow for the appropriate lead times (which in the case of metered data, the time required for normal program development and delivery plus an additional 12 months to gather the appropriate data).

2.4.5 Augex model inputs - network segment data

Compliance with requirements of the notice

All network segments have been classified based on their augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments. Hence, network augmentation projects only add capacity to the network segment requiring augmentation not multiple network segments, this ensures no double counting in estimates.

Subtransmission lines

Definition of Network Segment

Within Essential Energy's network, subtransmission lines are bounded by subtransmission substations and/or zone substations, i.e. zone substations are connected to subtransmission substations and/or zone substations via subtransmission lines. Essential Energy owns and operates subtransmission lines at 220kV, 132kV, 110kV, 66kV, 33kV. Note that Essential Energy owns and operates both subtransmission and distribution lines at 33kV. Subtransmission lines have not been bundled with other network segments (i.e. subtransmission substations and/or zone substations) due to its augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments. The subtransmission line asset class can be further broken down into underground and overhead types but due to the limited number of past projects from 2009-2014 for underground subtransmission lines, the asset class was considered as a whole.

Calculation of Network Segment Parameters

Within this section, details behind the calculation of subtransmission line segment parameters are presented and discussed. Note that the cost variance between augmenting overhead and underground subtransmission lines varies considerably but due to a few underground subtransmission augmentation projects over the 2008/09 – 2013/14 period, single subtransmission line parameters have been calculated to represent both underground and overhead for the periods of interest.

Data sources

To develop subtransmission line planning parameters, Essential Energy first sourced data direct from other tables submitted within the Reset RIN document, which includes:

- Per unit rate for subtransmission lines - total expenditure linked to completed projects was sourced directly from Table 2.3.2 – 'Augex asset data - subtransmission lines'. Total expenditure with reference to Table 2.3.2 includes:
    - Total Direct
    - Major contracts - non related party
    - Land and easements
- Table 2.4.1 - Augex model inputs - asset status - sub transmission lines
    - 2008/2009 and 2012/2013 Thermal Rating
    - 2008/2009 Maximum demand (MVA)

Additional data was sourced directly from the following Essential Energy systems:

- ProjectWise (Archived Drawings and Project Reports)
    - Existing Network Configuration
    - Present Network Configuration

- ENMAC
    - Present Network Configuration

Methodology

Essential Energy has used the following methodologies and assumptions in determining the network parameters for subtransmission lines:

1. Based on completed subtransmission line augmentation projects, pre and post line thermal ratings were extracted from Table 2.4.1 - Augex model inputs - asset status - sub transmission lines' to calculate capacity added for each project. It should be noted that if the project was to comply with N-1 licence conditions, that the post rating equals the pre rating if the subtransmission line installed creates a parallel path with an existing subtransmission line. The rationale behind this capacity classification is that under N-1 conditions the network demand for the parallel subtransmission lines combined cannot be greater than the rating of the lowest rated subtransmission line; hence the second subtransmission line adds no capacity to the network segment.

2. The capacity factor for each project was calculated from the pre and post thermal line rating (Step 1), i.e.

   Capacity Factor (CF) = Post Rating (MVA)/Pre Rating (MVA)

   An average was taken of all project capacity factors to present on average, the capacity added to the network, as a ratio of the pre line thermal rating, through subtransmission line augmentation projects. As noted in step 1, N-1 projects add no capacity to the network resulting in a capacity factor of 1.

3. Both project costs (all costs excluding overheads) from Table 2.3.2 – 'Augex asset data - subtransmission lines' and capacity added to the network from each project (Step 1) was summed to calculate an average cost for adding network capacity ($/MVA) as follows:

   $/MVA = Sum of sample group project dollars/Sum of sample group capacity added (MVA)

4. Using the 2008/2009 Maximum demand (MVA) and line thermal rating recorded in Table 2.4.1 – 'Augex model inputs - asset status - sub transmission lines' the utilisation threshold for each project was calculated as follows:

   Utilisation Threshold (UT) = Maximum demand (MVA)/Line Thermal Rating (MVA)

5. It should be noted that for N-1 projects linked to an existing subtransmission line that the maximum demand of the line augmented was taken as the line rating if the maximum demand in the alternate parallel subtransmission line exceeds the rating of the subtransmission line being augmented. The rationale behind this utilisation threshold classification is linked to the operation of the network; with parallel subtransmission lines of substantially different ratings, the network is managed to avoid exceeding the capacity of the lowest rated paralleled subtransmission line. After applying the utilisation threshold classification, an average was taken of all project utilisation thresholds to present on average, the level of utilisation triggering subtransmission line augmentation projects.

Assumptions

In general, maximum demand data for subtransmission lines is not recorded for non N-1 projects. The demand threshold (used to calculate the utilisation threshold) was taken as the 2008/2009 maximum demand recorded in Table 2.4.1. It is assumed that the maximum line demand from 2008/09 will not vary considerably from the maximum demand causing the network constraint. For further details on maximum demand data refer to information provided with Table 2.4.1.

Issues

The cost of adding capacity ($/MVA) to a subtransmission line varies considerably due to the variance in work involved with each project. The main cost driver is the length of line (i.e. MVA/km) required to be augmented. This has not been taken into consideration in the AER's per unit cost calculation.

Due to a lack of available data, time and resource, Essential Energy was unable to supply peak demands under N-1 conditions for subtransmission feeders. This lack of data will cause inconsistencies in using the utilisation threshold against the utilisation apparent in table 2.4.1. However, even if Essential Energy was able to supply utilisations under N-1 conditions, the addition of N-1 requirements caused a number of subtransmission feeders to automatically be greatly over utilisation under N-1 conditions. Therefore the use of this data would also cause inconsistencies going forward.

Essential Energy has provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

Relationship to Planning Criteria

Subtransmission planning criteria considers the adequacy of the subtransmission network to not only meet the peak demand requirement following the forced outage of any single circuit line or substation element during peak periods, but also its capability to do so within component electrical and thermal ratings and voltage limits.

The optimal asset utilisation factor is 100%. It is not feasible to operate the entire network at this level due to the inability to cope with increased load levels or network emergencies. Based on the possible subtransmission line constraints:

- Exceeding equipment ratings
- Exceeding line thermal ratings
- Reduction in quality of supply (e.g. reduced voltage stability)
- Reduction in reliability and/or security of supply (due to aging equipment or increased failure rates)
- Inability to supply new or increased load

the utilisation threshold with reference to the thermal rating of the line will vary considerably. For example, a subtransmission line with a voltage constraint will require augmenting before reaching 100% utilisation. While projects initiated by rearranging zone substation load on the network to relieve lower system constraints (driven by a total lower cost than augmenting lower levels of the network), the utilisation threshold may be significantly less than the voltage constrained threshold. With reference to Table 2.4.5, the utilisation threshold calculated for subtransmission lines aligns with the mix of growth and N-1 projects completed within the period of interest.

The high capacity factor calculated aligns to planning criteria used within the business, generally when new investment is made there is excess capacity installed to what is required at the time. This caters for gradual load increases without the need for continual upgrading works, permitting long term lower capital spend and greatly decreases losses throughout the subtransmission line.

Relationship to Actual Historical Parameters at the time that Augmentations Occurred
Planning parameters calculated have been based on historic records for subtransmission lines requiring augmentation. The planning parameters are consistent with the best data Essential Energy has available.

Appropriate probability distribution to simulate the augmentation needs of network segment
Essential Energy has no reason to suspect anything other than a normal probability distribution with a firm bound at 100%.

Process applied to check unit costs, capacity factors and utilisation thresholds are a reasonable estimate for the network segment
Planning parameters calculated have been based on historic records for subtransmission lines requiring augmentation. The planning parameters are consistent with the best data Essential Energy has available.

Subtransmission Substations (BSPs), Subtransmission Switching Stations and Zone Substations

Definition of Network Segment
Within Essential Energy's network, zone substations are bounded by subtransmission lines and HV Feeders. Essential Energy owns and operates substations with secondary voltages at 22kV, 11kV, 6.6kV and in some instances 33kV. Zone substations have not been bundled with other network segments (i.e. subtransmission lines or HV feeders) due to its augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments.

Within Essential Energy's network, subtransmission substations are bounded by subtransmission lines and transmission lines. Essential Energy owns and operates subtransmission substations with primary voltages at 220kV, 132kV and 110kV. Subtransmission substations have not been bundled with other network segments (i.e. subtransmission lines or transmission lines) due to its augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments.

Calculation of Network Segment Parameters
Due to the limited number of subtransmission substation augmentation projects completed over the period of interest, subtransmission substation and zone substations have been bundled together, resulting in one set of planning parameters for both zone substations and subtransmission substations. Within the remainder of this section, zone substations and subtransmission substations will just be referred to as a substation. Details behind the calculation of substation segment parameters are presented and discussed below.

Data sources

To develop substation planning parameters, Essential Energy first sourced data directly from other tables submitted within the Reset RIN, which includes:

- Per unit rate for substations - total expenditure linked to completed projects was sourced directly from Table 2.3.1 - Augex asset data - Subtransmission substations, switching stations and zone substations
    - Total Direct
    - Major contracts - non related party
    - Land

- Table 5.4.1 Non-Coincident & Coincident Maximum Demand
    - Maximum demand (MVA)

Additional data was sourced directly from the following Essential Energy systems:

- ProjectWise (Archived Drawings and Project Reports)
  - Existing Network Configuration
  - Present Network Configuration

- ENMAC
  - Present Network Configuration

Methodology

Essential Energy has used the following methodologies and assumptions in determining the network parameters for substations:

1. Based on completed substation augmentation projects, pre and post normal cyclic ratings were extracted from Table 2.3.1 – 'Augex asset data - Subtransmission substations, switching stations and zone substations'

2. Based on the pre and post transformer capacity installed and each transformer capacity installed (for multiple transformer sites). The pre and post rating was calculated as follows:

   a. For single transformer substations the zone substation rating (pre and post) was capped at a maximum of 15MVA regardless of the size of the transformer.
   b. For sites with multiple transformers, the largest parallel transformer was excluded from the rating (pre or post).

3. The capacity factor for each project was calculated from the pre and post rating calculated in step 2, i.e.

   Capacity Factor (CF) = Post Rating (MVA)/Pre Rating (MVA)

   An average was taken of all project capacity factors to present on average, the capacity added to the network, as a ratio of the pre rating, through substation augmentation projects.

4. Both project costs (all costs excluding overheads) from Table 2.3.1 – 'Augex asset data - Subtransmission substations, switching stations and zone substations' and capacity added to the network from each project (Step 2) was summed to calculate an average cost for adding network capacity ($/MVA) as follows:

   $/MVA = Sum of sample group project dollars/Sum of sample group capacity added (MVA)

5. Using the last maximum demand (MVA) recorded before project completion and rating calculated in step 2, the utilisation threshold for each project was calculated as follows:

   Utilisation Threshold (UT) = Maximum Demand (MVA)/Substation Rating (MVA)

   An average was taken of all project utilisation thresholds to present on average, the level of utilisation triggering substation augmentation projects.

Assumptions

It is assumed that the demand extracted in step 5 is to be the threshold demand. It should be noted that under this assumption, utilisation thresholds for some projects may appear low due to the plan after augmentation to transfer load from nearby substations to relieve other network constraints. Essential Energy believes this to be a reasonable estimate.

Issues

- Lack of previous subtransmission substation augmentation projects over the period of interest to generate separate subtransmission substation planning parameters.
- Many substation augmentation projects over the period of interest are in relation to N-1 projects or to relieve constraints on adjacent zone substations. These types of projects result in little capacity added to the network segment due to N-1 supply requirements and result in lower utilisation thresholds due to load transfers after the substation was augmented.
- Due to a lack of time and resource, Essential Energy was unable to supply substation ratings using the methodology outlined above regarding the capping of substation output to 15MVA for non N-1 substations. This lack of data will cause some inconsistencies in using the utilisation threshold against the utilisation apparent in table 2.4.3. However, the number of zone substations this applies to will be relatively small.

Due to poor records and a lack of time and resource, a multitude of errors are expected in the input data for this table. These errors will multiply throughout the various calculations performed. Essential Energy has provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

Relationship to Planning Criteria

Subtransmission planning criteria considers the adequacy of the subtransmission network to not only meet the peak demand requirement following the forced outage of any single circuit line or substation element during peak periods, but also its capability to do so within component electrical and thermal ratings and voltage limits.

The optimal asset utilisation factor is 100%. Clearly, it is not feasible to operate the entire network at this level due to the inability to cope with increased load levels or network emergencies. Based on the possible substation constraints:

- Exceeding equipment ratings
- Exceeding cable/conductor thermal ratings
- Reduction in quality of supply (e.g. reduced voltage stability)
- Reduction in reliability and/or security of supply (due to aging equipment or increased failure rates)
- Inability to supply new or increased load

the utilisation threshold with reference to the name plate rating of the substation N-1 transformer capacity will vary considerably. For example, a circuit breaker may require augmenting before the substation could reach 100% utilisation. While projects initiated by rearranging HV feeder load on the network to relieve lower system constraints (driven by a total lower cost than augmenting lower levels of the network), the utilisation threshold may be significantly less. With reference to Table 2.4.5, the utilisation threshold calculated for zone substations aligns with the mix of growth and N-1 projects completed within the period of interest.

The capacity factor calculated aligns to planning criteria used within the business. Generally when a new investment is made there is excess capacity installed to what is required at the time. This caters for gradual load increases without the need for continual upgrading works, permitting long term lower capital spend and greatly decreases losses.

Relationship to Actual Historical Parameters at the time that Augmentations Occurred
Planning parameters calculated have been based on historic records for substations requiring augmenting. The planning parameters are consistent with the best data Essential Energy has available.

Appropriate probability distribution to simulate the augmentation needs of network segment

Essential Energy believes that a biomodal distribution would be the most appropriate distribution to simulate augmentation needs of substations, with the first peak representing substations below 15MVA maximum demand and second peak representing N-1 (maximum demand over 15MVA) substations.

Process applied to check unit costs, capacity factors and utilisation thresholds are a reasonable estimate for the network segment

Planning parameters calculated have been based on historic records for substations requiring augmenting. The planning parameters are consistent with the best data Essential Energy has available.

High Voltage feeders
Definition of Network Segment
Within Essential Energy's network, HV feeders are bounded by zone substations and distribution substations, i.e. HV feeders originate from zone substations distributing electricity to distribution substations. Essential Energy owns and operates HV Feeders at 22kV, 11kV, 6.6kV, SWER (19.1kV and 12.7kV), and in some instances 33kV. Essential Energy owns and operates both subtransmission and distribution lines at 33kV. HV Feeders have not been bundled with other network segments (i.e. Distribution substations and/or zone substations) due to its augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments. The HV Feeder asset class can be further broken down into underground and overhead asset types.

Calculation of Network Segment Parameters

Due to the lack of available data and level of time and resources that would be required to extract parameter input calculation data for each HV Feeder project, there were not enough sample group projects linked to each underground and overhead or Urban, Rural (Short/Long) feeders, hence one set of planning parameters have been calculated to represent all HV feeders types.

Data sources

To develop HV Feeder planning parameters, Essential Energy first sourced data directly from other tables submitted within the Reset RIN, which includes:

- 2.3.3.2 Augex data - HV feeders Expenditure:
  - Total Expenditure (Excluding Overheads)

- Use Table 2.4.2 - Augex model inputs - asset status - high voltage feeders:
  - Thermal Rating 2012/2013
  - Demand Recorded 2008/09

Additional data was sourced directly from the following Essential Energy systems:

- Planners Database, with analysis requiring the use of the following fields:
    - Project ID
    - WASP Job Number
    - Planning Region
    - IO Region
    - Works Area
    - Depot
    - Shire
    - Project Name
    - Project Description
    - Financial Year
    - Milestone Status
    - Zone Substation
    - BSP
    - Feeder Code
    - Feeder
    - Work Type
    - WASP Program
    - AER Primary Category
    - SAMP Primary Code
    - SAMP Primary Category
    - Asset Type
    - Construction Completed
    - Urban Rural
    - SCOPED_BY

- WASP (Project Drawings and Reports)
    - Pre HV Feeder Thermal Ratings

Methodology

Essential Energy has used the following methodologies and assumptions in determining the network parameters for HV Feeders:

1. Manually extract first trunk (Exiting from the Zone Substation) and non-first trunk segment augmentation projects from the Planners Database based on reading the ‘Project Name’ and ‘Project Description’ for all projects that satisfy the following criteria:

    - Construction Completed
        - 2010
        - 2011
        - 2012
    - Financial Years:
        - 2008/09
        - 2009/10
        - 2010/11
        - 2011/12
        - 2012/13
    - Milestone Status:
        - Complete
    - AER Primary Category:
        - Reliability (REL)
        - Growth (GRI)

2. Assign project expenditure (excluding overheads) to each HV Feeder project identified in step 1 based on the Project ID and using individual project data from table 2.3.3.2 ‘Augex data - HV feeders Expenditure’.

3. Extract both the 2012/2013 Thermal Rating and 2008/09 Demand recorded from Table 2.4.2 – ‘Augex model inputs - asset status - high voltage feeders’ and link to the appropriate HV Feeder projects.

4. For a subset of first trunk segment augmentation projects extracted in step 1, analyse project drawings and reports to extract pre HV Feeder cable/conductor type.

5. Based on the cable/conductor type extracted in step 4, calculate the pre thermal rating as per the procedure applied in Table 2.4.2 – ‘Augex model inputs - asset status - high voltage feeders’.

6. Based on the pre rating calculated in step 5 and 2012/2013 thermal line rating (post rating) extracted in step 3, calculate the capacity added per first trunk segment sample group project.

7. Based on total first trunk segment augmentation project expenditure and total sample group first trunk segment augmentation project expenditure, scale the sample group calculated capacity added (MVA) to estimate the total capacity added by first trunk segment augmentation projects over the period of interest.

8. Based on the first trunk segment and non-first trunk segment augmentation project expenditure assigned in step 2 and estimated total thermal capacity added through first trunk segment augmentation projects in step 7 over the period of interest specified in step 1. An average cost for adding network capacity ($/MVA) was calculated as follows:

   $/MVA = Total HV Feeder Project Expenditure/First Trunk Segment Capacity Added (MVA)

9. Based on the pre rating for each sample group project calculated in step 5 and 2012/2013 (post) thermal rating extracted in step 3, calculate the capacity factor for each sample group project as follows:

   Capacity Factor (CF) = Post Rating (MVA)/Pre Rating (MVA)

   An average was taken of all sample group project capacity factors to present on average the capacity added to the network, as a ratio of the pre thermal rating, through HV Feeder augmentation projects.

10. Using the 2008/2009 Maximum Demand (MVA) linked to each project in step 3 and the HV Feeder pre thermal rating calculated in step 5, the utilisation threshold for each sample group project was calculated as follows:

    Utilisation Threshold (UT) = 2008/09 Maximum Demand (MVA)/Pre Line Thermal Rating (MVA)

    An average was taken of all sample group project utilisation thresholds to present on average the level of utilisation triggering HV Feeder augmentation projects.

11. Based on the 2012/2013 Thermal Rating and 2008/09 Maximum Demand linked to each project in step 3 calculate the utilisation threshold for each non-first trunk segment augmentation project as per step 10. Take an average of the utilisation thresholds to calculate the average utilisation threshold for non-first trunk segment augmentation projects.

12. Pre and Post rating of non-first trunk segment augmentation projects are the same, thus a capacity factor of 1 is used to maintain consistency with HV feeder capacities specified as per request by the AER with Table 2.4.2 - Augex model inputs - asset status - high voltage feeders, i.e. HV feeder capacity is based on the first trunk segment only, thus augmentation along the feeder adds zero capacity to the HV feeder.

13. Calculate a weighted average capacity factor and utilisation threshold based on the number of:
    a. First trunk and non-first trunk segment augmentation projects and
    b. Capacity factors and utilisation thresholds calculated in steps 9 to 12.

Assumptions

The demand threshold (used to calculate the utilisation threshold) was taken as the 2008/2009 maximum demand recorded in Table 2.4.2. It is assumed that the maximum line demand from 2008/09 will not vary considerably from the maximum demand causing the network constraint. For further details on maximum demand data refer to basis of preparation for Table 2.4.2.

It is assumed that all HV feeders (pre and post for augmentation projects) have a 50 degree Celsius rating, as per the information provided with Table 2.4.2. Whilst this is most likely not the case, Essential Energy believes it to be a reasonable assumption based on the limited data available.

Issues

Based on the AER rating definition for HV feeders, discussed in Table 2.4.2, there are many augmentation projects that theoretically result in zero capacity added to the network. This generates a high per unit cost, low capacity factor and utilisation threshold. Generally, for HV feeders (and lower levels of the network) practical ratings are based on the lesser of:

- **Thermal Rating**: determined by the environment and the manufacturer’s specifications.
- **Voltage Rating linked to license conditions:** is dependent on many characteristics of the feeder of interest, such as:
    - The unique load distribution along the feeder
    - Length of feeder (backbone and spurs)
    - Conductor type and condition along the feeder
    - Use of voltage regulators along the feeder
    - Distribution transformer Taps

Non-first trunk segment HV Feeder augmentation projects address voltage constraints along the feeder, increasing the voltage rating (hence total capacity) of the Feeder. For such projects, the relationship between capacity added and associated cost is ignored due to the required AER HV feeder rating definition.

Due to poor records and a lack of time and resource, a multitude of errors are expected in the input data for this table. These errors will multiply throughout the various calculations performed, exacerbating any possible errors. Essential Energy has provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

Relationship to planning criteria

Distribution planning criteria considers the adequacy of the distribution network to not only meet the peak demand requirement, but also its capability to do so within component electrical and thermal ratings and voltage limits.

The optimal asset utilisation factor is 100%. Clearly, it is not feasible to operate the entire network at this level due to the inability to cope with increased load levels or network emergencies. Based on the possible HV feeder constraints:

- Exceeding equipment ratings
- Exceeding line thermal ratings
- Reduction in quality of supply (e.g. reduced voltage stability)
- Reduction in reliability and/or security of supply (due to aging equipment or increased failure rates)
- Inability to supply new or increased load

the utilisation threshold with reference to the first trunk segment thermal rating will vary considerably. For example, a voltage constrained (very common for HV Feeders) HV feeder will require augmenting before reaching 100% utilisation. With reference to Table 2.4.5, the utilisation threshold calculated for HV feeders aligns, as per the required AER rating definitions, to projects completed within the period of interest. However, it should be noted that the utilisation threshold calculated, as per the AER's definitions, is not practical for use to simulate the augmentation needs of the network.

The very low capacity factor does not align to planning criteria used within the business. The capacity factor calculated, as per the definitions, is not practical for use to simulate capacity added to the network through augmentation projects. Generally, when new investment is made there is excess capacity installed to what is required at the time. This caters for gradual load increases without the need for continual upgrading works, permitting long term lower capital spend and greatly decreases losses throughout the HV feeder. As per the required definitions for calculating the parameter, the capacity added to the network from non-first trunk augmentation projects is not captured.

Relationship to Actual Historical Parameters at the time that Augmentations Occurred

The data used in the calculations is within the period of interest. Essential Energy believes the parameters calculated (as per the definitions provided) align approximately to parameters at the time augmentation occurred. However, it should be noted that by using the AER's planning parameter calculation definitions, the parameters calculated provide an insignificant correlation to the augmentation characteristics and needs of HV feeders.

Appropriate probability distribution to simulate the augmentation needs of network segment

Essential Energy has no reason to suspect anything other than a normal probability distribution with a firm bound at 100%.

Process applied to check unit costs, capacity factors and utilisation thresholds are a reasonable estimate for the network segment

The definitions of parameter calculations result in an insignificant correlation to actual augmentation characteristics of the network segment. To provide a reasonable estimate, the parameters must be linked to the true ratings of the network segment in question.

Distribution substations

Definition of Network Segment

Within Essential Energy's network, distribution substations are bounded by HV feeders and LV feeders, i.e. distribution substations connect feeders of different voltages. Distribution substations operate at 22kV, 11kV, 6.6kV, SWER (19.1kV and 12.7kV), and in some instances 33kV and variations of single phase and three phase at those voltages. Distribution substations have not been bundled with other network segments (i.e. HV Feeders and/or LV Feeders) due to its augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments. The distribution substation asset class can be further broken down into the following asset types:

- Pole Mounted:
  - Pole Substation
  - Supported Platform Substation
  - 2 Pole Platform Substation

- Ground Mounted:
  - Pad/Kiosk Substation
  - Ground Substation

- Indoor:
  - Chamber Substation

Note that the Distribution Substations excludes SWER isolators, as per RIN adjustments.

Calculation of Network Segment Parameters

It should be noted that the cost variance between augmenting overhead and underground distribution substations varies considerably, but due to limited data records and the level of resources required to extract parameter input data over the 2008/09 – 2013/14 period, single distribution substation planning parameters have been calculated to represent both underground an overhead distribution substations for the periods of interest.

Data sources

To develop distribution substation planning parameters data was sourced directly from the following Essential Energy systems:

- WASP (Asset Data and Maximum Demand Recordings (MDI))
  - Region
  - Area Coordinator
  - Depot
  - Feeder Area
  - Maintenance Area
  - Asset ID
  - Asset Label
  - Status
  - Critical Equipment
  - Type
  - Current Total kVA
  - Current Tap Position
  - Current Read Date
  - KVA at Current Read Date
  - Load A Phase (amps)
  - Load B Phase (amps)
  - Load C Phase (amps)
  - kVA
  - 1st Prev. Read Date
  - KVA at 1st Prev. Read Date
  - Load A Phase (amps) 1

- Load B Phase (amps) 1
- Load C Phase (amps) 1
- kVA
- 2nd Prev. Read Date
- KVA at 2nd Pre. Read Date
- Load A Phase (amps) 2
- Load B Phase (amps) 2
- Load C Phase (amps) 2
- kVA
- 3rd Prev. Read Date
- KVA at 3rd Prev. Read Date
- Load A Phase (amps) 3
- Load B Phase (amps) 3
- Load C Phase (amps) 3
- kVA

- PeopleSoft (Financial Data)
  - Fiscal Year
  - Accounting Date
  - Transaction Date
  - Account Number
  - Account Description
  - Currency Code
  - Total Resource Amount
  - Journal Line Description
  - Journal Header Description
  - Project ID
  - Project Description
  - Proj Resource Type
  - Proj Resource Category
  - Proj Analysis Type
  - Resource Quantity
  - Project Type Descr
  - Item Description
  - Descr

Methodology

Essential Energy has used the following methodologies and assumptions in determining the network parameters for distribution substations:

1. All distribution substations that have maximum demand indicator records before the substation was augmented were extracted from WASP.

2. From step 1 data set, the corresponding distribution transformer rating was extracted at the time the maximum demand was recorded.

3. The capacity factor for each distribution substation augmented was calculated from the rating extracted in step 2 (pre) and current rating from data extracted in step 1 (post) as follows:

   Capacity Factor (CF) = (1.5 x Post Rating (kVA))/ (1.5 x Pre Rating (kVA))

   The rating was taken as 1.5 x the name plate of the distribution transformer as per planning criteria. An average was taken of all distribution substation capacity factors to present on average, the capacity added to the network, as a ratio of the pre distribution transformer rating, through distribution substation augmentation projects.

4. Based on distribution substation sites extracted in step 1, all projects linked to each site were extracted. Augmentation projects were manually extracted from all projects linked to the substation sites.

5. From the projects extracted in step 4, corresponding expenditure was extracted (excluding overheads) from PeopleSoft.

6. Both project costs (step 5) and capacity added to the network from each project (Step 3) was summed to calculate an average cost for adding network capacity ($/MVA) as follows:

   $/MVA = Sum of sample group project dollars ($)/Sum of sample group capacity added (MVA)

7. Using the maximum demand indicator recording at each site extracted in step 1 and pre transformer rating extracted in step 2, the utilisation threshold for each project was calculated as follows:

   Utilisation Threshold (UT) = Maximum demand (kVA)/Transformer Rating (kVA) x 1.5)

   The rating was taken as 1.5 x the name plate of the distribution transformer as per planning criteria. An average was taken of all project utilisation thresholds to present on average, the level of utilisation triggering distribution substation augmentation projects.

Assumptions

The demand threshold (used to calculate the utilisation threshold) was taken as the last Maximum Demand Indicator (MDI) reading, which may be many years before the distribution substation was augmented. Unfortunately, this is the only demand data that is available. As a result, this is the best estimate for the utilisation threshold Essential Energy can produce.

Issues

- Regarding distribution substation augmentation projects, few are actually linked to the site (WASP data). This has resulted in a reduced sample size for the per unit parameter ($/MVA) calculation.
- Sample data may be skewed towards larger distribution substations. This is due to the limitations on sourcing input planning parameter data; hence planning parameters may not represent the majority of Essential Energy's distribution substation augmentation projects. Demand data (MDI) is mainly from larger distribution transformers (above 200kVA).
- Smaller (mostly overhead distribution substations) are likely to have a higher utilisation threshold before augmenting, this is not captured due to the limited sample group available (i.e. sites linked to MDIs).

Due to poor records and a lack of time and resource, a multitude of errors are expected in the input data for this table. These errors will multiply throughout the various calculations performed. Essential Energy has provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

Relationship to planning criteria

Distribution planning criteria, considers the adequacy of distribution substations to not only meet the peak demand requirement, but also its capability to do so within component electrical and thermal ratings and voltage limits.

As per distribution planning criteria, the optimal asset utilisation factor is 150%. Clearly, it is not feasible to operate the entire distribution substation asset base at this level due to the inability to cope with increased load levels or network emergencies. Based on the possible distribution substation constraints:

- Exceeding equipment ratings
- Exceeding cable/conductor thermal ratings
- Reduction in quality of supply (e.g. reduced voltage stability)
- Reduction in reliability and/or security of supply (due to aging equipment or increased failure rates)
- Inability to supply new or increased load

the utilisation threshold with reference to the thermal rating will vary considerably. With reference to Table 2.4.5, the utilisation threshold calculated for distribution substations aligns with the projects completed within the period of interest.

The capacity factor calculated aligns to planning criteria used within the business. Generally, when new investment is made there is excess capacity installed to what is required at the time. This caters for gradual load increases without the need for continual upgrading works, permitting long term lower capital spend and greatly decreases losses.

Relationship to Actual Historical Parameters at the time that Augmentations Occurred
The data used in the calculations is within the period of interest. Essential Energy believes the parameter calculated aligns approximately to parameters at the time augmentation occurred.

Appropriate probability distribution to simulate the augmentation needs
As distribution substations are a high volume asset, with no substantial recent change in planning criteria Essential Energy has no reason to suspect anything other than a normal probability distribution with a firm bound at 100%.

Process applied to check unit costs, capacity factors and utilisation thresholds are a reasonable estimate for the network segment
Planning parameters calculated have been based on historic records for distribution substations requiring augmenting. The planning parameters are consistent with the best data Essential Energy has available.

LV Network

Definition of Network Segment

Within Essential Energy's network, low voltage feeders are installed in both three phase and single phase configurations and are bounded by distribution substations and customer services. Essential Energy owns and operates low voltage feeders at 415V three phase, or 240V single phase. Low voltage feeders have not been bundled with other network segments (i.e. distribution substations) due to its augmentation needs being an independent function of surrounding network segments, therefore requiring augmentation at different points in time with respect to other network segments.

Calculation of Network Segment Parameters

The cost variance between augmenting overhead and underground low voltage feeders varies considerably, but due to a few underground low voltage augmentation projects over the 2008/09 – 2013/14 period, single low voltage feeder parameters have been calculated to represent both underground and overhead for the periods of interest.

Data sources

To develop low voltage feeder planning parameters, Essential Energy sourced data from the network planning database specifically for reconductoring jobs. This data includes the following:

PLANNING_REGION_DESC
PROJECT_ID
PROJECT_NAME
FINANCIAL_YEAR
CONST_COMPLETE_DATE
MILESTONE
LOCKED
ACTUAL_DOLLARS
ACTUAL_HOURS
NEW_CONDUCTOR_TYPE
OLD_CONDUCTOR_TYPE
HV_METRES_RECONDUCTOR
LV_METRES_RECONDUCTOR
CU_REPLACEMENT_METRES
STEEL_REPLACEMENT_METRES
PEAK_LOAD (KVA)
LOAD_LOSS_FACTOR
PHASES
VOLTAGE_DESC
Project Type1

Methodology

Essential Energy has used the following methodologies and assumptions in determining the network parameters for low voltage feeders:

1. Completed low voltage feeder projects were screened to ensure the input data was reasonable.

2. Based on completed low voltage feeder augmentation projects, pre and post conductor types ratings where extracted from the source data, and used to calculate MVA capacity using a 50 degrees Celsius installed temperature.

3. Capacity added was calculated using pre and post thermal line rating for each project.

4. The capacity factor for each project was calculated from the pre and post thermal line rating (Step 1), i.e.

   Capacity Factor (CF) = Post Rating (MVA)/Pre Rating (MVA)

An average was taken of all project capacity factors to present on average, the capacity added to the network, as a ratio of the pre line thermal rating, through low voltage feeder augmentation projects.

5. Some projects will include a number of upgrades to spans with different conductors. For the purpose of the augex model, Essential Energy have used total project cost/max capacity increase for each project to define the $/MVA on each project.

6. An average $/MVA across all projects was calculated.

7. Using the maximum demand (MVA) and line thermal rating recorded in the source data, the utilisation threshold for each project was calculated as follows:

   Utilisation Threshold (UT) = Maximum demand (MVA)/Line Thermal Rating (MVA)

Assumptions

- In general, maximum demand data for low voltage feeders is not recorded, therefore the demand data in the source file is estimated data based on local knowledge at the time of project initiation.
- Exact conductor types for low voltage feeders is not well recorded, therefore the conductor data in the source file is estimated data based on local knowledge at the time of project initiation.
- Low voltage feeder design temperature is not well recorded, therefore Essential Energy has used a consistent 50 degree Celsius installed temperature for the calculation of LV feeder rating.
- The derived utilisation levels are unlikely to be as calculated (a utilisation level above 1 shows this), however they are derived using the best data and assumptions available to Essential Energy and provide a consistent basis to work from.

Issues

Generally, LV feeders practical ratings are based on the lesser of:

- **Thermal Rating:** determined by the environment and the manufacturers specifications.
- **Voltage Rating linked to license conditions:** is dependent on many characteristics of the feeder of interest, such as:
  - The unique load distribution along the feeder
  - Length of feeder
  - Conductor type and condition along the feeder

Voltage based ratings have not been considered in these calculations.

The cost of adding capacity ($/MVA) to a low voltage feeder varies considerably due to the variance in work involved with each project. Outside of whether the low voltage feeder is overhead or underground, the main cost driver is the length of line (MVA/km) required to be upgraded. This has not been taken into consideration with the per unit cost calculation.

Due to poor records and a lack of time and resource, a multitude of errors are expected in the input data for this table. These errors will multiply throughout the various calculations performed. Essential Energy has provided their best estimate of the data. This information should be used with caution for benchmarking or decision making purposes.

Relationship to Planning Criteria

The planning criteria, considers the adequacy of the low voltage network to meet the peak demand requirement within component electrical and thermal ratings and voltage limits.

The optimal asset utilisation factor is 100%. Clearly, it is not feasible to operate the entire network at this level due to the inability to cope with increased load levels or network emergencies. Based on the possible low voltage feeder constraints:

- Exceeding equipment ratings
- Exceeding line thermal ratings
- Reduction in quality of supply (e.g. reduced voltage stability)
- Reduction in reliability and/or security of supply (due to aging equipment or increased failure rates)
- Inability to supply new or increased load

the utilisation threshold with reference to the thermal rating of the line will vary considerably. For example, a voltage constrained low voltage feeder will require augmenting before reaching 100% utilisation.

The high capacity factor calculated aligns to planning criteria used within the business. Generally, when new investment is made there is excess capacity installed to what is required at the time. This caters for growth in network demands, without the need for continual upgrading works, permitting long term lower capital spend and greatly decreases losses throughout the low voltage feeder.

Relationship to Actual Historical Parameters at the time that Augmentations Occurred

The data used in the calculations is within the period of interest. Essential Energy believes the parameter calculated aligns approximately to parameters at the time augmentation occurred.

Appropriate probability distribution to simulate the augmentation needs

As low voltage feeders are a high volume asset, with no substantial recent change in planning criteria (disregarding any change to standard conductor types), Essential Energy has no reason to suspect anything other than a normal probability distribution with a firm bound at 100%.

Process applied to check unit costs, capacity factors and utilisation thresholds are a reasonable estimate for the network segment

Utilisation thresholds have been based on historic utilisation records for low voltage feeders requiring reconductoring. Whilst the utilisation limit outcome is much higher than expected, it is consistent with the best data Essential Energy has available.

2.4.6 Capex and net capacity added by segment group

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

High level summary

Methodology and Assumptions

- Total augex less what was customer initiated & capacity related augmentation equals network service provider (NSP) initiated & capacity related augmentation.
- Totals are generated from table 2.3.4 of the Reset RIN template.
- Where there is no split required, for example zone substations, totals are from table 2.3.4 less totals from table 2.5 Connections in the Reset RIN template (customer initiated) which equals NSP initiated augmentation.

- Where there is a split required, for example high voltage feeders, totals are sourced from tables 2.3.4 and 2.5 of the Reset RIN template to calculate the NSP initiated augmentation and then split based on percentages (for customer initiated and NSP initiated augmentation) provided by subject matter experts. The split for the total augex RIN mapping is then determined by the addition of NSP initiated and customer initiated augmentation.
- Unmodelled augmentation relates to customer metering and load control, SCADA, unknown and other salaries and wages adjustments in accruals. SCADA and Customer metering and load control has been included as it is not considered to be primarily related to peak demand and capacity needs.

Reliability of information

The data provided is considered to be unreliable, hence caution should be taken when using for benchmarking or decision making purposes.

Detailed Summary

Source of information

Expenditure Sources:

- Table 2.5.1 Descriptor Metrics (Customer Initiated CAPEX: HV Feeders, Distribution Substations & LV):
  - Distribution Substation Installed (Total Spend $000's)
  - Augmentation HV (Total Spend $000's)
  - Augmentation LV (Total Spend $000's)

- The general finance Basis of Preparation (BoP) in section 1.8 details data sources used to populate Network Service Provider (NSP) Initiated CAPEX for:
  - Subtransmission substations & Subtransmission switching stations
  - Subtransmission lines
  - Zone substations

- Planners Database (used to calculate percentage split into Urban, Short Rural and Long Rural categories for HV Feeders and Distribution Substations):
    - Feeder Code
    - AER_CAT_FILTER1_ID_DESCRIPTION
    - AER_CAT_FILTER2_ID_DESCRIPTION
    - ACTUAL_DOLLARS
    - HV Feeder classifications provided by Essential Energy's Reliability Team.

Capacity Sources:

- Table 2.5.1 Descriptor Metrics (Customer Initiated Distribution Substation Capacity Added):
  - Residential (MVA added)
  - Commercial/Industrial (MVA added)
  - Subdivision (MVA added)
  - Embedded Generation (MVA added)

- Table 2.4.5:
  - Average unit cost of augmentation for the network segment for the current regulatory control period.

- Table 2.4.3:
  - 2012-13 & 2008-09:
    - Tx name plate total (in service)
    - Tx normal cyclic total
    - N-1 emergency

- Table 2.3.1:
  - Total direct expenditure
  - Major contracts - non related party
  - Land purchase

Methodology and Assumptions

Customer Initiated & Capacity - Related Augmentation Expenditure

Based on customer initiated project expenditure and feeder type classification linked to each project, a percentage breakdown was developed to split the total asset class augmentation expenditure into the requested segment groups (urban, short rural and long rural). The following project types from the planner's database were linked back to the asset class with urban, short rural and long rural classifications:

- HV Feeders:
  - Lines and Cables – OH
  - Lines and Cables – UG
- Distribution Transformers & LV:
  - Transformers/Substations
  - LV
- Not Used:
  - Other
  - Switchgear

Customer Initiated & Capacity - Related Augmentation Capacity Added

HV Feeders

Capacity added to the network from customer initiated HV Feeder augmentation projects was calculated by using per unit costs ($/MVA) from table 2.4.5 and expenditure over the periods of interest from table 2.4.6.

Explained in the Basis of Preparation (BoP) provided with table 2.4.5, as per AER definitions for calculating the planning parameters, it is important to note that capacity added to the network from non-first trunk HV feeder augmentation projects is not captured. This results in the calculated planning parameters having a weak correlation (if any at all) to the expenditure, resultant capacity added and also the augmentation characteristics and needs of HV feeders.

Please refer to the BoP provided with table 2.4.5 that explains planning parameter calculations and respective parameter confidence in detail. Both the accuracy of parameters used and expenditure breakdown reflects the calculated capacity added confidence.

Distribution Substations & LV

Capacity added to the network from customer initiated distribution transformer augmentation projects was calculated from table 2.5.1 'Descriptor Metrics' by summing the capacity added from each connection subcategory below:

- Residential

- Commercial/Industrial
- Subdivision
- Embedded Generation

and using the financial percentage breakdown calculated in the previous section to distribute the total capacity added across each requested segment group (urban, short rural and long rural).

Capacity added to the network from customer initiated LV augmentation projects was calculated by using per unit costs ($/MVA) from table 2.4.5 and expenditure over the periods of interest from table 2.4.6. Using the financial percentage breakdown, total capacity added to the LV network was distributed across each requested segment group (urban, short rural and long rural).

Please refer to the Basis of Preparation (BoP) provided with table 2.4.5 that explains planning parameter calculations and respective parameter confidence in detail. Both the accuracy of parameters used and expenditure breakdown reflects the calculated capacity added confidence.

NSP-Initiated & Capacity-Related Augmentation Expenditure
Subtransmission lines, subtransmission, zone substations and subtransmission switching stations
Network Service Provider (NSP) augmentation expenditure was sourced as per the general finance BoP in section 1.8.

HV Feeders, Distribution Substations & LV
NSP augmentation expenditure was sourced as per the general finance BoP in section 1.8.

Based on NSP project expenditure and feeder type classification linked to each project a percentage breakdown was developed to split the total asset class augmentation expenditure into the requested segment groups (urban, short rural and long rural). The following project types from the planner's database were linked back to the asset class with urban, short rural and long rural classifications:

- HV Feeders:
    - Lines and Cables – OH
    - Lines and Cables – UG
- Distribution Transformers & LV:
    - Transformers/Substations
    - LV
- Not Used:
    - Other
    - Switchgear

NSP-Initiated & Capacity-Related Augmentation Capacity Added

Subtransmission lines

Capacity added to the network from NSP initiated subtransmission line augmentation projects was calculated by using per unit costs ($/MVA) from table 2.4.5 and expenditure over the periods of interest from table 2.4.6. The capacity types are defined below:

- Type 1: In Service Rating
- Type 2: N-1 Emergency Rating

Please refer to the BoP provided with table 2.4.5 that explains planning parameter calculations and respective parameter confidence in detail. Both the accuracy of parameters used and expenditure breakdown reflects the calculated capacity added confidence.

Subtransmission, zone substations and subtransmission switching stations

Capacity added to the network from NSP initiated subtransmission, zone substations and subtransmission switching stations augmentation projects was calculated by developing per unit rates ($/MVA) for each of the capacity types below:

- Type 1: Name Plate (In Service) Rating
- Type 2: Transformer Normal Cyclic Rating
- Type 3: N-1 Emergency Rating

and expenditure over the periods of interest from table 2.4.6.

The per unit rates for each capacity type were calculated using total dollars over 2008/09-2012/13 from Table 2.3.1 - Augex asset data - Subtransmission substations, switching stations and zone substations and total capacity (for each type) change over the same period from Table 2.4.3.

HV Feeders

Capacity added to the network from NSP initiated HV feeder augmentation projects was calculated by using per unit costs ($/MVA) from table 2.4.5 and expenditure over the periods of interest from table 2.4.6.

Explained in the BoP provided with table 2.4.5, as per AER definitions for calculating the planning parameters, it is important to note that capacity added to the network from non-first trunk HV feeder augmentation projects is not captured. This results in the calculated planning parameters providing very little correlation (if any at all) to the expenditure and resultant capacity added and also the augmentation characteristics and needs of HV feeders.

Please refer to the BoP provided with table 2.4.5 that explains planning parameter calculations and respective parameter confidence in detail. Both the accuracy of parameters used and expenditure breakdown reflects the calculated capacity added confidence.

Distribution Substations & LV

Capacity added to the network from NSP initiated distribution substations & LV augmentation projects was calculated by using per unit costs ($/MVA) from table 2.4.5 and expenditure over the periods of interest from table 2.4.6. Capacity added was calculated separately for distribution substations and LV projects.

Please refer to the BoP provided with table 2.4.5 that explains planning parameter calculations and respective parameter confidence in detail. Both the accuracy of parameters used and expenditure breakdown reflects the calculated capacity added confidence.

Use of estimated information

All capacity added data in table 2.4.6 can be considered as estimates based on engineering data and a variety of assumptions.

Reliability of information

The data provided is considered to be unreliable and is based on Essential Energy’s best estimates, therefore caution should be used taken when using it for decision making or benchmarking purposes.

Worksheet 2.5 – Connections

2.5.1 – Descriptor metrics

Underground Overhead – 08/09 to 12/13 for Residential/Commercial and Subdivision Connections

Compliance with requirements of the notice

The Notice requires the number of new Underground and Overhead connections for Rural, Commercial/Industrial and Subdivision premises for each financial year from 08/09 to 12/13. The information has been determined using Energy extracts as at the end of each financial year and categorising all new premises added to Energy within the period.

Source of information

Energy/Peace

- Premises with a current customer that are within the Essential Energy network. Data extracted as at the end of each financial year within the reporting period. This excludes Residential/Commercial flag which wasn't available in historical data.
- Premise with Residential/Commercial flag at time of report preparation.

Smallworld

- Premises with Underground/Overhead flag.

WASP

- Substations with Underground/Overhead flag.

NIEIR Report

- Report previously submitted for Customer growth figures.

Methodology and Assumptions

The figures previously provided for the NIEIR report were used to determine the total new connections for both residential and commercial customers.

A ratio of underground to overhead connections was derived from Smallworld for residential and commercial premises for each reporting year. This ratio was applied to the NIEIR figures.

Assumptions

- Essential Energy has no Subdivision assets based on the definition "is intended to capture expenditure in connecting un-reticulated lots or areas."

Use of estimated information

Essential Energy has used estimated information for premises where Residential/Commercial or Overhead/Underground could not be determined.

An estimate was required in the following cases:

- Premise data is historical where status data is current. Premises may have become extinct but exist historically therefore no Residential/Commercial value can be determined.
- Premises have no network connect therefore no Overhead/Underground value can be determined.

For all premises where the Overhead/Underground or Commercial/Residential status could not be determined, these were deemed Unknowns. The Unknowns were distributed across all categories based on the ratio of the known premises. For example, if there were 100 Residential/Underground premises, 50 Commercial/Underground premises and 30 Unknown Underground Premises, the ratio of Residential to Commercial is 2 to 1, therefore 20 unknown premises were added to Residential and 10 premises were added to Commercial.

Reliability of information

The data used for determining the overall quantities has been provided previously and has been categorised based on assumptions and estimates. Caution should therefore be used when using this information for benchmarking or decision making purposes. The determination of Underground/Overhead is derived from the GIS where practical and WASP where it wasn't. The assumptions were made in the best effort to optimise the information at Essential Energy's disposal without compromising the reliability of the figures.

Financial Expenditure

This is based on the standard methodology adopted for all finance expenditure data in the Reset RIN. Refer to section 1.8 for the standard methodology adopted.

Distribution Substations Installed – 08/09 to 12/13 for Residential/Commercial and Subdivision Connections

Compliance with requirements of the notice

The Notice requires the number, total MVA and cost of distribution transformers installed split by Rural, Commercial/Industrial and Subdivision for each financial year from 08/09 to 12/13. The information has been determined using extracts from WASP where Essential Energy has contributed to a project where a transformer was installed. Smallworld and Energy are used to determine the percentage of premises affected by the project that are Residential/Commercial.

Source of information

Energy/Peace

- Premise with Residential/Commercial flag.

Smallworld

- Return premises supplied by substations affected by projects reported from WASP.

WASP

- List of projects where Essential Energy has financially contributed to the installation of a transformer during the reporting period. Extract included kVA, number of transformers, total Essential Energy cost for the project and project completion date.
- List of projects partially funded by a customer during the reporting period.

Planning Database

- List of customer initiated projects.
- Estimated unit costs for transformers based on OH/UG and kVA. Costing included estimated man hours.

Methodology and Assumptions

The list of projects from the planning database combined with the customer funded projects from WASP make up the considered projects for these figures. For these projects WASP is used to determine if Essential Energy or an external party paid for the transformer.

For each project, a ratio of Residential to Commercial premises affected by the project was assigned. This ratio was then used to determine the portion of the kVA, number of transformers and costs that would be reported as Residential and Commercial. Total cost is an estimate of the cost to install the transformers plus the estimated man hours to install.

For all projects where the Commercial\Residential status could not be determined, these were deemed Unknowns. The Unknowns were distributed across all categories based on the ratio of the known projects.

Assumptions

- The ratio of known projects is the same as the ratio of unknown projects.
- Residential/Commercial status of a premise has not changed during the reporting period.
- Essential Energy has no Subdivision assets based on the definition "is intended to capture expenditure in connecting un-reticulated lots or areas."

Use of estimated information

Essential Energy has used estimated information for projects where Residential/Commercial could not be determined.

An estimate was required in the following cases:

- No premises with a valid Residential/Commercial status could be found.
- The project was not found in Smallworld.

For all projects where the Commercial\Residential status could not be determined, these were deemed Unknowns. The Unknowns were distributed across all categories based on the ratio of the known premises. For example, if the MVA of the Residential projects was 100, MVA of the Commercial projects was 50 and MVA of the Unknown projects was 30, the ratio of Residential to Commercial is 2 to 1, therefore 20 Unknown MVA were added to Residential and 10 MVA were added to Commercial.

Reliability of information

The data used for determining the quantities has come from three major Essential Energy repositories where the data is considered reasonably reliable. There were a number of projects that didn't exist in Smallworld which had to be averaged, based on assumptions and estimates. This information should be used with caution for benchmarking or decision making purposes.

The assumptions were made in the best effort to optimise the information at Essential Energy's disposal without compromising the reliability of the figures.

Financial Expenditure

This is based on the standard methodology adopted for all finance expenditure data in the Reset RIN. Refer to the Repex and Augex data basis of preparation for examples of the standard methodology adopted.

Augmentation HV LV – 08/09 to 12/13 for Residential/Commercial and Subdivision Connections

Compliance with requirements of the notice

The Notice requires the total length of HV and LV augmentation split by Residential, Commercial/Industrial and Subdivision for each financial year from 08/09 to 12/13. The information has been determined using extracts from WASP where Essential Energy has contributed to a project. Smallworld and Energy are used to determine the amount of network augmentation and the percentage of premises affected by the project that are Residential/Commercial.

Source of information

Energy/Peace

- Premise with Residential/Commercial flag.

Smallworld

- Return premises supplied by substations affected by projects reported from WASP.

WASP

- List of projects where Essential Energy has financially contributed to the reporting period.
- List of projects partially funded by a customer during the reporting period.

Planning Database

- List of customer initiated projects.

Methodology and Assumptions

The list of projects from the planning database combined with the customer funded projects from WASP make up the considered projects for these figures.

For each project, Smallworld provided the amount of network added or re-conductored as a part of the project. A ratio of Residential to Commercial premises affected by the project was also assigned. This ratio was then used to determine the portion of the line length that would be reported as Residential and Commercial.

For all projects where the Commercial/Residential status could not be determined, these were deemed Unknown. The Unknowns were distributed across all categories based on the ratio of the known projects.

Assumptions

- The ratio of known projects is the same as the ratio of unknown projects.
- Residential/Commercial status of a premise has not changed during the reporting period.
- Essential Energy has no Subdivision assets based on the definition "is intended to capture expenditure in connecting un-reticulated lots or areas."

Use of estimated information

Essential Energy has used estimated information for projects where Residential/Commercial could not be determined.

An estimate was required in the following cases:

- No premises with a valid Residential/Commercial status could be found in Smallworld.
- The project was not found in Smallworld.

For all projects where the Commercial\Residential status could not be determined, these were deemed Unknowns. The Unknowns were distributed across all categories based on the ratio of the known premises. For example, if the line length of the Residential projects was 100km, line length of the Commercial projects was 50km and line length of the Unknown projects was 30km, the ratio of Residential to Commercial is 2 to 1, therefore 20 km's were added to Residential and 10 km's were added to Commercial.

Reliability of information

The data used for determining the quantities has come from three major Essential Energy repositories where the data is considered reasonably reliable. There were a number of projects that didn't exist in Smallworld which had to be averaged based on assumptions and estimates. This information should be used with caution for benchmarking or decision making purposes. Additionally, the network augmentation data captured in Smallworld prior to 2011 is incomplete and should be considered to be unreliable.

The assumptions were made in the best effort to optimise the information at Essential Energy's disposal without compromising the reliability of the figures.

Financial Expenditure

This is based on the standard methodology adopted for all finance expenditure data in the Reset RIN. Refer to the Repex and Augex data basis of preparation for examples of the standard methodology adopted.

2.5.1 & 2.5.2 Descriptor & Cost Metrics for Embedded Generation – 08/09 to 12/13

Compliance with requirements of the notice

The Notice requires the total number of embedded generation sites supplied by overhead/underground along with the total number of projects undertaken by Essential Energy to augment the network to facilitate the installation of embedded generation sites. These projects are broken down into MVA added, number of substations installed, HV augmentation and LV Augmentation.

Source of information

Energy/Peace

- Premise with Residential/Commercial flag.
- All embedded generation sites with Application Date and Installation Date.

Reporting Database

- All embedded generation projects completed by Essential Energy in the reporting period.

Methodology and Assumptions

Overall

The Energy embedded generation data was used as the basis for this data. Where installation date was blank, application date was used.

Overhead/Underground Totals

Residential/Commercial flag was derived from energy. For all embedded generations where the Residential/Commercial status could not be determined were deemed Unknown. The Unknowns were distributed across all categories based on the ratio of the known embedded generations.

Assumptions

- The ratio of known embedded generation is the same as the ratio of unknown embedded generation.
- Embedded generation with no installed date were installed in the same financial year as the application date.
- Residential/Commercial status of a premise has not changed during the reporting period.

Use of estimated information

Essential Energy has used estimated information for embedded generation where Residential/Commercial could not be determined.

An estimate was required in the following cases:

- Residential/Commercial status could not be assigned.

For all embedded generation where the Commercial/Residential status could not be determined, these were deemed Unknowns. The Unknowns were distributed across all categories based on the ratio of the known premises.

Reliability of information

The data used for determining the figures has come primarily from Energy but prior to existing in Energy, data from a number of disparate sources. The nature of the solar data is known to have issues. This information should be used with caution for benchmarking or decision making purposes.

The assumptions were made in the best effort to optimise the information at Essential Energy's disposal without compromising the reliability of the figures.

Financial Expenditure

This is based on the standard methodology adopted for all finance expenditure data in the Reset RIN. Refer to the Repex and Augex data basis of preparation for examples of the standard methodology adopted.

2.5.2 – Cost metrics by connection classification– Simple/Complex Connections– 08/09 to 12/13

For Residential/Commercial and Subdivision Connections

Compliance with requirements of the notice

The Notice requires the total number of embedded generation sites supplied by overhead/underground along with the total number of projects undertaken by Essential Energy to augment the network to facilitate the installation of embedded generation sites. These projects are broken down into MVA added, number of substations installed, HV augmentation and LV Augmentation.

Source of information

<u>Energy/Peace</u>

- Premise with Residential/Commercial flag and start date.

<u>Smallworld</u>

- Premise/Service Point Spatial Data
- Cable/Service Spatial Data

Methodology and Assumptions

In Smallworld, a service point has a spatial location and is connected to the network by a piece of service cable. A service point can have 1 or many premises attached to it.

Each premise was attributed with the Connection Complexity of the Service Cable that was either connected to or near the Service Point. If no service cable was attributed, the premise was assumed to be simple.

The Connection Complexity of the Service Cable in the GIS were determined as either simple or complex as per the definitions in Appendix G of the RIN instructions document for both Residential, Commercial and Industrial types.

The year the service was installed was assigned by the premises start date from Energy.

Assumptions

- Residential/Commercial status of a premise has not changed during the reporting period.
- All commercial services are simple services.

Use of estimated information

Not applicable

Reliability of information

The data used for determining the overall quantities has been provided previously and has been categorised based on assumptions and estimates. Caution should therefore be used when using this information for benchmarking or decision making purposes. Smallworld GIS was used to determine the split between simple and complex connections.

Financial Expenditure

This is based on the standard methodology adopted for all finance expenditure data in the Reset RIN. Refer to the Repex and Augex data basis of preparation for examples of the standard methodology adopted.

Worksheet 2.6 – Non Network Expenditure

2.6.1 – Non network expenditure

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Motor vehicles – Opex: Data originally sourced from PeopleSoft to get total recoveries and was confirmed through a 2013 RIN report that utilised fleet recovery costs for each year back to 2007. These figures were adjusted to get the total recoveries relating to the regulated network business. Figures were then mapped to the RIN categories based on PeopleSoft project type data splits where available. Where these were not available, the allocation basis from the previous years' figures was used. For 2014, the PeopleSoft figures were prorated from the nine months to March. A percentage of 97.1% was applied to get the regulated network total recovery figure. The 2012 allocation percentage for the RIN category splits was then applied to the 2014 total regulated network recovery figure to break down the costs into the correct categories.
- Motor vehicles – Capex: Total Capex for historical years was obtained from the previous annual regulatory accounts. For 2009 – 2011, PeopleSoft project type data was used to split costs into the relevant categories. For 2012 – 2013, a Project for Non System Regulated Distribution Capex (PNSRDC) report was utilised to allocate the regulatory account figures into the RIN categories. For 2014, the Non System Regulated Distribution Capex (NSRDC) figure was prorated out for the full year. This was then split out into the RIN categories using the 2013 allocation split.
- Motor vehicles' capex and opex categories relating to trailers and other fleet are not included in the RIN categories but have been used to reconcile to the total in the regulatory accounts.
- Buildings and Property – Opex: Historic data was sourced from worksheets attached to audited regulatory accounts for each year (2009 – 2013). 2014 data is prorated off PeopleSoft data for Property Management.
- Buildings and Property – Capex: Historic data was sourced from the audited regulatory accounts for each year (2009 – 2013). 2014 data is extrapolated from NSRDC year to date February report.
- Furniture and fittings capex: Historic data was sourced from the audited regulatory accounts for each year (2009 – 2013). 2014 data is extrapolated from NSRDC year to date February report.
- ICT opex: Historic data was sourced from PeopleSoft. In the regulatory accounts, ICT opex is broken down into two elements. The first being the recharge element (which matches with the RIN category client device expenditure) and the second being the balance of ICT charges. This first element, recharges, is incorporated in all the overheads of the business by virtue of the recharge system. The second element, balance of ICT charges, is also allocated to overheads and can be located in regulatory accounts table 9.1 each year. The recharge element is calculated by taking the PeopleSoft recharge proportions and multiplying it by the network regulated business percentages. This figure is then used to input table 2.6.1 for client device expenditure. The balance of ICT charges is proportioned into recurrent and non recurrent based on mapping provided by the ICT department. 2014 data is based on the Q3 forecast.
- ICT capex: Historic data was sourced from the regulatory accounts and mapped to the RIN based on ICT mapping data.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

2.6.2 Annual descriptor metrics – IT & Communications expenditure

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

Information was gathered from several sources, namely:

- Employee Numbers: have been provided by the Essential Energy AER team.
- Historical Regulated employee numbers have been sourced from the Regulatory accounts and have been arrived at by summing the product of the total number of FTEs in each department by the percentage allocated to the regulated network business.
- User Numbers: derived from an extract from ICT's Configuration Management Database (CMDB) as at 31 December annually, based on individual users who had one or more assets assigned to them.
- Number of Devices: derived from an extract from ICT's Configuration Management Database (CMDB) as at 31 December annually.

Methodology and Assumptions

The following assumptions have been made when compiling this data:

1. Employee Numbers: Historical
   - Based on the data provided by the Essential AER team
2. User Numbers: Historical
   - Consistent with the basis of estimating the number of Regulated Network Employees (ie 2008/09: 86.6%; 2009/10: 88.0%; 2010/11: 89.6%; 2011/12: 90.3%; 2012/13: 91.9%; 2013/14: 93.9% of total employees), the historical values are based on an overnight extract of employee numbers from PeopleSoft which is loaded to the ICT Configuration Management Database ('CMDB') and adjusted by the same percentage
   - For the period July 2008 through December 2012, device reports were issued monthly to individual users within Essential Energy with a request to confirm allocation of devices, and monthly charges were applied for these devices at a Cost Centre level. Post December 2012, the monthly reporting to individual users was discontinued, however the monthly charge to Cost Centres continued.

3. Device Numbers: Historical
   - The device numbers include laptops and desktops only.
   - The historical values are accurate based on the ICT CMDB. For the period July 2008 through December 2012, device reports were issued monthly to individual users within Essential Energy with a request to confirm allocation of devices, and monthly charges were applied for these devices at a Cost centre level. Post December 2012, the monthly reporting to individual users was discontinued, however the monthly charge to Cost Centres continued.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

Essential Energy advise that the historical employees information provided in this table is considered reliable.

Historical User and Device numbers are also based on assumed percentages of total user and device numbers so caution should be used when using this information for decision making or benchmarking purposes.

2.6.3 Annual descriptor metrics – Motor vehicles

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

Information was gathered from several sources, namely:

- PeopleSoft
- SGFleet
- LeasePlan

Methodology and Assumptions

The following assumptions have been made when compiling this data:

1. Employee Numbers: Historical
    - Based on the data provided by the Essential AER team
2. Non - motorised fleet have been excluded form table 2.6.3.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

Worksheet 2.7 – Vegetation Management

2.7.1 Descriptor metrics by zone

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

A map showing the vegetation management zones is provided in the Vegetation Management Asset Management plan - CEOM8018.15.

Source of information

Data was sourced from the following:

- WASP
- Essential Energy Vegetation Cost Model
- Field survey 2011/12
- Smallworld
- Sample of completed scoped vegetation maintenance areas in each Zone from the 12/13 maintenance program

Methodology and Assumptions

Route Length within Zone

Route lengths in each Zone are overhead route lengths only as underground route lengths were considered irrelevant from a vegetation management perspective. Route lengths are categorised using the following methodologies:

- If a span is LV only then it is 'LV'
- If a span is subtransmission only then it is 'subtrans';
- If a span is HV short rural & LV then it is short rural (Rural)
- If a span is HV long rural & LV then it is short rural (Rural)
- If a span is HV but doesn't have a category, assume it is rural and include it with the total short rural & long rural.

Zone totals are made up of the sum of the length of their depot areas.

Essential Energy has created separate ‘Zones’ for each of the above categories to ensure all the overhead network is accounted for.

Years prior to 2012/13 were calculated by using the percentage of the total route length for each Zone of each category.

Number of Maintenance Spans

The number of spans per Zone as per the above category definitions was sourced from the Smallworld system by depot area and then consolidated into their respective Zone.

The percentage vegetated is based on a sample of completed scoped vegetation maintenance areas in each Zone from the 12/13 maintenance program and split into rural and urban maintenance areas. The percentage is calculated by total defects reported in these maintenance areas divided by total poles in the maintenance area.

Total Length of Maintenance Spans

The total route lengths of each Zone (methodology outlined above) multiplied by the vegetated percentage of the network used in the 'Number of Maintenance Spans' metric above for each Zone.

Length of Vegetation Corridors

The percentage of the network was calculated using all rural vegetation maintenance areas that had maintenance carried out on them in 12/13. A maintenance area was considered to be a corridor if the work mix carried out in that area contained trimming and ground clearance work.

From this data it was deemed that 82% of the rural network was corridor and so this percentage was applied to the rural length of the network from the 'Route Length within Zone' metric.

Average number of trees per urban and CBD vegetation maintenance span

The vegetation density for all years is based on field survey data from the 2011/12 financial year. 30 vegetation maintenance areas were surveyed across the Essential Energy urban network with the sample made up of vegetation maintenance areas from each of the five vegetation maintenance Zones.

Average frequency of the cutting cycle

For the 2012/13 financial year the average cutting cycle is based on the total number of urban and rural vegetation maintenance areas that were completed divided by the total number of urban and rural areas.

For the 2011/12 and 2010/11 financial year the total number of vegetation maintenance areas completed was split using the 2012/13 urban/rural split for each Zone.

Prior to the 2010/11 financial year, Zone borders were different and/or vegetation management was regionally based so the planned 2 year rural, 1 year urban cycles have been used.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

Some of the information provided is based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

Some information provided for 2012/13 is considered reliable.

2.7.2 Expenditure metrics by zone

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Project type aerial patrol vegetation scoping was removed in 2013 as there was an allocation change agreed for the regulatory accounts. This totalled approximately $8,535,400.
- Geographical areas have been split from Zone 1 to Zone 6 via a mapping exercise i.e. from RIN categories to geographical zones.
- Service subcategories have been extracted out of PeopleSoft for each relevant year.
- Project types provided for the zone split were in a direct cost basis.
- Vegetation ops management, department 891, was proportionately allocated across zones 1 – 5. The regulatory direct costs were then proportioned across zones to reconcile back to the regulatory accounts.
- Service subcategory Audit – Split was a late calculation and was deducted from Inspection.

A list of the relevant regulations that govern Essential Energy's vegetation management activities is provided in Reset RIN Table 7.3.

A list of Essential Energy's internal vegetation management policies and procedures is provided in Reset RIN Table 7.1.

The cost impacts of these regulations, internal policies and procedures is provided in Tables 7.1 and 7.3.

Reliability of information

Most historical data is based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

2.7.3 Descriptor metrics across all zones – unplanned vegetation events

Compliance with requirements of the notice

Essential Energy does not hold any historical records to populate this table and as such the table has not been completed.

Worksheet 2.8 – Maintenance

2.8.1 Descriptor metrics for routine and non-routine maintenance

Compliance with requirements of the notice

The information provided is based on all assets owned by Essential Energy as well as privately owned assets where they are managed and maintained by Essential Energy.
Data has then been filtered to only include those assets that are "in service".

Source of information

Data has been sourced from the following:

- PeopleSoft Financial System
- Works, Assets, Solutions and People Database (WASP)
- Smallworld Geospatial Information System (GIS)
- Totalsafe Safety and Incident System (Totalsafe)
- Electricity Network Incident Failure Database (ENI)
- Electricity Networks Association Annual Pole Failure Reporting

Methodology and Assumptions

The asset quantity for most asset types is based on information from WASP and Smallworld GIS. The asset quantities for 2012/13 are considered reliable, but Essential Energy does not have the same level of confidence for asset quantity data for prior years. In addition, Essential Energy does not believe that the total number of assets, for some asset types, has changed significantly over the last 5 years. For these two reasons the asset quantities for some asset types in 2008/9 to 2011/12, have been set at the same level as the asset quantities in 2012/13.

Pole Top, Overhead line & Service Line Maintenance

Assets at year end are calculated as at March 2014 based on a WASP count. Assets are total poles (both distributor owned and distributor maintained private poles) and total service connection points (both overhead and underground) that are currently held in WASP.

This category provides a count of all corrective maintenance tasks that have been completed as operating expenditure outside the normal zone substation boundary fencing. The only exception is those tasks relating to underground, distribution substation or protection equipment assets, which are covered separately in the tables. Corrective tasks associated with services are separated and individually detailed as requested.

Accurate age data within the various asset systems is considered incomplete at best. For this reason current average age data has been assessed based on the best available data. It is assumed that historical replacement and growth rates have not been sufficient to suspend the average age of most assets ensuring a gradual increase in average age dependant on the individual asset. A basic calculation has been used to estimate the historical average age. Data for this algorithm is approximate and should not be used as accurate.

Pole Inspection and Treatment

Assets at year end are calculated as at March 2014 based on a WASP count. Assets are total poles both distributor owned and distributor maintained private poles.

Assets inspected include all WASP pole inspection tasks that were completed for the respective years. Each task includes the required activities based on pole age and condition. This may include excavation, drilling, visual inspection and routine treatment of decay or termites.

Overhead Asset Inspection

Assets at year end are taken from the Smallworld GIS system and cover the total route length of the overhead network. As all overhead assets are inspected during the 4 year asset inspection cycle, yearly assets inspected are described as kilometres of route length covered by the asset inspector each year. This will include visual inspection of conductor, crossarm, insulators, transformers, and other overhead equipment.

Average age is based on assumed conductor age and the maintenance cycle is assumed to be the inspection cycle as required corrective maintenance is normally carried out within 6 months of inspection.

Network Underground Cable Maintenance: By Voltage

Assets at year end are taken from the Smallworld GIS system and cover the total route length of the underground network. The total route length does not include underground services as these are generally maintained by the customer. Total asset data is recorded in thousands of kilometres and grouped by the requested voltage split.

Assets maintained includes all corrective work tasks involving underground assets that were recorded and completed in the respective year, then grouped by voltage. Defective work tasks are also displayed in thousands.

The maintenance cycle is shown as 4 years to correspond with the inspection cycle. Although work tasks are prioritised to various timeframes for completion, the lodgement and scheduling is performed in conjunction with the inspection.

Network Underground Cable Maintenance: By Location

Assets at year end are taken from the Smallworld GIS system and cover the total route length of the underground network. The total route length does not include underground services as these are generally maintained by the customer. Total asset data is recorded in thousands of kilometres and grouped by the requested location. As Essential Energy does not have any feeders in the CBD category all data has been grouped into the Non-CBD area.

Assets maintained includes all corrective work tasks involving underground assets that were recorded and completed in the respective year. Defective work tasks are also displayed in thousands.

The maintenance cycle is shown as 4 years to correspond with the inspection cycle. Although work tasks are prioritised to various timeframes for completion, the lodgement and scheduling is performed in conjunction with the inspection.

Distribution Substation Equipment & Property Maintenance

Assets at year end in this category include all distribution substation transformers (both overhead and enclosed). Where actual substation switch information was not available, a consistent algorithm was used to assess the number. This allowed 2.5 switches per overhead substation and 6 switches per enclosed substation. This conservative assumption was based on 1 high voltage switch and an average of 1.5 low voltage units per overhead substation, while enclosed substations allowed for 2 high voltage switches and 4 low voltage units.

The only "Other Equipment" captured was based on individual regulating transformer units and population data for substation property is based on the total distribution substation sites held in WASP. Due to data accuracy relating to past years the totals are shown to be consistent over the 5 year period.

All corrective tasks associated with substation sites that do not relate specifically to either switches or regulators are displayed in the "Distribution Substation Transformers" line item. Both switch and regulator tasks are grouped in their respective line items. No tasks have been shown relating to property.

Protection Systems Maintenance

Maintenance tasks are those tasks directly related to maintaining distribution recloser sites and are taken from WASP. As the visual inspection cycle for these assets is performed annually, the maintenance cycle is also assumed to be annual.

Other Inspection Programs

All other routine inspection programs are itemised within this group. These WASP work tasks have not been included in any other category and are broken up as follows;

Pit and Pillar Inspection: Population includes all underground pits and pillars (HV and LV) that are routinely inspected for safety and performance defects. This program has been progressively ramping up as resource constraints allowed and will be reviewed for cycle duration after a complete cycle.

Critical Equipment Inspection: This program is also in its early stages and follows a risk based approach. It allows for a targeted group of critical assets including major distribution substations, to be highlighted and closely inspected every year. The inspection incorporates activities such as maximum demand reporting, partial discharge and thermovision detection, clearances and oil leaks. Approximately 1200 sites have been selected for an annual cycle. The average age of these assets is approximately 23 years.

Enclosed Substation Inspection: This is a four yearly intensive inspection program that allows isolation of kiosk, chamber and ground-mount substations that cannot be adequately assessed by regular asset inspection practices. A relatively consistent population of 6091 with an average age of 17 years has been assumed. Inspected units vary each year due to specific scheduling constraints but an overall cycle of 4 years is assumed.

Annual Thermovision Inspection: A detailed thermovision inspection of targeted urban high voltage network is completed each year. Although accurate recording of completed inspections has been sporadic in the past, approximately 100,000 pole top connections are assessed annually. Inspection numbers documented in the table are taken from WASP but are considered unreliable due to past reporting issues. Average age of the specific assets is assumed to be 32 years.

Annual Regulator and Recloser Inspection: This program has historically ensured a detailed 6-monthly inspection of all distribution reclosers and regulators. The program was recently reviewed with regard to current constraints and modified to only include those assets that are not connected to remote communication facilities and performed annually. The combined average age of these assets has been assessed as 15 years.

Earth Integrity Testing: This 4 yearly program ensures the integrity of both high and low voltage earthing systems supporting those assets not available for the regular asset inspection program. Approximately 20,000 earth sites are tested over a 4 year cycle with an average age of 27 years.

Subtransmission Live Line Inspection: This program targets rural radial subtransmission feeders and allows for close approach pole top inspection using an elevating work platform and specialised live line practices. Approximately 36,000 poles are inspected over an 8 year cycle with an average age assumed to be 37 years.

Annual Fire Mitigation Inspection: This program is a scheduled aerial inspection of almost the entire rural network. A combination of fixed wing and helicopter based inspection will highlight any line defects that are potential bushfire risk issues. This can include targeted asset defects as well as selected vegetation incursions. Work tasks are then prioritised and scheduled for rectification prior to the designated bushfire season. Going forward this program will be managed within the vegetation budget.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

Data for 2012/13 is considered to be reasonably reliable. Prior to this, data is less accurate so caution should be used when using this for benchmarking or decision making purposes.

SCADA & Network Control Maintenance

Compliance with requirements of the notice

The information below relates to SCADA & Network Control Communications Network Assets only and is in accordance with that definition as provided by the AER. Note that there is a formatting issue for the zone substation assets row which appears to have nil values but actually contains quantities in the hundreds.

Source of information

Several systems and planning documents have been queried. These systems and documents are listed below along with the data sets obtained from those systems.

System	**Data set**
Primavera	Capital project data
Service Manager	Historic Asset Replacements/Asset Failure
Diagnostic Software	Historic & current radio asset data
ROE device list	Historic & current IP asset data

Methodology and Assumptions

Asset quantity at year end

Assets captured in this category are those which have a sole purpose of providing SCADA & Network Control functionality to Zone Sub Stations. Assets used to provide communication services to pole top devices has not been included in this section and will be captured elsewhere.

Asset quantity inspected/maintained

Essential Energy has included all assets in this category that have either been physically inspected or maintained via remote diagnostic systems. Many assets are not physically inspected but their condition is continually assessed via remote diagnostics software, alerting to any degradation in service or asset condition.

Average age of asset group

Data is based on year of purchase for the asset and averaged across all asset categories.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

<u>Public Lighting Maintenance</u>

Compliance with requirements of the notice

The information below relates to Public Lighting Maintenance Assets only and is in accordance with that definition as provided by the AER.

Source of information

Refer to Basis of Preparation for table 4.1.2.

There have been no depreciation periods calculated for each luminaire type as there were no tables to populate that related to Public Lighting.

The average age of the asset group was calculated, however the average replacement age of each of type of luminaire has not been calculated as there were no tables into which the data could be entered.

Methodology and Assumptions

Assets at Year End

Data was consolidated from individual Local Government Area (LGA) end of financial year asset inventory reports. These reports include all devices except metered and/or quarantined devices.

These devices were excluded for the following reasons:

- Quarantined lights do not contain enough information to determine the luminaire size.
- Metered lights are the responsibility of the owner for maintenance and replacement, and the energy consumption is not calculated using the Type7 Unmetered Billing System. As such not all metered lights have been captured in the WASP database.

The reports are generated through Cognos Report Studio using a materialised view created for the Streetlight Business Unit.

On 1/7/2013, 25 reports failed to generate. This was not realised until the commencement of this process. As it is not possible to retrieve counts of data for past dates, asset details were extracted from WASP on 10/2/2014 using Report Studio for the failed LGA reports.

Assets Inspected/Maintained
This number is the sum of all routine and non-routine streetlight maintenance tasks identified from data extracted for table 4.2.1. This number does not include pole inspections.

Average Age of Asset Group
The current average age of the streetlight asset group has been calculated as follows:

- All current in-service device details were extracted from the WASP database using Cognos Report Studio. Data extracted included luminaire type, asset id and date connected. Included in the extract was an expression to identify the number of days between the date connected date and the date of extract. For devices where there was no date connected, an assumption was made and the first recorded history record for the asset has been used.

- Data was then manually categorised as minor road and major road, and a formula was applied to identify the age in years by dividing the total age in days by 365. This calculation was performed for each individual asset.
- The data was pivoted to identify major road and minor road lights. The total number of years was divided by the total number of devices for both major road and minor road lights to arrive at two separate average ages.

2011/2012 average age was calculated as follows:

- 2012-2013 replacement devices x (assumed old average of 20 less assumed new average of 1) added to 2012-2013 total years divided by 2011/2012 devices.
- This calculation was then worked backwards for years 2010/2011, 2009/2010, 2008/2009.
- The assumed old average age was estimated at 20 as this was the expected life of luminaires, and the assumed new average age was estimated at 1.

Use of estimated information

As all information has been sourced from WASP and is considered to be actual data, no estimations have been made.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

Zone Substations

Compliance with requirements of the notice

The information below relates to Zone Substation Assets only and is in accordance with that definition as provided by the AER.

Source of information

Information was sourced directly or derived from WASP. In general, asset counts have been derived from the Asset Register and maintenance events from the work scheduling module.

Methodology and Assumptions

Asset counts:

- Asset Quantities for several categories have been reverse-estimated from relatively accurate 2012/13 figures and then assumed growth in parallel with circuit breakers (CB), for which better annual estimates back to 2008/2009 were known. CB numbers were taken from internal spread sheets which represent WASP data shapshots in mid-2008 & 2013 - 'Circuit Breaker Age Profile 2008.xls' & 'Circuit Breaker Age Profile April 2013.xls'. The numbers for the intervening years 08/09, 09/10, 10/11 & 11/12 were estimated assuming straight-line growth between these years. Assets handled like this were: Aux Tx's, Batteries/Chargers, Instrument Tx's, HV switches/disconnectors, Relays and Surge Diverters (33kV & above). NB: 2012/2013 figures for each of these smaller asset categories were for a service status of 'In Service' only. Protection Relay numbers – 6491 units, average age 19.7 years.
- 11/22kV surge diverters – the numbers entered represent the number of Zone Substation (ZS) sites where these units are present as indicated by the ZS Site asset attribute '11/22kV Surge Diverters Present'. It is NOT a count of the actual number of surge diverter units at these voltages, which is unknown.
- Asset counts for instrument transformers do NOT include indoor switchboard-mounted units.
- Tapchangers were assumed to parallel PTX growth (in numbers, NOT %).
- Growth in numbers of single-phase regulators & voltage regulation relays are assumed flat.
- Capacitor bank & indoor switchboard numbers – estimates derived from the Capacitor Register folder on Zone Substations 'G:' drive.
- The number of zone substation sites recorded represents the number of substations categorised in WASP as (Zone Substations + Subtransmission + Switching Stations) with a service status of 'In Service'. It also includes 6 x 66kv Regulator sites.

Maintenance event counts:

- Figures presented do NOT include oil sampling for any oil-filled device categories.
- Maintenance event counts have been derived from WASP data for each asset category for each year. The count has been carried out against Preventative Maintenance tasks only, with a task status of 'Closed'.
- The number of 11/22kV surge diverter maintenance events represents the number of substations where ALL 11/22kV surge diverters present were replaced. (Occurs on a 12-year cycle.)
- The number of ZS Site inspections represents the total number of inspections carried out during a calendar year. Substations are inspected at various frequencies, depending upon the level of remote monitoring equipment present at the site. Inspection frequencies are either monthly, every 2nd month, or every 3 months.
- Property maintenance is estimated to occur once every 4 years – records of this maintenance are not available at any single source and the maintenance is normally carried out on an ad-hoc basis in association with other maintenance categories – e.g. pest extermination, vegetation control, earthing system maintenance, site security issues etc.
- 'Inspection' of individual assets as such does not occur, but takes place indirectly as a component of the overall periodic ZS Site inspection regime applicable to any given zone substation, which occurs at various intervals as described above. The weighted average maintenance interval was calculated at 2.36 months.
- A number of asset categories have a variety of asset type/manufacturer specific maintenance intervals. Where this occurs, a weighted average maintenance interval was listed. E.g. Batteries, CBs, tapchangers.
- Indoor switchboard maintenance does not occur as a distinct event, but is driven by the maintenance interval associated with its component CBs.

Asset Ages:

- PTX average ages were calculated from WASP data dumps taken in June 2007 & January 2013, then interpolated for the years in between. PTX Service Status was filtered on 'In Service', 'Not Applicable', 'Out of Service', 'System Spare', 'Under Construction' and Under Repair'. Average ages for Surge Diverters (>=33kV), tapchangers & voltage regulation relays were estimated to be the same as these.
- CB average ages were estimated from WASP data. Average ages for Surge Diverters (<33kV) were estimated to be the same as these.
- Buildings were assumed to be the same average age as the Substation properties where they are located.
- Other minor asset category ages were reverse-estimated from 2013 averages.

Note that the zone substation numbers within the table appear as zero values due to formatting issues.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

The asset quantities for 2012/13 are considered reliable, but Essential Energy does not have the same level of confidence for asset quantity data for prior years. In addition, Essential Energy does not believe that the total number of assets, for some asset types, has changed significantly over the last 5 years. For these two reasons the asset quantities for some asset types in 2008/9 to 2011/12, have been set at the same level as the asset quantities in 2012/13. Caution should be taken when using this information for decision making or benchmarking purposes.

Expenditure allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

2.8.2 Cost metrics for routine and non-routine maintenance

Compliance with requirements of the notice

The information provided is based on all assets owned by Essential Energy as well as privately owned assets where they are managed and maintained by Essential Energy.
Data has then been filtered to only include those assets that are "in service".

As per the definitions provided all inspection activity expenditure has been included as "Routine Maintenance Costs" while all corrective maintenance expenditure is included in "Non-Routine Maintenance Costs".

Source of information

This data has been obtained from the following Essential Energy sources:

- Peoplesoft Financial System
- Working files provided by Essential Energy Finance team

Methodology and Assumptions

Pole Top, Overhead line & Service Line Maintenance
Financial data includes only the following project types;

- 11300 Overhead Mains M&R Rural
- 11305 Overhead Mains M&R Urban
- 11310 Overhead Mains M&R Subt
- 11340 Pole Nailing Rural
- 11345 Pole Nailing Urban

Due to specific expenditure data relating to services not being able to be separated, it is included in the one line item.

Pole Inspection and Treatment
Financial data for this category includes only the following project types;

- 11400 Pole Insp Treat & Audit Rural
- 11405 Pole Insp Treat & Audit Urban
- 11410 Pole Insp Treat & Audit ST

As the inspection of pole and other overhead assets is completed in the same program, the relevant expenditure is captured together. An assumption has been made to split this amount by the following ratio: 70% pole inspection and 30% overhead asset inspection.

Overhead Asset Inspection
Refer to the above item.

Network Underground Cable Maintenance: By Voltage
Financial data for this category includes only the following project types;

- 11315 Underground Mains Rural M&R
- 11320 Underground Mains Urban M&R

As the available financial data is not separated by voltage or location the total expenditure has been combined in one line.

Network Underground Cable Maintenance: By Location
Refer to the above item.

Protection Systems Maintenance
Financial data for distribution reclosers includes only the following project type;

- Reclosers/Regulators M&R

Unfortunately this account includes maintenance expenditure on regulators as well as reclosers and cannot be accurately separated. It is assumed that approximately 10% of the total would relate to regulator maintenance.

Other Inspection Programs
Expenditure for each of the following programs has been captured in the PeopleSoft financial system and based on the associated account lines.

- Pit and Pillar Inspection

11411 UG Pillar Inspections

- Critical Equipment Inspection

11415 Critical Asset Inspection

- Enclosed Substation Inspection

11445 Underground Asset Inspection
11450 Dist ST Inspection

- Annual Thermovision Inspection Urban

11425 Annual Thermo Inspection Urban

- Annual Regulator and Recloser Inspection

11430 Reg / Recloser Inspection

- Earth Integrity Testing

11447 OH Asset Earth Testing Urban
11448 OH Asset Earth Testing Rural

- Radial Subtransmission Live Line Inspection

11455 Radial Subtrans LL Inspection

- Annual Fire Mitigation Inspection

11420 Annual Fire Mit Insp Rural
11443 Aerial Patrol Veg Scoping

Use of estimated information

No estimated data has been provided. All data is directly from PeopleSoft financials.

Reliability of information

Maintenance expenditure at a total level aligns to the Regulated accounts, however the split into the various categories is based on assigning costs from Peoplesoft into the different categories, and management direction. Caution should be used when using this information for decision making or benchmarking purposes.

SCADA & Network Control Maintenance

Compliance with requirements of the notice

The information below relates to SCADA & Network Control Communications Network Assets only and is in accordance with that definition as provided by the AER.

Source of information

Several systems and planning documents have been queried. These systems and documents are listed below along with the data sets obtained from those systems.

System	**Data set**
PeopleSoft	Financial

Methodology and Assumptions

Routine maintenance

Costs associated with all planned maintenance activities on relevant assets have been included. Values provided are directly from PeopleSoft financials.

Data for the first 3 years (08/09 to 10/11) is assumed to be very inaccurate. This data relies on staff providing the correct codes on their timesheets for input to PeopleSoft. This process although present at the time was not robust leaving statistically large differences between years. Essential Energy is not able to provide a close estimate in the time required.

Non-Routine Maintenance

All costs associated with Non-Routine Maintenance (Unplanned failures) for relevant assets have been included. Values provided are directly from PeopleSoft financials.

Data for the first 3 years (08/09 to 10/11) is assumed to be very inaccurate. This data relies on staff providing the correct codes on their timesheets for input to PeopleSoft. This process although present at the time was not robust leaving statistically large differences between years. Essential Energy is not able to provide a close estimate in the time required.

Use of estimated information

All expenditure data is based on apportionment of totals in the Regulatory Accounts into the relevant category. Assumptions and estimates have been used to this this, so caution should be used when using this information for decision making or benchmarking purposes.

Reliability of information

All expenditure data is based on apportionment of totals in the Regulatory Accounts into the relevant category. Assumptions and estimates have been used to this this, so caution should be used when using this information for decision making or benchmarking purposes.

Cost data for non routine maintenance in the first 3 years (08/09 to 10/11) is considered to be unreliable and caution should be used when using this data for decision making or benchmarking purposes.

Public Lighting Maintenance

Compliance with requirements of the notice

The information below relates to Public Lighting Maintenance Assets only and is in accordance with that definition as provided by the AER.

Source of information

Refer to Basis of Preparation for table 4.1.2.

Methodology and Assumptions

This data is the sum of all material and labour (excluding pole) costs for all routine and non-routine maintenance. These numbers do not include any routine or non-routine replacement costs.

Use of estimated information

Not applicable as data provided has been derived from previously populated tables for actuals only.

Reliability of information

All expenditure data is based on apportionment of totals in the Regulatory Accounts into the relevant category. Assumptions and estimates have been used to this this, so caution should be used when using this information for decision making or benchmarking purposes.

Zone Substations

Compliance with requirements of the notice

The information below relates to Zone Substation assets only and is in accordance with that definition as provided by the AER.

Source of information

Data has been sourced from the following:

- PeopleSoft
- WASP

Methodology and Assumptions

With the exception of Protection Systems, routine and non-routine maintenance costs for other Zone Substation assets are not held in the Essential Energy financial system (PeopleSoft) in any form readily categorised. The figures presented are derived from totals in PeopleSoft and proportioned using summated work task duration estimates from WASP for the 2012/2013 year. These have then been extended across the earlier years.

Note that 2012/2013 was chosen as a representative year as it has a more complete and accurate record of non-routine maintenance than earlier years.

Power transformers have been extracted as a separate item, representing 9.2% of the overall routine maintenance hours and 16.4% of the non-routine maintenance for the 2012/2013 year. Building maintenance has also been extracted from WASP work task data on the same basis – (there is no routine maintenance tasks carried out on buildings and non-routine maintenance represents 0.6% of the annual total). PeopleSoft data relating to Protection Systems Maintenance is viewed as unreliable (e.g. there is no information for non-routine protection systems maintenance), so the figures presented have also been derived on the same basis as power transformers & buildings as described above.

Use of estimated information

Refer to methodology and assumptions section above.

Reliability of information

All expenditure data is based on apportionment of totals in the Regulatory Accounts into the relevant category. Assumptions and estimates have been used to this this, so caution should be used when using this information for decision making or benchmarking purposes.

All other asset categories

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Source of data is from master splits for RIN templates workpaper. Figures have been pulled from sub categories in the regulatory accounts.
- Dollars have been split between non routine and routine maintenance. The proportional split has then been used to reconcile back to the regulatory accounts.
- PeopleSoft was used to split projects into non routine and routine maintenance

Reliability of information

All expenditure data is based on apportionment of totals in the Regulatory Accounts into the relevant category. Assumptions and estimates have been used to this this, so caution should be used when using this information for decision making or benchmarking purposes.

Worksheet 2.9 – Emergency Response

2.9.1 Emergency response expenditure

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

Data has been sourced from:

- PeopleSoft Query - CE_PC_RES_BY_PROJECT_BY_T3
- Chart of Accounts with COA Mapping – Essentialnet

Methodology and Assumptions

- Total F&E costs were sourced from the Regulatory Accounts
- Cross checked coding with regulatory accounts to ensure consistent approach.
- Major Events Days Costs are based on Day of incident and two days after incident as major event days would usually take longer than a 24-48 hour period to resolve.
- Any costs allocated to F&E that was a capital transaction was excluded as a majority of these are negative amounts and have a minimal impact across each year – 12-13 FY had -$39k.
- In the regulatory accounts a $5m adjustment was made due to negative unknowns, this has been applied to the 12-13 FY results and are apportioned across all cost categories.
- Information provided for 08-09 Financial Year has been calculated differently due to a change in the Chart of Accounts that occurred on 1 July 2009. For information provided after 1 July 2009 Essential Energy have utilised GL Account numbers to align with the regulatory accounts. Essential Energy was unable to utilise GL Account numbers prior to 1 July 2009 due to a general project expense GL account number being used (GL # 21400) which was removed at the change in account numbers.

Use of estimated information

- Costs associated with a major event day is assumed to be for two days after the event as major event days would usually take longer than a 24-48 hour period to resolve.

Reliability of information

Expenditure at a total level is considered reliable.

Allocating costs to specific Major Event Days is dependent on allocations performed on historical data based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

Worksheet 2.10 – Overheads

2.10.1 Network overheads expenditure

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this line in the table are outlined below.

Essential Energy capitalises a component of its overhead expenditure. Capitalisation of overheads is governed by CEOP2416 – Operational Procedure: Asset Capitalisation, Section 4.

There have been no material changes in capitalisation policy over the review period.

Source of information

- Master file of financial data prepared as described in section 1.8.
- Cognos dataset of Operating Expenditure has been extracted and reconciled to relevant management accounts to ensure its validity.

Methodology and Assumptions

Aggregate Network Overheads

- Overheads were split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories, as described in section 1.8.

Disaggregation of Aggregate Network Overheads

- An estimate of the 'Indirect Cost Pool' for respective years was derived from Operating Expenditure through application of management accounting "Direct/Indirect" cost category logic.
- The estimated 'Indirect Cost Pool' was further split into Network Overhead and Corporate Overhead category's through application of management accounting "Direct/Indirect" cost category logic.
- Departments were allocated to the mandatory and discretionary categories disclosed within the table. This is based in their current primary functions applied consistently across all years. No adjustments have been made at a transactional level for data anomalies such as department 'splits' or costs coded to divisional management departments relating generically across the divisional structures.
- Aggregate Overheads were allocated across the mandatory and discretionary categories disclosed within the table proportionately based on the Total Network Overhead and Total Corporate Overhead estimated 'Indirect Cost Pool's' respectively.
- Aggregate Overheads for 2009 were allocated based on the 2010 financial year 'actuals' financial year proportional splits.
- For financial years 2009 to 2014, overheads were not allocated to 'Alternative Control' on the basis that no split was required prior to the 2015 financial year.

Use of estimated information

All forecast overhead data is estimated.

Reliability of information

Allocations between direct and indirect expenditure performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes. All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

2.10.2 Corporate overheads expenditure

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this line in the table are outlined below.

Source of information

- Master file of financial data prepared as described in section 1.8.
- Cognos dataset of Operating Expenditure has been extracted and reconciled to relevant management accounts to ensure its validity.

Methodology and Assumptions

Aggregate Network Overheads

- Overheads were split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories, as described in section 1.8.

Disaggregation of Aggregate Network Overheads

- An estimate of the 'Indirect Cost Pool' for respective years was derived from Operating Expenditure through application of management accounting "Direct/Indirect" cost category logic.
- The estimated 'Indirect Cost Pool' was further split into Network Overhead and Corporate Overhead category's through application of management accounting "Direct/Indirect" cost category logic.
- Departments were allocated to the mandatory and discretionary categories disclosed within the table. This is based in their current primary functions applied consistently across all years. No adjustments have been made at a transactional level for data anomalies such as department 'splits' or costs coded to divisional management departments relating generically across the divisional structures.
- Aggregate Overheads were allocated across the mandatory and discretionary categories disclosed within the table proportionately based on the Total Network Overhead and Total Corporate Overhead estimated 'Indirect Cost Pool's' respectively.
- Aggregate Overheads for 2009 were allocated based on the 2010 financial year 'actuals' financial year proportional splits.
- For financial years 2009 to 2014, overheads were not allocated to 'Alternative Control' on the basis that no split was required prior to the 2015 financial year.

Use of estimated information

All forecast overhead data is estimated.

Reliability of information

Allocations between direct and indirect expenditure performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes. All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 2.11 – Labour

2.11.1 Cost metrics per annum

ASL's

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

Data has been sourced from:

- PeopleSoft – HR module for years 2008/09 until 2012/13 as well as previous years' RIN allocation work papers.
- Cognos cubes from the Finance system have also been utilised
- The Dashboard for April 2014 from Human Resources was used as well as the Essential Energy pay register April 2014

Methodology and Assumptions

The HR data extracted from PeopleSoft represents all Essential Energy FTE employees including those from gas, retail and water.

The HR data also contained employee numbers by business department. For example, CORP&CS and CUST&CA. Essential Energy has categorised each business department into four further categories for the purposes of being able to meet the AER's reporting requirements:

1. Corporate
2. Network Overheads
3. Network Direct
4. N/A

Employee numbers relating to the Board have been excluded from the FTE numbers. A reconciliation was performed on this table to ensure employee numbers totalled back to the total employee numbers extracted from PeopleSoft for each year in question.

Essential Energy's job classifications were not the same as those requested by the AER. The alignment of Essential Energy's job classifications to the AER's job classifications was performed manually by matching job descriptions and making certain assumptions. Essential Energy noted the following assumptions:

- Employees categorised as "Technical", "Trades" or "Skilled Electrical" in the Corporate business department fell into the "Professional" employee category.
- Employees categorised as "Non Trade" or "Unskilled Worker" in the Corporate business department fell into the "Semi Professional" employee category.
- Employees categorised as "Admin" or "Support" in the Corporate business department fell into the "Support staff" employee category.
- Employees categorised as "Apprentice" in the Network Overheads business department fell into the "Intern, Junior Staff, Apprentice" employee category.
- Employees categorised as "Technical" or "Trades" in the Network Direct business department fell into the "Skilled Electrical Worker" employee category.
- Employees categorised as "Admin", "Support" or "Professional" in the Network Direct business department fell into the "Skilled Non Electrical Worker" employee category.

<u>Average Staffing Levels (ASL's)</u>

To ensure alignment and consistency with the employee numbers provided in table 2.6.2 (Annual Descriptor Metrics - IT & Communications Expenditure), Essential Energy has apportioned the employee numbers by job classification for each year in question. This has been performed by dividing the employee numbers for each job classification by the total employee numbers (excluding Board employees) and multiplying it by the total employee numbers in table 2.6.2 for each year from 2008/09 to 2012/13.

For 2013/14, the previous year's employee numbers by job classification in table 2.11.1 (2012/13) was used as a base and multiplied by table 2.6.2 current year employee numbers (2013/14) divided by the previous years' employee numbers (2012/13).

Total Labour Cost

1. The HR dashboard data was matched to the Pay register data using employee ID. This provided a split of employee job family and their associated costs.
2. This data was pivoted to produce an April 2014 split of staff numbers and payroll costs. The split of payroll costs by job family as a percentage of total payroll costs was then established.
3. The job family data was then aligned to the RIN classifications. Some classifications were straight one-for-one and others required splitting. The table below indicates how the job family data was aligned to the major RIN classifications:

Job family	RIN classification
Admin	Support staff
Management	Executive manager
	Senior manager
	Manager
Non Trade	Intern, junior staff, apprentice
Prof Spec	Professional
Technical	Professional
Trades	Semi professional

4. The split of management costs between the three different RIN classification categories was completed using the Management Classification Split file. This compiled job family with position description. After removing anomalies, managers could then be grouped into the three required categories based on title and pay rate.
5. An additional split was required to extract the Network Direct cost categories used in the RIN. The following four classifications required additional separation into the eight categories shown below:

RIN classification	Network & Corporate OHDs RIN classification	Direct Network Costs RIN classification
Intern, junior staff, apprentice	Intern, junior staff, apprentice	Apprentice
Professional	Professional	Skilled non electrical worker
Semi professional	Semi-professional	Skilled electrical worker
Support staff	Support staff	Unskilled worker

6. The results of these steps were summarised into a final cost split by the RIN classifications in the table above. This took the cost weighting for 2014 into account and the total ASLs.
7. The labour cost component of corporate overheads, network overheads and direct network costs was then extracted from the Cognos cubes.

8. Using the ASLs for each component, the derived percentage of costs derived in step 4 above and the labour costs from step 7, the final labour costs for each RIN classification could be established.
9. The Employee and Labour Hire splits on the 2.11 Labour sheet were used to apportion the costs between the two lines. i.e. It is assumed that employees and Labour hire have the same costs.

<u>Average productive work hours per ASL</u>

It is assumed that Corporate and Network support labour that is not coded to a project is all productive time as hours are not captured for non-timesheet employees in Peoplesoft. These staff do not report time against projects so the total hours for the Corporate and Network divisions from the “Labour with no project (MGT cube)” was considered to be productive labour hours; the productive hours for these ASL’s are assumed to be the available hours calculated each year for budgeting purposes. Available hours are calculated on the basis of total annual hours less annual, long-service sick and other leave components.

Additional productive time for networks support was taken from the Network Support hour’s project cube.

Direct network labour hours were taken from the Project cube in Cognos. These are hours directly related to projects and are therefore considered productive.

The productive hours per ASL was then calculated by apportioning the relevant total productive hours by the split of ASL staff for that category.

<u>Stand-down occurrences per ASL</u>

Data has been sourced from PeopleSoft – HR module for years 2008/09 until 2012/13.
Analysis was performed to determine the following:

1. In scope data based on department descriptions and reporting units
2. Labour categories based on reporting units
3. Labour classifications based on position titles

A pivot table was created to summarise count data from 2009 to 2014 into the types of labour costs (e.g. corporate overheads) and labour classification levels (e.g. professional or semi-professional staff).

FY14 was prorated by taking the previous year’s figures, multiplied by 12 and dividing by 9.5.
Stand – down occurrences per ASL is calculated by taking the ASLs for each year and dividing it by the number of stand – down occurrences in the relevant year.

Use of estimated information

Refer to methodology and assumptions section above. All forecast information is considered to be estimated.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes. All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

2.11.2 Extra descriptor metrics for current year

Compliance with requirements of the notice

Information provided as per completed template per AER instructions.

Source of information

- Project Labour hours - Opex and Capex (excludes Water and Gas but includes - Public lighting and generation) Cognos cube
- Non-project labour (excluding Water, Gas, Retail, but includes Public lighting & Generation) - by Dept tree specific to each year Cognos cube
- Project Labour $ Split Ordinary and Overtime- Opex and Capex Cognos cube

Methodology and Assumptions

Several assumptions have been made and are described in the steps below.

1. The Project Labour hours - Opex and Capex Cognos cube was run. This provided a split between overtime and ordinary hours for direct network labour costs and networks overheads labour costs.
2. Corporate overheads labour costs are all considered to be ordinary time as these staff do not generally receive overtime.
3. The overtime hours for each labour category were derived from the cube and apportioned using the 2014 calculated ASL numbers. These were linked to the relevant column in the 2.11 labour sheet
4. The average productive work hours per ASL – Ordinary Time could then be calculated by taking the Average productive work hours per ASL and deducting the Average productive work hours per ASL – Overtime calculated above.
5. The project labour $ and non-project labour cubes were used to derive the total ordinary time labour costs by the three labour categories required.
6. These costs were then apportioned using the 2014 average ASL levels for each category.
7. The derived costs could then be divided by the average productive work hours per ASL-ordinary time to give the average productive work hours hourly rate per ASL ordinary time.
8. The difference between the total labour cost per ASL category and the total overtime cost per ASL category could then be derived. This data was divided by the relevant average productive work hours per ASL – overtime to give the Average productive work hours hourly rate per ASL – overtime.

Use of estimated information

The information in the 2.11 Labour sheet is considered to all be estimated especially given the reliance on the derived ASLs and associated costs. Caution should be used when using this information for decision making or benchmarking purposes.

Further details regarding estimation are described in the Methodology and Assumptions section above.

Reliability of information

Essential Energy advise that this information provided in this section is all estimated and, therefore, is not considered to be one hundred percent reliable. Caution should be used when using this data for decision making or benchmarking purposes.

Worksheet 2.12 – Input Tables

2.12 Input tables

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Vegetation management was split into the requested cost categories using PeopleSoft project type data broken down into resource categories and zones.
- Routine maintenance was split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories.
- Non routine maintenance was split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories.
- Overheads were split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories. Overheads have been lumped into "Other" cost categories based on the time and resources available to dissect the data.
- Augmentation was sourced from previous regulatory accounts and split into the cost categories in line with historical PeopleSoft resource categories for each year.
- Connections were split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories.
- Emergency response sourced from table 2.9 of the Reset RIN templates. No major storms were noted for both historical and forecast data. There is also no forecast data for major event days.
- Public lighting was split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories.
- Metering was split into the requested cost categories using PeopleSoft project type data broken down into resource categories and RIN subcategories.
- Fee based and quoted services have been lumped into "Other" costs. Data was sourced from tables 4.3 and 4.4 of the Reset RIN templates.
- Replacements was sourced from previous regulatory accounts and split into the cost categories in line with historical PeopleSoft resource categories for each year.
- Non network expenditure has been lumped into "Other" costs. Data was sourced from table 2.6 of the Reset RIN template.
- All PeopleSoft data has been reconciled to the regulatory accounts.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 2.13 – Provisions

2.13.1 – 2.13.2 Changes in total provisions incl. RPM & Allocation of movement in total provisions incl. RPM

Compliance with requirements of the notice

This section contains data on provisions allocated to the Regulated Network business as shown in the respective year's regulatory returns, and includes information from the Q3 forecast in relation to 2014.

Financial information on provisions reconcile to the reported amounts for provisions in the Regulatory Accounting Statements for each Regulatory Year. Immaterial differences in opening and closing values were noted due to the rounding of numbers.

Source of information

Data has been sourced from work papers used in preparation of the statutory financial statements, and work papers used in preparation of the annual regulatory returns (IPART/AER), and data on the Q3 forecast for 2014 provision balances.

Methodology and Assumptions

The sign convention applied is consistent with the year-end regulatory return where provision values are expressed as negatives, with provision increases expressed also as negatives.

The methodologies applied to derive provision movements in the years prior to 2013 are consistent with those applied in the 2013 regulatory accounts. These include estimating the Regulated Network share of provision movements where the provision is not wholly related to the Regulated Network business. Prior to 2011 provision movements were not disclosed in the regulatory accounts.

In 2013 data on the defined benefit superannuation liability was included in Provisions in the statutory financial statements and regulatory statements, as opposed to Other Liabilities in previous years, as part of a Network NSW financial statement harmonisation process. Pre 2013 data has been provided on this item to be consistent with 2013.

The 2010 closing provision balances as per the 2010 regulatory accounts were inconsistent with the 2011 opening balance taken up in the AER regulatory accounts. For the purposes of this return the 2010 balances have been treated as per the 2011 opening balance. A reconciliation is available for this exercise.

The 2013 methodologies have been applied to the 2014 Q3 forecast information.

The assumption has been applied that a portion of the increase in employee related provisions (employee entitlements & worker's compensation) is apportioned to capital projects via the labour overhead process. No allowance has been made for any indirect form of capital allocation (E.g.: corporate allocation) of the operating expenditure component of these provisions. Another assumption underpinning the analysis is that material increases/ decreases to the Other Provision types have as a general rule been applied against the abnormal gain/loss account range. The abnormal gain/loss accounts have traditionally been excluded from the corporate allocation process and therefore would not give rise to a capital allocation.

The use of the abnormal account range was discontinued during 2014 with changes in other provisions being costed to operating expenditure accounts which could potentially be included in corporate allocations. It appears that based on the forecast data used there are no movements in other provisions that would possibly have an impact on corporate allocations due to either having no significant movement, or that the departments involved would be excluded from this process.

Note that in 2010 and previous years, the regulatory accounts did not include a provisions tab. Information gathered for these years is contained within provision movement working papers which ultimately feed back into the regulatory and statutory accounts.

Use of estimated information

- Essential Energy has used estimated information for the Regulated Network business' share of movements through employee provisions and defined benefit superannuation liability, the component of provision increases in the employee related provisions directly transferred to capital projects, and the break-up of the capitalised component across asset classes.

- Apportionment of the year end balances was done for the respective pre 2011 regulatory return, but a breakdown of movements was not required.

- An approach consistent with that applied in the 2011 to 2013 regulatory returns was adopted to derive the required movement data. This methodology has been subject to external audit in those years and was deemed appropriate for the prior years. On this basis, the approach has been replicated for the 2014 forecast data.

- Apportionment of the estimated labour component going to the asset classes included in table 2.13.2 was derived from analysis of the labour overheads going to internally funded project types across the years 2010 to 2014. This only relates to the direct transfer to capital and excludes any indirect transfer through another process such as corporate allocations.

Reliability of information

Data used for the initial provision tables has been sourced from work papers that support both the statutory accounts and the regulatory accounts for the respective years. Therefore the information provided is considered reasonably reliable subject to the assumptions discussed above.

The 2014 data has been sourced from work papers utilised in the Q3 forecast. All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 2.14 – Forecast Price Changes*

2.14.1 Forecast labour and materials price changes*

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

The information was obtained from a workbook provided by Competition Economics Group (CEG) on 20 December 2013 entitled 'Escalation Factors Essential Energy 20 Dec 2013.xlsm'.

Labour cost escalators were sourced from an Independent Economics Report.

Methodology and Assumptions

The methodology and assumptions behind the information provided can be found in the two reports below:

1. Independent Economics, *Labour cost escalators for NSW, the ACT and Tasmania*, 18 February 2014; and
2. CEG, *Escalation factors affecting expenditure forecasts*, December 2013.

Use of estimated information

Figures provided are based on the reports referenced above.

Reliability of information

The historical information was sourced from reputable third parties and is therefore considered reliable.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 2.15 – Commercial Insurance & Self-Insurance

2.15.1 Forecast commercial insurance premiums by risk category*

Compliance with requirements of the notice

The information provided in Table 2.15.1 is consistent with the requirements in the RIN. As required by paragraph 11.2(a) of Schedule 1 of the RIN, it provides a summary of all Essential Energy's current commercial insurance programs on which the proposed insurance costs are based. These costs exclude GST.

As required by paragraph 11.3 of Schedule 1 of the RIN, the following information is provided for each commercially insured risk listed in table 2.15.1:

(a) the name and description of each insured risk, including policy limits and sub-limits;
(b) a description of the general method used to forecast premiums (this may be in the form of an insurance premium forecast report by a qualified risk specialist). Refer response as to methodology below;
(c) No changes in cover between current and forecast. However policy limits, excess levels and extent of coverage are reviewed annually based upon updated risk information (including claims experience) and insurance market conditions which are cyclical.

Source of information

Essential Energy sourced information from internal records and insurance brokers, Aon and Marsh (risk specialists) whose reports provided premium/rate forecasts and past premiums.

Methodology and Assumptions

In accordance with paragraph 11.3 of Schedule 1 of the RIN, Essential Energy has forecast 2014-2019 premiums with input from our insurance brokers, Aon and Marsh, who have provided their rate/premium estimates factoring in the cyclical insurance market using our 2013-14 budget premiums as a base. Essential Energy has then increased property values to account for assets under construction, purchased or re-valued which will increase the replacement values used by insurers to calculate Essential Energy's property insurance premiums in addition to CPI. Please note that only 93.23% of total past and forecast property premiums have been included within table 2.15.1 and 2.15.2 as this equates to the percentage of written down value of the regulatory electricity network assets relative to total assets as at 2012/13 year end.

Bushfire risk continues to be a major issue for global insurers. Black Saturday and more recent Australian fires, particularly the October 2013 Blue Mountain bushfires, remain fresh in insurers' minds and could lead to significantly increased premiums.

Additional assumptions:

- No major bushfire losses in Australia;
- Claims generally consistent with past history;
- Deductibles remaining static;
- No significant change in risk profile;
- No limit changes;
- No global events which may impact the insurance market generally; and
- No changes to stamp duty or other government imposts.

Use of estimated information

Forecast estimates were required due to the cyclical and unpredictable nature of the insurance market.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.15.2 Insurance premium - Total property

Compliance with requirements of the notice

As required by paragraph 11.2(b) of Schedule 1 of the RIN, the information provided in Table 2.15.2 provides more detailed information regarding total property premiums only. The total property premiums forecast in table 2.15.2 equals the sum of the premium forecasts classed as property insurance in table 2.15.1.

Source of information

Essential Energy sourced information from internal records and insurance brokers, Marsh Pty Ltd (risk specialists) whose reports provided premium/rate forecasts and past premiums.

Methodology and Assumptions

In accordance with paragraph 11.3 of Schedule 1 of the RIN, Essential Energy has forecast 2014-2019 premiums with input from our insurance brokers, Marsh, who have provided their rate/premium estimates factoring in the cyclical insurance market using our 2013-14 budget premiums as a base. Essential Energy has then increased property values to account for assets under construction, purchased or re-valued which will increase the replacement values used by insurers to calculate Essential Energy's property insurance premiums in addition to CPI. Please note that only 93.23% of total past and forecast property premiums have been included within table 2.15.1 and 2.15.2 as this equates to the percentage of written down value of the regulatory electricity network assets relative to total assets as at 2012/13 year end.

Table 2.15.2 and 2.15.3 do not equal the totals included in Table 2.15.1 as they do not include the Risk Class "Other Insurance" as these classes do not fall into the definition of either Property or Liability.

Additional assumptions:

- Claims generally consistent with past history;
- Deductibles remaining static;
- No significant change in risk profile;
- No limit changes;
- No global events which may impact the insurance market generally; and
- No changes to stamp duty or other government imposts.

Use of estimated information

Forecast estimates were required due to the cyclical and unpredictable nature of the insurance market.

Reliability of information

Historical data is considered to be reliable. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.15.3 Insurance premium - Total liability

Compliance with requirements of the notice

As required by paragraph 11.2(b) of Schedule 1 of the RIN, the information provided in Table 2.15.3 provides more detailed information regarding total liability premiums only.

Source of information

Essential Energy sourced information from internal records and insurance brokers, Aon Risk Services (risk specialists) whose reports provided premium forecasts and past premiums.

Methodology and Assumptions

In accordance with paragraph 11.3 of Schedule 1 of the RIN, Essential Energy has forecast 2014-2019 premiums with input from our insurance brokers, Aon Risk Services, who have provided their premium estimates factoring in the cyclical insurance market using our 2013-14 budget premiums as a base.

Bushfire risk continues to be a major issue for global insurers. Black Saturday and more recent Australian fires, particularly the October 2013 Blue Mountain bushfires, remain fresh in insurers' minds and could lead to significantly increased premiums.

Additional assumptions:

- No major bushfire losses in Australia;
- Claims generally consistent with past history;
- Deductibles remaining static;
- No significant change in risk profile;
- No limit changes;
- No global events which may impact the insurance market generally; and
- No changes to stamp duty or other government imposts.

Liability insurance is purchased on a Group basis. Refer to paragraph 11.5 of Schedule 1 of the RIN which details the premium allocation methodology between the participants. In relation to proposed insurance costs an average of Essential Energy's proportion of total premium for the past five years has been applied to the totals which are based on the industry broker's (Aon) projections.

Table 2.15.2 and 2.15.3 do not equal the totals included in Table 2.15.1 as they do not include the Risk Class "Other Insurance" as these clauses do not fall into the definition of either Property or Liability.

Use of estimated information

Forecast estimates were required due to the cyclical and unpredictable nature of the insurance market.

Reliability of information

Historical data is considered to be reliable. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.15.4 Proposed self-insurance allowances by risk category

Compliance with requirements of the notice

The RIN instructions provided by the AER state “The DNSP is required to provide a list of proposed self-insurance allowances by risk category including a description of the risk and the proposed self-insurance allowance.” As Essential Energy does not propose self-insurance allowances, this table has not been completed.

Worksheet 2.16 – Opex Summary*

2.16.1 Standard control services opex by driver*

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- Efficient historic opex - The base year is 2013/14. Standard control opex figures for the base year were obtained from the regulatory accounts. ROMO was then used to forecast out these figures.
- Real price changes - Price escalators in ROMO have been switched off and the parameters inside ROMO have been copied to a base range as hard coded numbers. Escalators are then turned on in ROMO and a comparison is made on the base parameters to give yearly increments in opex created by the escalation variables. This differential is then copied into the relevant years in this table.
- Output growth is estimated to be nil each year as is
- Productivity growth is the balancing item
- Step changes – Figures only include Fault and Emergency changes due to forced capital expenditure reduction.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.16.2 Standard control services opex by category*

Compliance with requirements of the notice

Refer to section 1.8 for basis of preparation on finance data prepared for multiple tables in the RIN. The specific methodology and assumptions made for this table are outlined below.

Methodology and Assumptions

- The source of primary data for this table was the Regulatory Output Model (ROMO) for forecast years.
- Figures are based on 2013/14 dollars.
- Directs costs have been broken down into labour, materials, contractor and other costs.
- Maintenance is the balancing standard control opex figure in this table to reconcile to total standard control costs in ROMO exclusive of non network data.
- Non network has been split to only include non network standard control services opex.
- Corporate overheads are equal to corporate overheads less non network standard control services opex for each relevant financial year.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.16.3 & 2.16.4 Dual function assets opex by driver & category*

Compliance with requirements of the notice

Not applicable as Essential Energy does not own or manage dual function assets. Therefore these tables have been populated with nil values.

Worksheet 2.17 – Step Changes

2.17.1 Forecast opex step changes for standard control services

Essential Energy would like to highlight that the term 'step change' is not a defined term in the National Electricity Rules. The AER have defined step changes in its Forecast Expenditure Assessment guidelines as follows:

> *"Step changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria….*
>
> *Step changes should not double count costs included in other elements of the opex forecast. Step changes should not double count the costs of increased volume or scale compensated through the output measure in the rate of change. Step changes should not double count the cost of increased regulatory burden over time, which forecast productivity growth may already account for. We will only approve step changes in costs if they demonstrably do not reflect the historic 'average' change in costs associated with regulatory obligations. We will consider what might constitute a compensable step change at resets, but our starting position is that only exceptional events are likely to require explicit compensation as step changes. Similarly, forecast productivity growth may also account for the cost increases associated with good industry practice."*

We understand that the AER intends to use step changes to assist in developing an 'alternative' opex forecast based on an approach termed 'base-step-trend'. This allows for the determination of an annual opex forecast using base year costs and adjusting for output growth, real cost escalation and step changes.

Essential Energy believes the use of this concept has the effect of potentially excluding costs that may actually satisfy the criteria and factors in the Rules. As such we have significant reservations in the AER using the material we have provided as part of this response in its assessment process, particularly given that the term step change is not fully consistent with the approach we have used to develop our opex forecasts. For instance, while using an efficient base year concept, we have incorporated 'change factors' which identify changes in costs from the efficient base year costs that relate to future circumstances. This approach enables us to develop a precise forecast of opex that meets the Rules criteria and factors, but which cannot be precisely termed an output or step change as defined by the AER. Accordingly, in responding to this question we have applied judgement in deciding which components of our change factors best meet the AER's term of step change.

The tables in this section seek step change information for both opex and capex, however, it is clear from the AER's statements above that the concept of a step change is only relevant to the assessment of opex. Instead, the AER states that forecast capex will be generally assessed:

> *"…through assessing: the need for the expenditure; and the efficiency of the proposed projects and related expenditure to meet any justified expenditure need. This is likely to include consideration of the timing, scope, scale and level of expenditure associated with proposed projects."*

This approach recognises that capex is generally non-routine in nature, and therefore cannot be determined through a base-step-trend approach. This view is consistent with the manner in which Essential Energy has developed forecast capex, as programs are based on addressing particular needs and not on 'step changes' from a base level expenditure. As such, Essential Energy considers 'step changes' irrelevant for capex, and have not addressed this in the response below.

Compliance with requirements of the notice

- The table has been completed for all Step changes in forecast operating expenditure (including those due to changes in regulatory obligations or requirements and those due to changes in Essential Energy's own policies and strategies).
- In Table 2.17.1 Essential Energy has provided:
    - The quantum of step changes
        i. forecast to incur in each year of the forthcoming regulatory control period for opex only;
        ii. incurred, or expected to incur, in the current regulatory control period relative to expenditure previously approved by the AER; and
    - b) A description of the Step change:
- Explanations of:
    i. when the change occurred, or is expected to occur;
    ii. what the driver of the Step change is;
    iii. how the driver has changed or will change; and
    iv. Whether the Step change is recurrent in nature;

  are addressed below.
- Per 4.3 of the AER RIN requirements, Essential Energy has also provided justification for when, and how, the Step change affected, or is expected to affect the relevant opex category and total opex
- Per 4.4 of the AER RIN requirements, the process undertaken by Essential Energy to identify and quantify the Step change is also provided.
- Provided cost benefit analysis that demonstrates how Essential Energy proposes to address the Step change in a prudent and efficient manner, including:
    a) The timing of the Step change; and
    b) If Essential Energy considered a 'do nothing' option, evidence of how Essential Energy assessed the risks of this option compared with other options;
- Per 4.5 and 4.6 of the AER RIN requirements, any Step changes due to changes in regulatory or legislative obligations or requirements are highlighted.

Source of information

- The sources of information for the step changes were:
    a) The Parsons Brinckerhoff report titled "Essential Energy AER Determination Project - Review of Actual Spend vs Regulatory Allowance" (PB Report);
    b) The Global Opex model May 2014 v0.1.xlsx (Global opex model);
    c) The Global Capex model May 2014 v0.1.xlsx (Global capex model);
    d) The ROMO model; and
    e) The file titled "AER SC_13May14_Item 4.0_End to end SRP overview.xlsx"

Methodology and Assumptions

For the current regulatory period

1. The allowances reported for the current regulatory period in the Parsons Brinckerhoff report are assumed to be correct.
2. The 2010 to 2013 actuals were linked to the Global Opex model. These were agreed to the actuals reported in the PB report.
3. The difference between the actuals and the regulatory allowances were calculated and shown in the relevant cells. **Positive numbers are overspends, negative numbers are underspends.**
4. The explanations for differences were taken from the PB report. These are summarised below:

Explanations for current regulatory period differences in spend

- The increased political pressure on the state government to control electricity prices lead to the creation of Networks NSW part way through the regulatory period. Networks NSW is an overarching distribution network entity and has led to increased governance and cost control measures. This included placing a freeze on recruitment and curtailment of overtime for direct staff. This has put pressure on the availability of existing resources to progress the Inspection and Maintenance programs at the desired rates. For example, the Pole Inspection program is now estimated to be some 40,000 poles behind plan, resulting in an increased risk of pole failure and loss of service to customers.
- The Vegetation Management program has made use of new technologies and assessment methodologies. Aerial patrols and, more recently, LiDAR surveys has allowed for risk assessments to ensure the best use of available funding.
- The breaking of the nationwide drought in the middle of the regulatory period resulted in significant vegetation growth that required large amounts of work to be performed in the second half of the regulatory period.
- The uptake of residential solar photovoltaic installations was not anticipated at the time of the previous submission. This has severely impacted on metering installations and associated resources. Essential Energy's submission planned to replace approximately 240,000 outdated meters. Instead, Metering installations were completed for approximately 70,000 solar PV customers and a scaled-down programme to replace 67,000 outdated, non-compliant meters was started and will continue into the next regulatory period.
- A side-effect of the global financial crisis was that several large residential subdivisions, particularly in the north of the state near the Queensland border, were put on hold by their developers. The design effort for these growth projects included addressing known network shortcomings. With the deferment of these developments, the response to address existing network shortcomings may lead to technically inferior and less efficient solutions being undertaken.
- Emergency response spend has been consistently above the regulatory allowance. Essential Energy realises that the regulatory allowances for Emergency Response were understated and that the level of spend currently being incurred is the more realistic cost base going forward.

Use of estimated information

All forecast data (years 2014 to 2019) is estimated.

Reliability of information

Historical actual data is considered to be reliable. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.17.2 Forecast capex step changes for standard control services

Compliance with requirements of the notice

- The table has been completed for all Step changes in forecast capital expenditure (including those due to changes in regulatory obligations or requirements and those due to changes in Essential Energy's own policies and strategies).
- In Table 2.17.2 Essential Energy has provided:
    - The quantum of step changes
        i. forecast to incur in each year of the forthcoming regulatory control period;
        ii. incurred, or expected to incur, in the current regulatory control period relative to expenditure previously approved by the AER; and

- However, as described at the top of this section no explanation or justification for capex step changes is provided, as these are discussed separately within the submission and the AER will assess capex expenditure on a needs and efficiency basis.

Source of information

- The sources of information for the step changes were:
    a) The Parsons Brinckerhoff report titled “Essential Energy AER Determination Project - Review of Actual Spend vs Regulatory Allowance” (PB Report);
    b) The Global Capex model May 2014 v0.1.xlsx (Global capex model); and
    c) The ROMO model.

Methodology and Assumptions

For the current regulatory period

1. The allowances reported for the current regulatory period in the Parsons Brinckerhoff report are assumed to be correct.
2. The 2010 to 2013 actuals were linked to the Global Capex model. These were agreed to the actuals reported in the PB report.

Use of estimated information

All forecast data (years 2014 to 2019) is estimated.

Reliability of information

Actuals data is considered to be reliable. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

2.17.3 Forecast opex step changes for dual function assets

Compliance with requirements of the notice

Essential Energy has no dual function assets and therefore zeroes have been inserted into the table.

2.17.4 Forecast capex step changes for dual function assets

Compliance with requirements of the notice

Essential Energy has no dual function assets and therefore zeroes have been inserted into the table.

Worksheet 3.1 – Revenue Data for Economic Benchmarking*

3.1.1 – 3.1.2 Revenue grouping by chargeable quantity & by Customer class or type*

Compliance with requirements of the notice

This section contains shows the forecast revenue as per the requested groupings.

Source of information

Data has been sourced from the Essential Energy's Post Tax Revenue model (PTRM).

Methodology and Assumptions

The forecast revenues within the PTRM are in Nominal dollars, whereas the Reset RIN has requested the information in Real dollars. In order to comply with the request the total revenue per grouping has been divided by the Inflation Index used in the PTRM.

The revenues are grouped as per the requested chargeable quantity by the respective year. The following tables show which components were used for which group in table 3.1.1.

RESET RIN	PTRM Model
Revenue from Fixed Customer Charges	Standing Charge for all tariffs
Revenue from Energy Delivery charges where time of use is not a determinant	Non TOU Energy
Revenue from On–Peak Energy Delivery charges	Peak Energy kWh excl tariff BLNP3AO
Revenue from Shoulder period Energy Delivery Charges	Shoulder Energy kWh excl tariff BLNP3AO
Revenue from Off–Peak Energy Delivery charges	Off Peak Energy kWh excl tariff BLNP3AO
Revenue from unmetered supplies	Peak, Shoulder and Off Peak for tariff BLNP3AO
Revenue from Contracted Maximum Demand charges	Capacity kVA
Revenue from Measured Maximum Demand charges	Demand non ToU kVA, Peak Demand kVA, Shoulder Demand kVA, Off Peak Demand kVA
Revenue from metering charges	
Revenue from connection charges	Included in other sources
Revenue from public lighting charges	
Revenue from other sources	Misc & Monopoly and connection charges

The following tables show which components were used for which group in table 3.1.2.

RESET RIN	PTRM Model
Revenue from residential customers	BLNN2AU BLNC1AU BLNC2AU BLNT3AU
Revenue from non-residential customers not on demand tariffs	BLNN1AU BLNT1AO BLNT1SU BLNT2AU
Revenue from Non-residential low voltage demand tariff customers	BLND1CO BLND1SR BLND1SU BLND3AO BLNS1AO TLD
Revenue from Non-residential high voltage demand tariff customers	BHND1CO BHND1SO BHND3AO BHNS1AO BSSD3AO Site Specific
Revenue from unmetered supplies	BLNP3AO
Revenue from Other Customers	Other Income

Revenue from metering charges has been split out from year 2 onwards for alternative control services as in Year 1 this was captured within the standard control services revenue through the recovery of tariffs. This is the same basis for revenue from connection charges and public lighting charges. Ancillary network services are included in alternative control services within the revenue from connection charges line.

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

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.

Revenues reported in table 3.1.3 reflect the effect on revenues of incentive schemes in the forecast year that the penalty or reward is applied.

Source of information

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

Methodology and Assumptions

This table requires data about the payments to be paid or received by Essential Energy under the EBSS, STPIS, and other schemes. EBSS penalties have been linked to Essential Energy's Post Tax Revenue PTRM model and STPIS schemes have been predicted to be nil in future years. The DMIS incentive scheme has historically provided Essential Energy with an allowance of $600,000 annually. As such, Essential Energy assumes that this amount will stay consistent in the forecast years.

Use of estimated information

All forecast data is considered to be estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 3.2 - Operating Expenditure*

3.2.1 Opex categories

Compliance with requirements of the notice

This section contains forecast data on various opex categories allocated to both Standard Control Services and Alternative Control Services.

Source of information

Data utilised in this table has been sourced from ROMO.

Methodology and Assumptions

The opex categories shown in this table reflect those reported upon in both Essential Energy's annual RINs and the Economic Benchmarking RIN.

The forecast data for all opex categories was sourced from ROMO and linked to the appropriate cells in that model.

Use of estimated information

As the data contained in this table is forecast data, it is estimated data.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.2.2 Opex consistency

Compliance with requirements of the notice

This section contains forecast data on various opex categories allocated to both Standard Control Services and Alternative Control Services.

Source of information

Data utilised in this table has been sourced from ROMO.

Methodology and Assumptions

The opex categories shown in this table reflect those reported upon in both Essential Energy's annual RINs and the Economic Benchmarking RIN.

The forecast data for all opex categories was sourced from ROMO and linked to the appropriate cells in that model.

Use of estimated information

As the data contained in this table is forecast data, it is estimated data.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.2.3 Opex for high voltage customers*

Compliance with requirements of the notice

This section contains data on the opex that would be incurred by Essential Energy, if it owned the transformer assets owned by its high voltage customers.

Source of information

Data used in the calculation of figures reported in this table has been sourced from customer number forecasts compiled for the 2014 AER Determination, customer splits and opex estimates used to complete Table 3.4 (Opex for High Voltage Customers) in the Economic Benchmarking RIN ("the EB RIN").

Methodology and Assumptions

NA

Use of estimated information

There is an extremely high level of estimation used to complete this table.

Reliability of information

The data used for the compilation of this expenditure is highly unreliable and should not be used for benchmarking or decision making purposes. Essential Energy cannot report with any level of accuracy, on the equipment owned by its high level customers, or the running and maintenance costs of equipment which it does not own.

Worksheet 3.3 - Assets (RAB)*

Includes tables 3.3.1 – 3.3.4*

Compliance with requirements of the notice

In this section Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Essential Energy has:

- Reported its RAB assets in line with the asset input categories for economic benchmarking.
- Reported Meters (Types 5&6) as Alternative Control. Reported 0s in all the other Alternative Control Services RAB tables as the AER has not developed a RAB for these services.
- Included Substation land in the Substation categories.
- Reported capital contributions as DRAB13
- No dual function assets
- Reconciled the data between tables 4.1 and 4.2
- 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 4.3
- Calculated asset lives by weighting the lives of individual assets within that category.

Essential Energy RAB calculation method

Source of information

NA

Methodology and Assumptions

The workbook from which to follow this method is called “3.3 Assets (RAB) workings.xlsx” and the sheet is called “3.3 Assets (RAB) – Standard Nom$”.

Scope of services

Alternative Control numbers

NB. Essential Energy’s only Alternative Control RAB relates to Meters (Type 5&6) from 2015 onwards. There are 0s for all other Alternative Control cells.

Approach for deriving Standard Control and Network Services numbers

Given the move of Type 5&6 meters from Standard Control to Alternative Control from 2015, the Standard Control and Network Services numbers are identical in the Reset RIN. Fee based and quoted services costs are already excluded from Essential Energy’s RAB values so no adjustment was required for these costs in establishing the Network Services numbers.

Table 3.3.1 Regulatory asset base values

This table is a summation of the asset data contained in Tables 3.3.2 Asset value roll forward. Formulas have been entered accordingly.

There are checks to the PTRM model figures for all services down in rows 139 to 150. No discrepancies noted.

Table 3.3.2 Asset value roll forward

Some of the RAB financial information was able to be directly allocated to a group of RAB assets – these classes are summarised below. For these assets, the amounts from the RFM and the PTRM were used to complete the data tables.

Table 4 RAB categories that have been directly apportioned

OLD RAB category	New RAB category	Assumptions
Customer metering and Load Control (excluding meters type 5&6)	Meters	Assumed load control is part of Meters category
Communications	Other assets with short lives	
Land	Other assets with long lives	
Easements	Easements	
Emergency spares	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years.
Work in progress	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years. Have not apportioned WIP as is a simpler method and avoids reconciling amounts.
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.
Motor vehicles	Other assets with short lives	Assumed to be a short life asset as standard life is <10 years.
Buildings	Other assets with long lives	
Land	Other assets with long lives	Land is assumed to not depreciate
Other non-system assets	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years.
RAB adjustments	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years. Have not apportioned adjustments as is a simpler method and avoids reconciling amounts.
Deferred depreciation	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years. Have not apportioned deferred depreciation as is a simpler method and avoids reconciling amounts.
Equity raising costs	Other assets with long lives	Assumed to be a long life asset as standard life is >10 years. Have not apportioned equity raising costs as is a simpler method and avoids reconciling

OLD RAB category	New RAB category	Assumptions
		amounts.

However, five existing RAB categories required disaggregation into six new RAB categories.

Table 5 RAB categories that required disaggregation

Old RAB categories	New AER categories
Low voltage lines and cables Distribution lines and cables Sub transmission lines and cables	Overhead network assets <33kV Underground network assets <33kV Overhead network assets 33kV and above Underground network assets 33kV and above
Substations Transformers Land related to Substations	Distribution substations including transformers Zone substations including transformers

Disaggregating the RAB values for these items

NA

CAP CONS

The RAB additions noted in the category tables are exclusive of capital contributions. However, Essential Energy has received capital contributions and, as requested, amounts have been reported accordingly. The values have been taken directly from the PTRMs.

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 Tables 3.3.2. Formulas entered accordingly.

Table 3.3.4.1 Asset Lives – estimated service life of new assets

The standard life for Standard control services and Network Services assets remains unchanged. The values are consistent with the standard lives calculated in the Economic Benchmarking RAB sheet.

For Alternative control services, the standard lives match the RAB seven year write-off profile.

Table 3.3.4.2 Asset Lives – estimated residual service life

For Alternative control services, the standard lives match the RAB seven year write-off profile.

The calculations for Standard control services and Network Services assets are contained on the sheet “Asset lives” in the “3.3 Assets (RAB) workings.xlsx” workbook and the method to obtain these lives is described below.

For the disaggregated asset categories and Meters:

The opening RAB for 2014 was taken from the closing 2013 values. Additions were then added to give an “implied” closing asset base for 2014.

Note:

- It is assumed that the estimated residual service life of all assets in the Network Services columns is the same as for the Standard Control Services columns.
- Whilst substation land is included in the RAB values for Substations, it has been assumed to have an indefinite life. As such, its “age” has not been included in the residual life calculations, though its dollar value has been included in deriving the RAB proportions.
- This approach, whilst indicated by the AER as an appropriate means to weight asset lives, does imply that average asset lives for the disaggregated assets and meters decreases by about one year per annum. Accordingly, the residual asset lives increase by about one year per annum. This is against Essential Energy expectations. Given the age of the network, coupled with the decrease in expenditure over the 2015-19 period, Essential Energy would expect that residual lives would in fact decrease by between half to 1 year per annum. This misnomer is the result of using the RAB values to weight the asset lives, rather than, say, the depreciated replacement costs as was used in the Economic Benchmarking RIN. Whilst Essential Energy believes the results from the above calculations are incorrect, there is no way of accurately predicting the depreciated replacement costs, so this remains the only method that is both supported by existing data and can be undertaken in the required time.

For Other long life assets and Other short life assets:

The calculations have been undertaken in the same manner as described above, but with the additional steps of:

- Calculating residual lives for each type of asset within the class
- Then determining the overall weighted average residual life by weighting against the implied proportionate share of the closing RAB value.

The data on the *3.3 Assets (RAB)* sheet has been worked to align with the historical and forecast RFMs. As a result, the asset lives section may not agree to the asset lives referred to in other parts of the Reset RIN, for example, sheet *5.2 Asset Age Profile*.

Use of estimated information

All of the information in the Reset RIN RAB is estimated.

The assumptions made for each row are included in the section above.

Reliability of information

Essential Energy considers the data on the *3.3. Assets (RAB)* sheet to be unreliable. This is due to the number of estimates in the data and the various assumptions that had to be made to extract this data to the level required. Caution should be used when using this information for decision making or benchmarking purposes.

In addition, based on an SKM valuation undertaken as at 30 June 2007, Essential Energy’s RAB values are significantly lower than what its assets are actually worth.

This RAB undervaluation creates a peculiarity when the RAB values must be relied upon to weight the residual asset lives for assets requiring disaggregation and Meters – it indicates that residual lives for those asset categories are increasing when Essential Energy would actually expect them to be decreasing given the forecast reduction in spending and the actual age and value of the network.

As mentioned above, the data on the 3.3 Assets (RAB) sheet has been worked to align with the historical and forecast RFMs so the asset lives may differ from those referred to in other parts of the Reset RIN, for example, sheet 5.2 Asset Age Profile.

As a result of all these factors, Essential Energy considers the RAB values to be a very unreliable measure if used in any benchmarking comparisons.

Worksheet 3.4 - Operational Data for Economic Benchmarking*

3.4.1 Energy Delivery*

Compliance with requirements of the notice

This section shows the forecast energy as per the requested groupings.

Source of information

Methodology and Assumptions

Table 3.4.1.1 Energy grouping - delivery by chargeable quantity

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

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

Table 3.4.1.4 Energy grouping - customer type or class

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.4.2 Customer numbers*

Compliance with requirements of the notice

This section shows the forecast customer numbers as per the requested groupings.

Source of information

Methodology and Assumptions

Table 3.4.2.1 Distribution customer numbers by customer type or class

Table 3.4.2.2 Distribution customer numbers by location on the network

This table links to the estimates in table 6.2.4.

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.4.3 System demand*

Includes data tables 3.4.3.1 – 3.4.3.7

Compliance with requirements of the notice

The AER nominate time periods that are based on financial years. However, the Essential Energy definition differs from the AER definition. An example of how Essential Energy defines a time period is that 2008/09 includes the summer period of 2008/09 and the winter period of 2009 (say from October 2008 to September 2009). For forecasting purposes the AER definition does not work and should be disregarded. A practical example of why it does not work is that a system peak occurred on 19 July 2011 but the next system peak occurred on 18 January 2013. Clearly the dates meet the financial year requirement, i.e., 2011/12 and 2012/13, however from a seasonal perspective, they miss the periods of summer 2011/12 and winter 2012. Clearly it would be negligent of an organisation or individual not to consider all seasonal data in forecasting.

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

Source of information

The vast majority of historical zone substation demand data is sourced from demand meters (via IMDR) and from SCADA (via TrendSCADA). Of the small remainder of zone substations, the vast majority of information is sourced directly from data stored on individual reclosers with only a handful of zone substations having maximum demand indicators or no data recording devices whatsoever.

Those individual zone substation forecasts are shown in table 5.4.1.

Methodology and Assumptions

Essential Energy has not historically derived weather adjusted demands. Therefore all values provided in the table are not weather adjusted.

The historical terminal station demand data is sourced from demand meters at individual terminal stations. From that historical data, forecast demands for the individual terminal stations are derived using Excel algorithms and local planner knowledge. That same demand data is used in another algorithm that inputs a number of external factors, such as population growth, to derive demand forecasts.

The date and time of the Essential Energy peak system demand are the time periods used to determine historical coincident demands at the individual terminal stations.

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

DOPSD0401 Summated Chargeable Contracted Maximum Demand – Essential Energy does not have contracted Demand

DOPSD0402 Summated Chargeable Measured Maximum Demand – NIEIR does not provide for this Tariff_ only Snapper and Ginko Mines - held at 2013 level

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

Information is based on NIEIRs forecast for the relevant tariff.

Use of estimated information

Refer to the methodology and assumptions section above for information on the use of estimated data.

Reliability of information

Data for DOPSD0102, DOPSD0105, DOPSD0108, DOPSD0111, DOPSD0202, DOPSD0205, DOPSD0208 and DOPSD0211 in table 3.4.3 is considered to be unreliable.

All other forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 3.5 - Physical Asset Data for Economic Benchmarking*

3.5.1.1 Overhead network length of circuit at each voltage*

Compliance with requirements of the notice

The information provided reports a forecast of overhead circuit kilometres for both high voltage and low voltage feeders to be added in the 14/15 to 18/19 period.

Source of information

The data for the forecast was taken from the approved Program of Works for 14/15 in the planning database which was then added to the 13/14 data supplied for the Economic Benchmarking RIN.

Methodology and Assumptions

The Reset RIN definition of 'Route Line Length' & 'Circuit Line Length' specifically says not to include service lines, therefore overhead and underground service lines has been excluded.

The data was sourced by running an 'AER Category Summary Report' in the planning database for the 14/15 FY. This data forms the approved 14/15 Program of Works.

The data was the filtered for:

- HV OH – New
- HV OH Interconnectors – New
- LV OH – New

Data was further filtered for the appropriate voltage levels required.

Use of estimated information

Both these programs are targeting removal of LV overhead conductors, whilst the current planning criteria effectively mandate no new overhead low voltage construction.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.5.1.2 Underground network length of circuit at each voltage*

Compliance with requirements of the notice

The information provided reports a forecast of underground circuit kilometres for both high voltage and low voltage feeders to be added in the 14/15 to 18/19 period.

Source of information

Methodology and Assumptions

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.5.1.3 – 3.5.1.4 Estimated overhead and 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 fore mentioned 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;

Methodology and Assumptions

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

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.5.2 Transformer Capacities Variables*

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.

Table 6.2 Transformer Capacities Variables

Table 6.2.1 Distribution Transformer total installed capacity

Essential Energy must report total installed Distribution Transformer capacity in this table. The total installed Distribution Transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (eg 132 kV or 66 kV to the 22 kV or 11 kV distribution level). The capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).

This measure includes Cold Spare Capacity of Distribution Transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.

Distribution Transformer capacity owned by utility

Report transformer capacity owned by Essential Energy; give nameplate continuous rating including forced cooling.

Distribution Transformer capacity owned by High Voltage Customers

Report the transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage.

If the transformer capacity owned by customers connected at high voltage is not available, report summation of individual Maximum Demands of high voltage customers whenever they occur (ie the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers.

When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Essential Energy can provide Actual Information for Distribution Transformer capacity owned by High Voltage Customers it must do so; otherwise Essential Energy must provide Estimated Information.

Cold Spare Capacity included in DPA0501

Report the total capacity of spare transformers owned by Essential Energy but not currently in use.

Cold Spare Capacity	The capacity of spare transformers owned by Essential Energy but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.
Distribution Transformer	A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.
Transformers	These are assets used to transform between voltage levels within the network This includes all its components such as the cooling systems and tap changing equipment (where installed) It excludes any pole mounted assets that are included in any other asset category. For the avoidance of doubt, this does not include instrument transformers as defined in the National Electricity Rules.
Asset	A resource controlled by an entity as a result of past events and from which future economic benefits are expected to flow to the entity

Source of information

This data has been sourced from:

- Current Distribution Transformer MVA extracted from the WASP system as reported in table 6.2.1 in the Economic Benchmarking RIN.

Methodology and Assumptions

1. Determine the current Distribution Transformer Capacity values.
    a. This was determined as part of the Economic Benchmarking RIN. Refer to the Basis of Preparation for table 6.2.1 for the Economic Benchmarking RIN. The 2013 values were used as base values.

Use of estimated information

The base MVA figures use estimated information as detailed in the Basis of Preparation for table 6.2.1 for the Economic Benchmarking RIN.

The added MVA figures are based on estimated future planned distribution transformer replacements/installations and will not take into account asset replacement due to unexpected failures or changes in funding allocations.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

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.

Table 6.2.2 Zone substation transformer capacity

Report transformer capacity used for intermediate level transformation capacity in either one or two steps. For example, high voltages such as 132 kV, 66 kV or 33kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6kV.

These measures must be the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included) and include both energised transformers and Cold Spare Capacity. Assigned rating must be, if available the rating determined from results of temperature rise calculations from testing. Otherwise report the nameplate rating. For those zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders should be reported instead of transformer capacity.

Total installed capacity for first step transformation where there are two steps to reach distribution voltage

"Total installed capacity for first step transformation where there are two steps to reach distribution voltage" (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or 11 kV where there will be a second step transformation before reaching the distribution voltage. This variable is only relevant where Essential Energy has more than one step of transformation, if this is not the case Essential Energy must enter '0' for this variable.

Total installed capacity for second step transformation where there are two steps to reach distribution voltage

For "Total installed capacity for second step transformation where there are two steps to reach distribution voltage" (DPA0602) report total installed capacity where a second step transformation is applied before reaching the distribution voltage. For example 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within Essential Energy's system. This variable is only relevant where Essential Energy has more than one step of transformation, if this is not the case Essential Energy must enter '0' for this variable.

Total zone substation transformer capacity where there is only a single transformation to reach distribution voltage

For "Total zone substation transformer capacity where there is only a single transformation to reach distribution voltage" (DPA0603) report total installed capacity where only a single step of transformation is applied before reaching the distribution voltage. This variable is only relevant where there is only a single step of transformation to reach distribution voltage. If there is more than one step of transformation to reach distribution voltage, the relevant capacities must be reported in DPA0601 and DPA0602.

Total zone substation transformer capacity

For 'Total zone substation transformer capacity' (DPA0604) report the overall total zone substation capacity regardless of whether one or two steps are used to reach the distribution voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.

Cold Spare Capacity of zone substation transformers included in total zone substation transformer capacity

For 'Cold Spare Capacity of zone substation transformers included in DPA0604' (DPA0605), report total Cold Spare Capacity included in total zone substation transformer capacity.

Cold Spare Capacity	The capacity of spare transformers owned by Essential Energy but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.

Source of information

This data has been obtained from:

- Current Zone Substation Transformer MVA extracted from the WASP system as reported in table 6.2.2 in the Economic Benchmarking RIN.
- A list of Zone Substations Transformers planned for refurbishment/replacement due to asset condition/age, maintained by the Zone Substation Maintenance Group
- A list of new Zone Substations planned or plans for the augmentation/upgrade of existing Zone Substations due to growth/capacity, maintained by the Sub transmission Planning Group.

Methodology and Assumptions

1. Determine the current Zone Substation Transformer Capacity values.
    a. This was determined as part of the Economic Benchmarking RIN. Refer the Basis of Preparation for table 6.2.2 for the Economic Benchmarking RIN. The 2013 values were used as base values.

2. Forecast MVA to be added Zone Substation Transformers planned for refurbishment / replacement due to asset condition / age
    a. The PIP (Portfolio Investment Plan) contains a list of Power Transformers planned for replacement or refurbishment due to asset condition or age.
    b. The additional MVA added for any Transformer upgrades was determined for each year from this list.

3. Forecast MVA to be added for new Zone Substations planned or plans for the refurbishment / upgrade of existing Zone Substations due to growth/capacity driving by the Subtransmission Planning Group:
    a. The PIP (Portfolio Investment Plan) contains a list of the major project / program of works planned for the following regulatory period was obtained.
    b. The PIP was reviewed for any projects involving Zone Substation Transformer replacements and the additional MVA added was determined for each year.

4. The additional MVA from steps 3 and 4 were then added to the base values determined in step 1 to arrive at the final Zone Substation Transformer Capacities for each year in the next regulatory period.

It is assumed that going forward the majority of augmentations will be refurbishment / asset condition replacements.

Use of estimated information

The base MVA figures use estimated information as detailed in the Basis of Preparation for table 6.2.2 for the Economic Benchmarking RIN.

The added MVA figures are based on estimated future planned zone substation transformer replacements/installations and will not take into account asset replacement due to unexpected failures or changes in funding allocations.

Reliability of information

These figures are based on estimated future planned zone substation transformer replacements/installations and will not take into account asset replacement due to unexpected failures or changes in funding allocations. 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 the Basis of Preparation for table 6.2.2 for the Economic Benchmarking RIN. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

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. Assets owned by Essential Energy and assets operated and maintained by Essential Energy but not owned by Essential Energy have been included.

6.3 Public lighting

Report the number of public lighting luminaires and public lighting poles. For both Variables report numbers that include both assets owned by Essential Energy and assets operated and maintained by Essential Energy but not owned by Essential Energy. Count only poles that are used exclusively for public lighting.

Public lighting services	*Public lighting services* are the installation, repair, replacement and maintenance of public lighting whether owned by the NSP or by another party. This also includes alteration and relocation of existing public lighting assets. Public lighting assets include luminaires, brackets, lamps and dedicated public lighting poles (not poles that deliver network services).

Source of information

This data has been sourced from:

- Current Public Lighting luminaire and pole figures extracted from the WASP system as reported in table 6.3 in the Economic Benchmarking RIN.

Methodology and Assumptions

1. Determine the current Public Lighting values.
    a. This was determined as part of the Economic Benchmarking RIN. Refer the Basis of Preparation for table 6.3 for the Economic Benchmarking RIN. The 2013 values were used as base values.

2. Determine the average growth rate for Public Lighting Luminaires and Public Lighting Poles over the past 8 years (as reported in the Economic Benchmarking RIN) as follows:

    Public Lighting Poles:

    a. The growth rate for each year from 2006 to 2014 was determined
    (([Total for Year 2] - [Total for Year 1])/[Total for Year 1])*100

    E.g. for 2010:
    (([Total for 2011] - [Total for 2010])/[Total for 2010])*100

    b. The growth rate for each of the 8 years was averaged which resulted in an average growth rate of 3.4% per annum for Public Lighting Poles.
    (Growth Rate 06/07 + Growth Rate 07/08….+ Growth Rate 13/14)/8

Public Lighting Luminaires:

a. The growth rate for each year from 2006 to 2014 was determined
(([Total for Year 2] - [Total for Year 1])/[Total for Year 1])*100

E.g. for 2010:
(([Total for 2011] - [Total for 2010])/[Total for 2010])*100

b. It was determined that the growth rate for the 2013 year is most accurate and most likely to reflect the forecast for the next 5 years. Therefore the growth rate for Luminaires was set at 1.7% per annum.

3. Apply the average growth rate determined in step 2 for Public Lighting Luminaires and Public Lighting Poles to the base figures determined in step 1 for each future year.

   a. The growth rate for each year from 2006 to 2014 was determined
   [Regulatory Year 1] = [Base Figure from Step 1] * [Growth Rate from Step 2]

   [Regulatory Year 2] = [Year 1] * [Growth Rate from Step 2]

   ….

   [Regulatory Year 5] = [Year 4] * [Growth Rate from Step 2]

Use of estimated information

The base/current Public Lighting figures use estimated information as detailed in the Basis of Preparation for table 6.3 for the Economic Benchmarking RIN.

Reliability of information

These figures are based on estimated growth in Public Lighting Poles and Luminaires based on historic growth trends. The figures used as a base for current Public Lighting Poles and Luminaires are dependent on the accuracy of the data within the WASP database and the estimations and made as per the Basis of Preparation for table 6.3 for the Economic Benchmarking RIN. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 3.6 - Quality of Service Data for Economic Benchmarking*

3.6.1 Energy not supplied*

Compliance with requirements of the notice

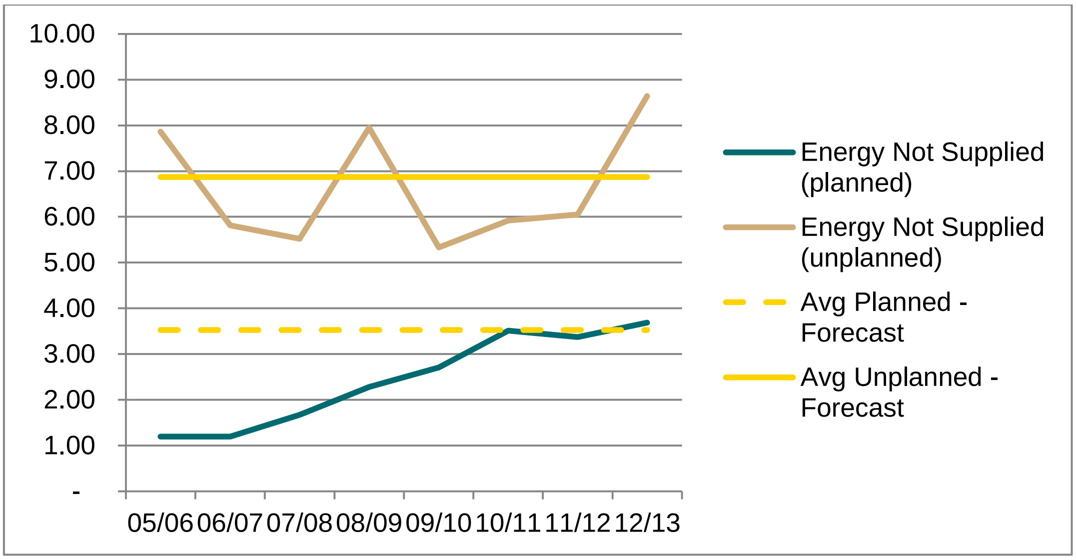
This section shows the forecast GWH for energy not supplied both planned and unplanned.

Source of information

The forecast information has been based on historical numbers.

Methodology and Assumptions

The energy supplied for both planned and unplanned outages has been based on an average of the last three years data. The historical data and forecast can be seen in the following chart.



The planned energy not supplied increases due to an improvement in the reporting and systems for recording this information, therefore only the past three years have been used in the forecast.

The unplanned energy not supplied is difficult to forecast as it is highly dependent on the frequency and severity of storms in the network area. Due to this the same principle has been used basing the forecast on the previous three years.

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.6.2 System losses*

Compliance with requirements of the notice

This section shows the forecast losses.

Source of information

NA

Methodology and Assumptions

NA

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.6.3 Capacity utilisation*

Compliance with requirements of the notice

This section follows the economic 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

Result is formula driven and data utilised in Table 3.6.3 came from Table 3.4.3.3 and Table 3.5.2.2.

Methodology and Assumptions

Essential Energy has ignored feeder capacity and used;

Table 3.4.3.3 Non–coincident Weather Adjusted System Annual Maximum Demand divided by Table 3.5.2.2 Total zone substation transformer capacity.

Use of estimated information

The calculation is based on tables that have been provided. Please refer to Table 3.4.3.3 and 3.5.2.2.

Reliability of information

The calculation is based on tables that have been provided. Please refer to Table 3.4.3.3 and 3.5.2.2. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 3.7 - Operating Environment Factors for Economic Benchmarking*

3.7.1 Density factors*

Compliance with requirements of the notice

This section has been completed as per the provided formulas in the economic RIN Instructions and Definitions document 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 3.4.1.2 Energy Received from TNSP, Table 3.4.1.3 Energy received from embedded generation and Table 3.4.2.2 Total customer numbers.

'Demand Density' sources information from Table 3.4.3.3 Annual system maximum demand, DOPS0203, and Table 3.4.2.2 Total customer numbers.

Methodology and Assumptions

The methodology used in this section was as provided in the economic RIN Instructions and Definitions document 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 which is the sum of the Energy received from the TNSP plus the Energy received into the DNSP system from embedded generation divided by the total number of customers of the network.

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

Use of estimated information

These calculations are based on tables that have been provided, please refer to Table 3.4.2.2, Table 3.7.3, Table 3.4.1.2, Table 3.4.1.3 and Table 3.4.3.3.

Reliability of information

These calculations are based on tables that have been provided, please refer to Table 3.4.2.2, Table 3.7.3, Table 3.4.1.2, Table 3.4.1.3 and Table 3.4.3.3. All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.7.2 Terrain factors*

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

- WASP system
- Essential Energy Vegetation Cost Model
- Field survey 2011/12
- Smallworld system

Methodology and Assumptions

Rural proportion

Based on data from the 2012/13 financial year rural proportion is calculated as short rural feeder length plus long rural feeder length divided by the total route feeder length.

Urban and CBD vegetation maintenance spans

The number of urban maintenance spans from FY13 plus the total number of spans expected to convert from potential to actual maintenance spans from the Essential Energy Vegetation Cost model for each of the outer year

The number of future maintenance spans relies on assumptions around cycle, number of new plantings, the amount of new plantings dealt with before they reach maturity and conversely the number of new plantings not dealt with before they reach maturity.

Rural vegetation maintenance spans

The number of rural maintenance spans from FY13 plus the total number of spans expected to convert from potential to actual maintenance spans from the Essential Energy Vegetation Cost model for each of the outer year

The number of future maintenance spans relies on assumptions around cycle, number of new plantings, the amount of new plantings dealt with before they reach maturity and conversely the number of new plantings not dealt with before they reach maturity.

Total vegetation maintenance spans

Sum of Rural and Urban vegetation spans outlined in the previous two metrics.

Total number of spans

2015 is calculated by using the total number of in service poles stored in the WASP system for the 2013 financial year, less one, multiplied by the average annual percentage increase for the previous regulatory period. Each subsequent year uses this percentage increase multiplied by the calculated number of the year previous.

Average urban and CBD vegetation maintenance span cycle

For the period of 2015-19 Essential Energy has a planned weighted average urban maintenance span cycle of 1.5 years.

Average rural vegetation maintenance span cycle

For the period of 2015-19 Essential Energy has a planned weighted average rural maintenance span cycle of 3 years.

Average number of trees per urban and CBD vegetation maintenance span

The vegetation density for all years is based on field survey data from the 2011/12 financial year. 30 vegetation maintenance areas were surveyed across the Essential Energy urban network with the sample made up of vegetation maintenance areas from each of the five vegetation maintenance Zones.

Average number of trees per rural vegetation maintenance span

The vegetation density for all years is based on field survey data from the 2011/12 financial year. 66 vegetation maintenance areas were surveyed across the Essential Energy rural network with the sample made up of vegetation maintenance areas from each of the five vegetation maintenance Zones.

Average number of defects per urban and CBD vegetation maintenance span

Total number of defects reported from all sources for vegetation stored in the WASP system for the 2013 financial year as a baseline divided by the total number of maintenance spans for urban areas for each of the financial years.

Average number of defects per rural vegetation maintenance span

Total number of defects reported from all sources for vegetation stored in the WASP system for the 2013 financial year as a baseline divided by the total number of maintenance spans for rural areas for each of the financial years.

Tropical proportion

The approximate number of vegetation maintenance spans in the hot humid summer and warm humid summer regions as defined by the below map.

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

Data source was the Essential Energy GIS, Smallworld.

Uplift for outer years is based on the percentage increase in tropical proportion from 2012 to 2013.

Standard vehicle access

The total number of poles that have a Terrain Type in WASP of "Accessible" as entered by (for the most part) asset inspectors divided by the total poles in the network to get a percentage of standard access for the pole network (87%) for the 2013 year.

The remaining 13% was then applied to the total number of kilometres of line in the Essential Energy network and assumes that all spans are inaccessible if the pole is inaccessible.

Annual increase in kilometres of line is based on the percentage increase over the current regulatory period divided by five to get the annual increase for the outer years.

Bushfire risk

Essential Energy has an annual bushfire mitigation aerial patrol program that is carried out across the entire rural network. On this basis all rural spans have been included as a bushfire risk.

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

3.7.3 Service area factors*

Compliance with requirements of the notice

Essential Energy has estimated the forecast total route line length in accordance with the template requirements. The definition of route line length includes both overhead and underground network line, but excludes underground street light and LV service line lengths.

Source of information

Essential Energy has estimated forecast route line lengths based on the average route length/circuit length ratio for years 2010 – 2013 that was used to estimate route line lengths in the Economic Benchmarking RIN.

This ratio was applied to the forecast total overhead circuit lengths identified in table 3.5.1.1 for each of the forecast years 1 through 5.

Methodology and Assumptions

Essential Energy has assumed a constant ratio of circuit length to route length during the forecast years.

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 4.1 - Public Lighting

4.1.1 Descriptor Metrics over Current Year

Compliance with requirements of the notice

Essential Energy has populated Tables 4.1, 4.1.2 and 4.1.3, as required.

Source of information

Data was consolidated from individual Local Government Area (LGA) end of financial year asset inventory reports. These reports include all devices except metered and/or quarantined devices.

These devices were excluded for the following reasons:

- Quarantined lights do not contain enough information to determine the luminaire size
- Metered lights are the responsibility of the owner for maintenance and replacement, and the energy consumption is not calculated using the Type7 Unmetered Billing System. As such not all metered lights have been captured in the Wasp database.

These reports are generated through Cognos Report Studio using a materialised view created for the Streetlight Business Unit. On 1/7/2013, 25 reports failed to generate. This was not realised until the commencement of this process. As it is not possible to retrieve counts of data for past dates, asset details were extracted from Wasp on 10/2/2014 using Report Studio for the failed LGA reports.

Methodology and Assumptions

Count of individual device types from above data source.

Use of estimated information

As all information has been sourced from WASP and is considered as actual data, there have been no estimations made.

Reliability of information

The data is considered to be reliably consistent with the source system, however is dependent upon the quality of the data in the source system.

4.1.2 Descriptor Metrics Annually

Compliance with requirements of the notice

Essential Energy has populated Tables 4.1, 4.1.2 and 4.1.3, as required.

Source of information

The streetlight volume data was sourced from Wasp using Cognos Report Studio.

The pole volume data along with averaged pole replacement cost was supplied by Asset Strategy Development. The pole volume data was extracted from WASP and data provided by Asset Strategy Development related only to dedicated streetlight supports.

Material costs were sourced from procurement Contract 10/2008 Period 4 1/9/2012 to 30/6/2013 for routine work. These costs have not had any CPI increases applied to them. Non routine task material costs were taken from SLUOS Construction Charge Calculation Model V1.12 20071204 and have had annual CPI increases applied for each year until 2013/2014. The cost applied in

2013/2014 was used as a standard cost for all projections. Where materials costs were not available, costs of similar size materials was used.

Bracket data is not collected in the current asset management system, so there is no reference to volumes and/or costs within this data.

Pole replacement cost of $5,390.33 was advised by Asset Strategy Development for 2013/2014 year. This figure was used as a constant figure from year 2008-2009 to 2018-2019 as no other costs were available.

Pole inspection cost was advised as $47. This figure was used as a constant figure from year 2008-2009 to 2018-2019 as no other costs were available.

Supporting evidence stored on network drive Networks/Streetlighting/Data Quality/RIN 2014/Reset RIN Template 24 Feb 2904 Supporting Evidence incl Summary.xlsx

Methodology and Assumptions

The following assumptions have been made to classify the devices and task types for the purpose of this reporting:

Description	Definition
Major Road Lighting	Luminaires with wattage 150 or higher
Minor Road Lighting	Luminaires with wattage less than 150
Routine Maintenance/Replacement	Work performed by contractors
Non-Routine Maintenance/Replacement	Work performed by Essential Energy
Public Lighting	Installed Type 7 Unmetered lights that are billed through Unmetered Billing System

Installed Lights

Installed light volumes were extracted from Wasp Asset History using following criteria:
Change history before value was null
Change history after value was not null
Change history date changed was between 01/07/2009 and 31/01/2014
Change history description = Public Lighting Load Table Code
Asset category = Streetlight

The streetlight data was categorised between major and minor road using the wattage assumption above. Installed light forecasts for 2013-2014 were been calculated by taking the closing inventory from 2012-2013, multiplying this by the growth factor of 1.71%. This figure was then split into major and minor light installations after identifying the % split on the number of installed lights in the 2012-2013 year. These factors were calculated as 34% for major lights and 66% for minor lights.

Further streetlight forecasting was then calculated by adding the forecasted growth to the previous year's closing inventory and then applying the growth factor of 1.71%, splitting major and minor by the previously advised factors.

The dedicated support inventory was unknown as at 30/6/2013 so an inventory was taken on 8/4/14. The number of dedicated supports was derived by dividing the number of lights on each of the supports into the number of devices in the extract.

Dedicated support installations were then calculated by taking the calculated total from 8/4/14 and multiplying by a growth factor of 3.4%. This was then split between major and minor after identifying the % split on the number of installed dedicated supports in the 2012-2013 year. These factors were calculated as 37.6% for major and 62.4 for minor.

Further dedicated support forecasting was then calculated by adding the forecasted growth to the previous year's closing inventory and then applying the growth factor of 3.4%, then splitting major and minor by the previously advised factors.

There are no costs associated with any light or pole installations as these are deemed as gifted assets.

Replacement Lights

Work Task records were extracted for each individual year applying following criteria:
Asset Category = Streetlight
Task Status <> Cancelled
Task Codes = LLUR (Change Luminaire)
LBUR (Bulk Luminaire Replacement)

Non-Routine

Material costs sourced from SLUOS Construction Charge Calculation Model V1.12 2007/12/04. Standard luminaire raw cost used. Costs were increased by CPI each year.

The CPI % rates used are as follows:

2008-2009	2.33%
2009-2010	4.35%
2010-2011	1.82%
2011-2012	2.85%
2012-2013	3.39%
2013-2014	1.75%

.

Unit labour rate was calculated from P&L Total Opex less Nightvision, less Contract Opex less total calculated material $ divided by total tasks performed. This calculation was done for each year up to 2012/2013.

Routine

Material costs sourced from Contract 10/2008 Period 4 1/9/2012 to 30/6/2013. Standard luminaire raw cost was used. This rate was used as a standard rate for all years. Unit labour rate negotiated with contractor dated 20/6/2011 was used as a standard rate for all years.

Total cost reported for replaced lights include calculated material, labour and pole replacement costs as described above.

The large rise in replacement tasks for years 2011/2012 and 2012/2013 is due to the bulk luminaire replacement program that was undertaken.

Maintained Lights

Work Task records were extracted for each individual year applying following criteria:
Asset Category = Streetlight
Task Status <> Cancelled
Task Codes = LPLP (Standard Maintenance)
= LMRQ (Minor Maintenance)
= LENE (Energise Luminaire)
= LDEN (De-energise Luminaire)

= LFGS (Glare Shield
= LFWG (Wire Guard)
= LMSL (Remove Luminaire)
= LINV (Investigate)
= LBUP (Bulk Lamp Replacement)

In 2011 there was a consolidation of work task codes where all tasks required to perform a job were grouped under one task code thus reducing the number of available task codes.

Non-Routine
Material costs sourced from SLUOS Construction Charge Calculation Model V1.12 2007/12/04. Standard lamp and PE cell raw costs were used. Costs were increased by CPI % each year.
The CPI % rates used are as follows:
2008-2009 2.33%
2009-2010 4.35%
2010-2011 1.82%
2011-2012 2.85%
2012-2013 3.39%
2013-2014 1.75%
Unit labour rate was calculated from P&L Total Opex less Nightvision, less Contract Opex less total calculated material $ divided by total tasks performed. This calculation was done for each year up to 2012/2013. The value was prorated for 2013/2014 and that figure was used for forecasted periods 2015-2019.

Routine
Material costs sourced from Contract 10/2008 Period 4 1/9/2012 to 30/6/2013. Standard luminaire raw cost was used. This rate was used as a standard rate for all years. Unit labour rate negotiated with contractor dated 20/6/2011 was used as a standard rate for all years.

Total cost reported for maintained lights include calculated material, labour and pole inspection costs as described above.

Quality of Supply

Means Days
This number was derived from extracted work task data for each year where Reported By = Streetlight Web Interface to arrive at the number of customer reported faults. The days to repair were calculated using an expression written by the Cognos group in 2011 which allowed the calculation of work days excluding weekends and public holidays. This code has been embedded into the Streetlight Business Unit materialised view, accessed using Cognos Report Studio.

Calculation = total days to repair divided by total number of customer reported faults.

This method was used for years 2011 – 2014.

Mean days for 2008-2009 were taken from Annual Compliance Report NSW Distribution Network Service Provider 2008/2009 dated July 2009. as the above method was not available for these years.

Mean days for 2009-2010 were taken from PR10 Streetlight Repair Performance Report generated through Report Studio using Fast data on 15/7/2010. This data is no longer available.

Volume of GSL Breaches, Payments & Customer Complaints
This data was provided by Customer Relations team as previously reported end of year data.

Use of estimated information

All streetlight forecasted information has been estimated using a growth rate of 1.71% and pole data using a growth rate of 3.4% as identified in table 3.5.3 from the Economic Benchmarking RIN.
Work task data populating 2008-2009 has been applied using the 2009-2010 figures with the exception of the bulk (routine) maintenance and replacements as these programs had not commenced at this time. The 2009-2010 data was used as this was believed to be a better estimation than the data recorded.
Pole inspection volume data for 2013/2014 was set at 25% of the number of dedicated streetlight supports as at 31/3/2014.

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

4.1.3 Cost Metrics

Compliance with requirements of the notice

Essential Energy has populated Tables 4.1, 4.1.2 and 4.1.3, as required.

Source of information

Refer BOP for table 4.1.2

Methodology and Assumptions

Work tasks for individual light types were categorised between routine and non-routine maintenance/replacement. Material and labour costs only were then applied from data collected for table 4.1.2. These average unit $ do not include pole costs.

Weighted average unit $ were then calculated by totalling all material and labour values and dividing by total number of work tasks.

The fluctuation in average unit costs relates to the number of routine and/or non routine maintenance and replacement tasks. More routine and less non-routine calculates a lower average unit cost whereas more non-routine and less routine calculates a higher average unit cost.

Use of estimated information

All streetlight forecasted information has been estimated, and caution should be used when using for benchmarking or decision making purposes..

Reliability of information

Allocations performed on historical data are based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes. All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 4.2 - Metering

4.2.1 – 4.2.2 Metering descriptor metric & Cost metrics

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice.

Source of information

There are four main sources used to obtain information for the completion of the Metering tables:

1. EDDIS (Energy Data Distribution System). This system is used by metering services to store and process meter readings and meter registry information pertaining to chapter 7 of the NER.
2. The Customer Metering Asset Management Plan for 2012 – 2019.
3. Reports and budgetary information from PeopleSoft
4. Investment cases ESS-91 Meters for New Connections and ESS_93 Meter Replacement Program.

Methodology and Assumptions

Table 4.2.1 – Metering Descriptor Metric

Meter population Volumes for years 2012/13 were achieved through queries of the EDDIS database, with the query providing total number of meters by type.

Population data for years 2008/09 to 2011/12 were calculated based on the historical meter usages, customer growth numbers and analysis of historical meter failures. As this meter installation information is constantly subject to change it is difficult to ascertain this information through database queries.

The multiphase population for Type 4 meters went from ~500 sites in 2011/12 to zero in 2012/13 due to a reclassification in the National Electricity Market (NEM) of these sites to Type 5. The sites are shown in the Type 5 multiphase populations for the years 2012/13 onwards.

The overall population of meters increased at a greater rate in the years 2010/11 to 2012/13 due to the uptake of Solar. Additional meters needed to be purchased to support both gross and net solar metering arrangements.

Table 4.2.2 – Cost Metrics

Meter Purchase – Information from 2008/09 to 2011/12 has been based on meter purchase history. Financial reports from PeopleSoft have been used for 2012/13.

Meter Testing - Meter testing includes the regulatory compliance testing of meters undertaken by Essential Energy in accordance with the NER.

Information from 2008/09 to 2012/13 is based on financial reports from Peoplesoft and queries from the EDDIS database for the number of jobs completed. Volumes for 2008/09, 2009/10 and 2011/12 are zero as no testing was scheduled to be conducted in these years. Information from 2013/14 onwards is based on data from the Customer Metering Asset Management Plan for 2012 – 2019.

Meter Investigation and Special Meter Reading - are all zero as they have been covered by Network Operation in Section 4.3 Fee Based Services.

Scheduled Meter Readings - Information from 2008/09 to 2012/13 is based on financial reports from PeopleSoft and queries conducted by the Meter Reading team.

New Meter Installs - All data for this section is zero as new meter installs are either conducted by Accredited Service Providers or where an installation of metering with Current Transformers installed this work is carried out by Metering Services on a quote for service basis and therefore not included.

Meter Replacement - Meter replacement includes the pro-active replacement of meters that have failed to meet compliance under the NER. Trial of replacement processes was conducted in 2012 using metering technicians, with further small trial undertaken in 2013 using network operations employees.

No replacements were completed prior to 2012.

Meter Maintenance – Meter maintenance includes the routine maintenance of meters, including replacement of meters that have failed in service.

Data prior to 2013/14 is estimated based on unplanned failure rates.

Remote Meter Reading - Information from 2008/09 to 2012/13 is based on financial reports from PeopleSoft and queries run from EDDIS. From 2012/13 onwards the data is zero as the sites had changed from being a Type 4 installation to a Type 5 installation. No unregulated services have been included.

Other Metering Type 6 - This is financial information relating to the Intelligent Network trial in Bega. Data was extracted from Project ID's 585468 and 585473 from "IN_Communities_Program_JUNE12_FINAL_2012_08_18.pdf". It also includes Meter Data Agency, Laboratory and Meter Provision support functions.

Other Items - All other cells were left as zeroes as no work was conducted in these categories

For further information on the how the financial data was prepared, refer to section 1.8 of this document.

Use of estimated information

Refer to methodology and assumptions above. All forecast information is estimated.

Reliability of information

Historical data is based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes. All forecast information is considered to be estimated and caution should also be used when using his for benchmarking or decision making purposes.

Worksheets 4.3 & 4.4 - Ancillary Services – Fee Based & Quoted Services

4.3.1 – 4.4.1 Cost metrics for fee-based and quoted services

Compliance with requirements of the notice

Essential Energy has provided estimated costs and volumes for each of the Ancillary Service Fees it proposes to charge for the future regulatory period.

Source of information

The historical volumes for re-energisations, de-energisations, move in/ move out reads, special reads, meter tests and off peak conversions have been sourced from reports based on Process Tracking Jobs (PTJs). The systems used to provide the reporting include TCS (2008-09 to 2011/12), PowerOn Fusion (2012/13) and Yambay/JSS (2013/14). The historical expenditure corresponding to the volumes has been sourced from PeopleSoft Financials, Cognos and the Budgeting and Forecasting Tool (used to source 2013/14 Forecast). Estimated labour, plant and stores requirement for each PTJ type has been provided by subject matter experts (field-based).

For the remaining fee-based services Essential Energy has not had a practice of keeping detailed accounting records of the input costs associated with Miscellaneous Service Fees. The estimated costs and volumes provided in this response have been based on the revenue billed, supplemented by limited data from Essential Energy's secondary systems, and the business knowledge of subject matter experts who are involved in providing those services.

Methodology and Assumptions

Essential Energy's existing PTJs have been classified as outlined in the table below:

Service subcategory	PTJ Type	Fee Calculation
De-energisation - Disconnection/ Reconnection - Disconnection Completed	DNP Disconnect Visit B2B Disc Non Pay/Fuse	20 minutes on site plus travel - uplifted to cover re-energisation
De-energisation - Disconnection/ Reconnection - Technical Disconnect	Temporary Disconnect Reconnect	20 minutes on site plus travel - uplifted to cover re-energisation
De-energisation - Disconnection/ Reconnection - Pillar/Pole - Disconnection Completed	DNP Poletop Disconnect At Pole B2B Final Read/Disc at Pole B2B Disc Non Pay/Pole	1 hour plus travel (2 employees) - uplifted to cover re-energisation
De-energisation - Disconnection/ Reconnection - Vacant Property reconnect/disconnect	Final + Main Switch Final + Pull Fuse NW Final + Pull Fuse Vacant De-Energise Use on Inactive mtr B2B De-energise B2B Final Read/Fuse	20 minutes on site plus travel - uplifted to cover re-energisation
Re-energisation - Disconnection/Reconnection - Disconnection	Re-En after DNP B2B Re-en after DNP Re-En Aft Illegal Co	No fee calculated - uplift included in de-energisation fee to cover re-energisation

Completed (Re-en)		
Re-energisation - Disconnection/Reconnection - Pillar/Pole - Disconnection Complete (Re-en)	Reconnect Poletop New Conn-Reconn (Service)	No fee calculated - uplift included in de-energisation fee to cover re-energisation
Re-energisation - Reconnection/Disconnection outside of business hours	Re-en After Hours Re-en After DNP A/Hrs B2B Re-en After Hours	20 minutes on site plus travel (using overtime labour rates)
Re-energisation - Vacant property reconnect/disconnect (Re-en)	NW Re-energisation Re-Energisation B2B Re-energise B2B Re-en Read Req	No fee calculated - uplift included in de-energisation fee to cover re-energisation
Site Visit - Disconnection - site visit		15 minutes plus travel Wasted visits associated with: "De-energisation - Disconnection/Reconnection - Disconnection Completed", "Re-energisation - Disconnection/Reconnection - Disconnection Completed (Re-en)" and "De-energisation - Disconnection/ Reconnection - Technical Disconnect"
Site Visit - Disconnection/Reconnection - Pillar/Pole - site visit		15 minutes plus travel Wasted visits associated with: "De-energisation - Disconnection/ Reconnection - Pillar/Pole - Disconnection Completed" and "Re-energisation - Disconnection/Reconnection - Pillar/Pole - Disconnection Complete (Re-en)"
Wasted Visit - Reconnection/Disconnection outside of business hours		Fee charged at same rate as completing "Re-energisation - Reconnection/Disconnection outside of business hours"
Wasted Visit - Move in Move out reads & special reads (wasted visit)		Fee charged at same rate as completing "Move-in Move-out read & Special Read"
Wasted Visit - Vacant Property reconnect/disconnect (wasted visit only)		15 minutes plus travel Wasted visits associated with: "De-energisation - Disconnection/ Reconnection - Vacant Property reconnect/disconnect" and "Re-energisation - Vacant property reconnect/disconnect (Re-en)"
Off Peak Conversion	Check Tariff (Enquiry) HW Ch CL1 to CL2 HW Ch CL2 to CL1 HW Ch CL2r to Dubbo HW Ch CL3 to CL2 Nth HW Ch CL3 to CL1 Nth B2B Change Controlled Load B2B ChangeTariff	10 minutes plus travel Re-programming only
Move-in Move-out read & Special Read	Final Read-Leave Conn (new Cust) Special reading-Elect Chargeable Check read Non Chargeable Check read B2B Checkread B2B 915 Special Read	10 minutes plus travel

	B2B Check Read Final Reading Only Final + New Occupant Retailer Churn	
Meter Test	Check Meter (Enquiry) B2B Meter Test	2 hours and 30 minutes plus travel (two visits) Usually remove meter and send for testing
Other Wasted Visits		15 minutes plus travel Wasted visits associated with: “Off Peak Conversion” “Meter Test”

Historical volumes have been sourced from different systems over the time periods required due to various reporting changes.

Wasted visit volume was calculated based on reporting from 2012/13 which provided a wasted visit percentage for each PTJ type. The same percentage has been applied to all years (historical and forecast).

Travel time was estimated using 2012/13 volumes. Total project hours were taken from two project types - Non Routine Meter Reads (11105) and Metering and Load Control (11100). Estimated labour hours (provided by subject matter experts) were applied to each PTJ type and the remainder (total actual project hours - estimated project hours) divided against the total volume of PTJs to provide an average travel time of 27 minutes per PTJ.

To calculate the historical expenditure for each service subcategory, the volumes were translated into labour hours (based on labour estimates including travel). The labour hours totals for each subcategory were then represented as percentages of total hours estimated. These percentages were applied to the total expenditure for Non-Routine Meter Reads and Metering & Load Control project types to provide estimated expenditure for each subcategory.

For the remaining fee-based services Essential Energy has estimated actual service volumes, from the historical revenue recorded in its General Ledger wherever possible. The business has supplemented and verified these estimates using secondary business systems such as the ‘Contestable Works Database’.

Subject matter experts, who are familiar with the work associated with each service, have made general assumptions around the average time required to complete each service. In addition, the estimators have made allowance for average material and direct costs per service (including fleet where travel is involved). In the case of fleet costs, the estimate applies the organisations standard fleet rate per labour hour.

For new proposed fees (where no history of revenue exists), subject matter experts have estimated the annual volume of services provided, using limited business records and general business knowledge.

This response includes the detailed work papers (and related assumptions) used to make these estimates.

Description of Fee Based and Quoted Services

Essential Energy has provided detailed models for each ancillary service fee it proposes to charge for the regulatory period. The models include: -

- A detail description of each fee and the work involved in providing the proposed service

- The basis on which the service will be billed - fee based or quoted
- An indication of the costs incurred in providing the service
- The detail calculation used to arrive at the charge

The general methodology used to set all of the proposed Ancillary Service Fees is explained in the included Essential Energy ANS Pricing Approach document.

Each model also includes:-

- The labour classification
- The number of workers required to undertake the task and deliver the service
- The average time required to complete the task and deliver the service
- Details of materials that have been included in the calculation

The relevant documents are:

- Attachment 8.8 – Ancillary Network Services Proposal
- Attachment 8.9 – Ancillary Network Services Model
- Attachment 8.10 – Charges for Ancillary Network Services

Use of estimated information

As noted above, due to a lack of accounting records, Essential Energy has been required to estimate the actual cost (and in some cases the volume) of ancillary services provided.

Essential Energy does keep detailed revenue totals for each service, and it has used these records as a basis for volume & cost estimation wherever possible.

There is insufficient information available however to calculate detailed service costs without making general assumptions and estimates.

Reliability of information

Essential Energy advise that due to the lack of detail costing records, and the level of assumptions and estimation required, this information should be regarded as broadly indicative of Service Fee costs and volumes only. Therefore the data should be treated with caution when using this for benchmarking or decision making purposes.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 5.1 - Material Projects

5.1.1 Projects in forthcoming regulatory control period*

Compliance with requirements of the notice

Information provided in this table about the projects or programs listed is based on the definition given for a *Material Project*, (a network Project with life cost >$5M). Both continuing and future projects are listed, and are consistent with the AER definition of a '*Project*' with '…expected start and finishing dates...'

The projects listed only cover CAPEX projects.

Source of information

The information presented is sourced from the Essential Energy "Portfolio Investment Plan (PIP) list" (March 2014) as submitted to Networks NSW. (Note the 'Unique Identifier' corresponds to the "PIP Number" of the "PIP list").

Information pertaining to the Regulatory Test refers, where necessary, to either the previous regulatory test requirements, that is, prior to 31 December 2013 or the new Regulatory Test – Distribution (RIT-D), post 31 December 2013.

Documentation cited regarding Regulatory Test and Business Case approvals are collated from various sources including, yet not limited to: Peer Review database, Network Planning database, and the Project Management Office (PMO) - Project Approvals electronic register, and are as authorised/ endorsed by the appropriate organisational governance/delegated approval level under Essential Energy and Networks NSW, as appropriate.

Methodology and Assumptions

The information on projects listed is limited to CAPEX projects.

Forecasts of project timing (fiscal year) and yearly expenditure values ($'s) are actuals derived from what are estimates in the "PIP List". (Dollars are presented as 'real 2013/14' dollars).

Use of estimated information

'Forecast Yearly Expenditure' amounts (real $ '000), are based on either robust building block estimates or in specific cases, in accordance with reliable historical data for process/plant/equipment/labour unit rates, so as to better approximate the expenditure depending upon its type/nature.

Dates provided are best pragmatic estimates in accordance with prudent project management principles, except for those provided with reference to actual completion dates for regulatory tests and business case approvals.

Reliability of information

Data/information provided is considered reliable.

5.1.2 Projects in current regulatory control period

Compliance with requirements of the notice

Information provided in this table about the projects or programs listed is based on the definition given for a *Material Project*, (a network Project with life cost >$5M). Both current and continuing projects (within the forthcoming regulatory control period) are listed, and are consistent with the AER definition of a '*Project*' with '…expected start and finishing dates...'.

The projects listed only cover CAPEX projects.

Please note: The Column 'X' "Total" formula in the AER template provided appears to be in error. It should be the 'difference' between the two columns not the 'addition' thereof.

Source of information

The information presented is sourced from the Essential Energy 'Primavera' project management system. (Note the 'Unique Identifier' is a unique designation related to the project, however where the project overlaps into the 'Forecast regulatory control period' (Table 5.1.1), their 'Unique Identifier' corresponds to the "Portfolio Investment Plan (PIP) Number" of the "PIP list").

Information pertaining to the Regulatory Test refers, where necessary, to the Regulatory Test requirements in accordance with the National Electricity Rules (NER) prior to 31 December 2013.

Documentation cited regarding Regulatory Test and Business Case approvals are collated from various sources including, yet not limited to: Peer Review database, Network Planning database, and the Project Management Office (PMO) - Project Approvals electronic register, 'Objective' and other corporate document repositories.

Methodology and Assumptions

The information on projects listed is limited to CAPEX projects.

Project timing (fiscal year) and yearly expenditure values ($'s) are actuals taken directly from the relevant Business Case Approval documentation, or actuals of the 'known' expenditures from the 'Primavera' project management system. (All dollar figures are presented as 'nominal' dollars).

Dates referred to are 'actual' recorded.

Use of estimated information

In some instances where the Business Case Approval documentation does not define a fiscal year timing profile, an estimate of the yearly expenditure profile has been made from the available project delivery information contained in 'Primavera'. This is only done for the 'known' yearly expenditure columns. Hence, the 'Approved' expenditure columns in these cases include only one total figure. In a few instances, an approval may cover several projects. Where this occurs, a note in the 'business case approval' column is made.

Reliability of information

Data/information provided is considered reliable.

5.1.3 Non-network asset projects in the forthcoming regulatory control period*

Property related

Compliance with requirements of the notice

In the following subheadings Essential Energy demonstrates how the information provided is consistent with the requirements of this Notice. Information provided in this table about the projects or programs listed is based on the definition given for a *Material Project*, (a network Project with life cost >$2M)

Source of information

Data has been sourced from the following areas:

- Condition Assessment Rectification and Compliance Program Delayed Start Non-system Projects Corporate Investment Document
- Scheduled Element Replacement Program Delayed Start Non-system Projects Corporate Investment Document
- Staff Relocation and Facility Rationalisation Program Delayed Start Non-system Projects Corporate Investment Document
- Zone Substation Centralised Storage Facility Delayed Start Non-system Projects Corporate Investment Document
- Information provided by Network Development Transmission Routes

Methodology and Assumptions

The methodology and assumptions are contained within the Corporate Investment Documents listed above.

Use of estimated information

Not applicable as factual data was used from Corporate Investment documents and data supplied by Network Development Transmission Routes.

Reliability of information

Essential Energy advise that this information provided in this section is reliable, obtained from Corporate Investment documents and data supplied by Network Development Transmission Routes.

ICT

Compliance with requirements of the notice

Information provided in this table about the projects or programs listed is based on the definition given for a *Material Project*, (a network Project with life cost >$2M)

Source of information

Data has been sourced from the following areas:

- ProSight (Portfolio Management tool) – All sunk costs and forecasts.
- Primavera (Project Scheduling tool) – all approval dates from budget log.
- GSS Project Document Store (controlled document store for ICT approved project documentation) – Capex/Opex budget breakdowns, on-going Opex costs.

Methodology and Assumptions

The following assumptions have been made when compiling this data:

1. Proposed Start Date: the date the first approval to commence work on a project occurred via approval of a Concept Brief or Investment Submission Form or an Approval to Spend.
2. Proposed Commissioning Date: the approved finish date from the last approved document.
3. Business Case/Corporate Investment Document Approval Date: the date the major funding request was approved via a Business Case/Corporate Investment Document. A project may have more than 1 Business Case/Corporate Investment Document during its life. Only the primary Business Case/Corporate Investment Document is listed.
4. The Business Case/Corporate Investment Document may not be the final funding request for a project. Variations may occur after the Business Case/Corporate Investment Document has been approved. This may be via an Exception Report or a Supplementary Corporate Investment Document.
5. Operating Expenditure may relate to either:
   - Operating Expenditure within a project and typically applies to feasibility activities or training.
   - Any FTE financial impacts resulting from a project.
6. Maintenance Expenditure: any on-going Operating Expenditure resulting from a project in the nature of licenses and maintenance and support agreements with external service providers.
7. Maintenance Expenditure: derived from the approved Business Case/Corporate Investment Document at the time of approval. All durations shown for Maintenance Expenditure are as reflected in the approved Business Case/Corporate Investment Document. No additional information is provided regarding the on-going variations for maintenance and support costs.

Use of estimated information

Essential Energy has used estimated financial information for Table 5.1.3 for the Unique Identifier "ICT AMP".

- An estimate only is provided at this time as the scope, duration, timing and thereby cost of this program of work is yet to be finalised prior to submission for approval.
- The estimate is based on the sub-elements identified within the ICT Asset Management Plan for the period 2015-2019.
- The estimates are based on historic evidence and current market data, given the information sought in this Notice. A Board paper and Corporate Investment Document are currently being prepared to seek approval for the ICT AMP.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

5.1.4 Non-network asset projects in the current regulatory control period

Property related

Compliance with requirements of the notice

Information provided in this table about the projects or programs listed is based on the definition given for a *Material Project*, (a network Project with life cost >$2M)

Source of information

Data has been sourced from the following areas:

- PeopleSoft

- Financial Reports
- Approved Business Cases
- Builder's Drawdown Notices

Methodology and Assumptions

Information provided ties back to factual historical financial reports, approved business cases and builder's drawdown notices for future works in the remainder of the 2013/14 year.

Note that PS-2010/14-PROG-03 Facilities Management Capital Works (Minor Unplanned) was made up of multiple small business cases and pre-approved works which are too numerous to add up to complete the pre-approved budget numbers totalling over $16.5m over 5 years. The majority of these works arose because of unexpected damage or asset failure and were repaired as soon as practicable after the event in order to maintain safe working environments.

Use of estimated information

Estimates contained within the approved business cases and builder's drawdown notices for future works in the remainder of the 2013/14 year have been used.

Reliability of information

Essential Energy advise that the information provided is reliable, sourced from historical financial reports, approved business cases and builder's drawdown notices.

ICT

Compliance with requirements of the notice

Information provided in this table about the projects or programs listed is based on the definition given for a *Material Project*, (a network Project with life cost >$2M)

Source of information

Data has been sourced from the following areas:

- ProSight (Portfolio Management tool) – All sunk costs and forecasts.
- Primavera (Project Scheduling tool) – all approval dates from budget log.
- GSS Project Document Store (controlled document store for ICT approved project documentation) – Capex/Opex budget breakdowns, on-going Opex costs.

Methodology and Assumptions

The following assumptions have been made when compiling this data:

1. Proposed Start Date: the date the first approval to commence work on a project occurred via approval of a Concept Brief or Investment Submission Form or an Approval to Spend.
2. Proposed Commissioning Date: the approved finish date from the last approved document.
3. Business Case/Corporate Investment Document Approval Date: the date the major funding request was approved via a Business Case/Corporate Investment Document. A project may have more than 1 Business Case/Corporate Investment Document during its life. Only the primary Business Case/Corporate Investment Document is listed.
4. The Business Case/Corporate Investment Document may not be the final funding request for a project. Variations may occur after the Business Case/Corporate Investment Document

has been approved. This may be via an Exception Report or a Supplementary Corporate Investment Document.

5. Operating Expenditure may relate to either:
6. Operating Expenditure within a project and typically applies to feasibility activities or training.
7. Any FTE financial impacts resulting from a project.
8. Maintenance Expenditure: any on-going Operating Expenditure resulting from a project in the nature of licenses and maintenance and support agreements with external service providers.
9. Maintenance Expenditure: derived from the approved Business Case/Corporate Investment Document at the time of approval. All durations shown for Maintenance Expenditure are as reflected in the approved Business Case/Corporate Investment Document. No additional information is provided regarding the on-going variations for maintenance and support costs.

Use of estimated information

Essential Energy has not used estimated financial information for Table 5.1.4.

Reliability of information

The data provided is considered to be reliable

5.1.5 New customer connections projects in forthcoming regulatory control period*

Compliance with requirements of the notice

Essential Energy has assumed that any network related 'new customer connections projects' relate only to individual major customer (load or generator) connection projects.

Based on the definition given for a *Material Project*, (a network Project with life cost >$5M), and the assumption that new customer connections projects relate only to individual major customer (load or generator) connection projects, then at the time of preparation of this RIN, Essential Energy could not foresee any network related new customer connections projects that meet the threshold criteria in the forthcoming regulatory control period.

Consequently, the data is blank, as all large connections are fully funded by the connection proponents or customers.

5.1.6 New customer connections projects in the current regulatory control period

Compliance with requirements of the notice

Essential Energy has assumed that any network related 'new customer connections projects' relate only to individual major customer (load or generator) connection projects.

Based on the definition given for a *Material Project*, (a network Project with life cost >$5M), and the assumption that new customer connections projects relate only to individual major customer (load or generator) connection projects, then at the time of preparation of this RIN, Essential Energy could not identify any network related new customer connections projects that meet the threshold criteria in the current regulatory control period.

Consequently, the data is blank, as all large connections are fully funded by the connection proponents or customers.

Worksheet 5.2 - Asset Age Profile

5.2.1 Asset age profile

Poles

Compliance with requirements of the notice

The information provided lists the number of poles owned by Essential Energy as well as privately owned poles which are maintained by Essential Energy.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- Essential Energy and Private owned poles have been included. Private assets included as these are private poles that Essential Energy inspects and in some cases maintains.
- Includes assets categorised in WASP as 'Poles'
- In Service poles have only been included.
- Staked Poles have been determined by those In-Service poles that have had a 'Pole – Reinstate' work task recorded against them.
- Age is determined from the pole's 'Date Installed'. Those Poles that do not have a 'Date Installed' have been prorated across the existing asset age profile.
- Pole Material is determined from the pole's 'Pole Material' and 'Pole Type' attributes as follows:

Pole Material	Pole Type	Material
Blank	Blank	Wood
Blank	Copper Chrome Arsenic	Wood
Blank	Low Temperature Creosote	Wood
Blank	Pigment Emulsified Creosote	Wood
Blank	Pressure Impregnated	Wood
Unknown	Blank	Wood
Unknown	Copper Chrome Arsenic	Wood
Unknown	Low Temperature Creosote	Wood
Unknown	Pigment Emulsified Creosote	Wood
Unknown	Pressure Impregnated	Wood
Timber	Blank	Wood
Timber	Copper Chrome Arsenic	Wood
Timber	Copper Chrome Napthenate	Wood
Timber	Low Temperature Creosote	Wood
Timber	Pigment Emulsified Creosote	Wood
Timber	Pressure Impregnated	Wood

Concrete		Concrete
Steel		Steel
Tower		Steel
Aluminium		Steel
Stobie		Stobie
Composite		Fibre Composite

- Voltage is determined from the pole's 'Highest Voltage' and 'Pole Function' attributes as follows:

Pole Function	Highest Voltage	Voltage
Bollard Pole	Blank	Bollard - None
HV/LV Pole	Blank	11kV
HV Pole	Blank	11kV
LV Pole	Blank	LV
Street Light Column	Blank	LV
Transmission/HV Pole	Blank	66kV
Transmission/HV/LV Pole	Blank	66kV
Transmission/LV Pole	Blank	66kV
Transmission Pole	Blank	66kV
	Bollard – None	Bollard - None
	6.35	11kV
	6.6	11kV
	11	11kV
	22	22kV
	12.7	12.7kV
	19.1	19.1kV
	33	33kV
	66	66kV
	132	132kV

- If the asset voltage is blank or 'Unknown' then the asset's maintenance area primary voltage is used instead (determined from Smallworld data).

Use of estimated information

Essential Energy has used estimated information for the pole material when there is no material listed for the pole. The estimation of using the pole type and pole function gives a fairly accurate estimation. Any poles without a 'Date Installed' have been prorated across the existing asset age profile.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Transformers

Compliance with requirements of the notice

The information provided includes distribution transformers owned by Essential Energy that are currently in use.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

Total = [Distribution Transformers] + [Zone Substation Auxiliary Transformers] as determined below:

<u>Distribution Transformers</u>

- Only Substation Sites with an Owner = 'Essential Energy'
- All Transformers that are currently in use (In Service)
- Includes SWER Isolators and Step Up/Down Transformers. This varies to table 3.5 Physical Assets.
- Voltage has been determined from the asset's 'Primary Voltage'.
- 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 been required 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
  - if kVA is still undetermined then kVA is estimated as:

Ground or Chamber Substation < 22kV	<=60kVA
Ground or Chamber Substation >= 22kV	<=15MVA
All Others	<=60kVA

  - for larger transformers (Ground and Chamber >= 22kV) the kVA determined above has been converted to MVA by dividing by 1000 for input into the RIN template.
- Mounting Type was determined based on 'Construction Type' as follows:
  - 'Pole Substation','2 Pole Platform Substation', 'Supported Platform Substation' = Pole Mounted

        - ‘Ground Substation’, 'Chamber Substation' = Ground Outdoor/Indoor Chamber Mounted
        - 'Pad/Kiosk Substation' = Kiosk Mounted

    If ‘Construction Type’ is blank then ‘Pole Mounted’ was assumed (note this was only required in < 0.5% of cases).

- Phases was determined based on the asset Phases attribute as follows:
    - ‘HV1’ = Single Phase
    - Else Multiple Phase
- Year has been obtained from the Substation Site's ‘Date Constructed’.
  If this is not available, then Year has been derived as follows (note this has only been required in 2% of cases):
    - if Substation Site ‘Date Constructed’ is blank, then use most recent ‘Date Manufactured’ from the Substation Site’s associated children Transformer(s).
    - Those Substation Sites that do not have a ‘Date Constructed’ or a Transformer with a ‘Date Manufactured’ have been prorated across the existing asset age profile.
- Distribution transformers in stores have not been included.

Zone Substation Auxiliary Transformers

- ZS Auxiliary Transformers with a Service Status indicating it is in service or will be in future ('In Service', 'Not Applicable', 'Out of Service', 'System Spare', 'Under Construction', 'Under Repair')
- Only ZS Auxiliary Transformers with an Owner = ‘Essential Energy’
- All ZS Auxiliary Transformers have been categorised as ‘Ground Outdoor/Indoor Chamber Mounted’.
- All ZS Auxiliary Transformers have been categorised as ‘Multiple Phase’.
- Voltage has been obtained from the ZS Auxiliary Transformer’s ‘Primary Voltage’. If ‘Primary Voltage’ is blank then ‘<22kV’ has been assumed. This was only required in < 0.5% of cases.
- kVA has been obtained from the ZS Auxiliary Transformer ‘Rating (kVA)’.
  If this is not available, then kVA has been derived as follows:
    - if ZS Auxiliary Transformer ‘Rating (kVA)’ is blank, then use ‘Primary Voltage’ as follows:
      < 22kV = ‘>60kVA and <=600kVA’

      >= 22kV = ‘<=15MVA’
    - if ‘Primary Voltage’ is blank or ‘Unknown’ then a kVA of ‘>60kVA and <=600kVA’ has been assumed
    - for larger transformers (Ground and Chamber >= 22kV) the kVA determined above has been converted to MVA by dividing by 1000 for input into the RIN template.
- Year has been obtained from the ZS Auxiliary Transformer’s ‘Year of Manufacture’.
  If this is not available, then Year has been derived as follows:
    - if ZS Auxiliary Transformer ‘Year of Manufacture’ is blank, then use the ‘Commissioning/Install Date’.
    - Those ZS Auxiliary Transformers that do not have a ‘Year of Manufacture’ or ‘Commissioning/Install Date’ have been prorated across the existing asset age profile.

Use of estimated information

- Essential Energy has used estimated information when there is no ‘Date Constructed’ for the Substation Site or ‘Date Manufactured’ on the child Transformer(s) for Distribution Substations.

- Essential Energy has used estimated information when there is no 'Year of Manufacture' or 'Commissioning/Install Date' for the ZS Auxiliary Transformers as per the existing age profile.
- Essential Energy has used estimated information when there is no 'Total kVA' for the Substation Site. 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.
- Essential Energy has used estimated information when there is no 'Rating (kVA)' for the ZS Auxiliary Transformers. This was only performed in approximately 17% 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 Voltage.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Switchgear

Compliance with requirements of the notice

The information provided lists Switch Gear assets that are owned by Essential Energy and are currently in use. Switch gear includes Reclosers, Sectionalisers, Disconnecting Links, Fuses, Air Break Switches, Load Break Switches, Fuses/Switches that are part of Substations and Zone Substation Circuit Breakers.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- Circuit Breakers = Reclosers.
- Operational Switches = Sectionalisers; Disconnecting Links; Air Break Switches; Load Break Switches.
- All assets are owned by Essential Energy (no Privately owned assets)
- Service Status = 'In Service'.
- Age is determined by the assets 'Constructed Date'. If this is not available then the age is determined from the parent pole's 'Date Installed'.
- If the asset voltage is blank or 'Unknown' then the parent pole's voltage is used. If the parent's voltage is unknown then the asset's maintenance area primary voltage is used instead (determined from Smallworld data).

These figures were determined in three parts:

1. Extract data/age profile for Distribution Switchgear currently recorded in WASP.
2. Extract data/age profile for Zone Substation Circuit Breakers recorded in WASP.
3. Estimate the number of Fuses/Switches that are part of Substations (both pole mounted and ground/enclosed substations) that are not discretely recorded in WASP.

The results from these queries/estimations were then combined. The logic for each of these three parts is detailed below:

1. Extract data/age profile for Distribution Switchgear currently recorded in WASP

SQL Logic:

- Circuit Breakers = assets with a category of ‘Recloser Site’.
- Operational Switches = assets with a category of ‘Sectionaliser Site’, ‘Disconnecting Link’, ‘Air Break Switch’, ‘Load Break Switch Site’.
- Fuse = assets with a category of ‘Fuse - O/H’
- Only assets with an owner of Essential Energy
- Service Status = ‘In Service’
- Year has been determined by the asset’s ‘Constructed Date’.
  If this is not available, then Year has been derived as follows:
  - If the ‘Constructed Date’ is blank, then use the parent pole’s ‘Date Installed’ if available/applicable.
  - Those assets that do not have a ‘Constructed Date’ or a parent pole with a ‘Date Installed’ have been prorated across the existing asset age profile.
- Voltage has been determined from the asset’s ‘Primary Voltage’.
  If the asset voltage is blank or ‘Unknown’ then the Voltage has been derived as follows:
  - If no asset Voltage is available, the parent pole’s ‘Highest Voltage’ is used if available/applicable.
  - If the parent pole’s Highest Voltage is unknown then the asset’s Maintenance Area primary voltage is used instead (determined from Smallworld data).

2. Extract data/age profile for Zone Substation Circuit Breakers recorded in WASP

SQL Logic:

- ZS Circuit Breakers with a Service Status indicating it is in service or will be in future ('In Service', 'Open Point', 'System Spare', 'Under Construction', 'Out of Service', 'Not Applicable', or 'Under Repair')
- Only ZS Circuit Breakers with an Owner = ‘Essential Energy’
- All ZS Circuit Breakers have been categorised as ‘Circuit Breaker’
- Voltage has been obtained from the ZS Circuit Breaker’s ‘Primary Voltage’. If ‘Primary Voltage’ is blank then ‘<=11kV’ has been assumed. This was only required in < 0.05% of cases.
- Year has been obtained from the ZS Circuit Breaker’s ‘Year of Manufacture’.
  If this is not available, then Year has been derived as follows (this was required in 7% of cases):
  - If ZS Circuit Breaker ‘Year of Manufacture’ is blank, then use the ZS Circuit Breaker’s ‘Commissioning/Install Date’.
  - If the ZS Circuit Breaker’s ‘Year of Manufacture’ and ‘Commissioning/Install Date’ is blank then the parent Zone Substation’s ‘Year of Manufacture’ was used.
  - Those ZS Circuit Breakers that do not have a ‘Year of Manufacture’ or ‘Commissioning/Install Date’ and whose parent Zone Substation does not have a ‘Year of Manufacture’ have been prorated across the existing asset age profile.

3. Estimate the number of Fuses/Switches that are part of Substations and not discretely recorded in WASP

Fuses/Switches that are part of substation sites (both pole mounted and ground/enclosed) are not typically discretely recorded in WASP. These were estimated as follows:

Pole mounted Substation Sites:

i. The quantity of pole mounted Substation Sites was determined from WASP. It was determined there are approximately 128,500.

ii. The average quantity of fuses for overhead/pole mounted Substation Sites was determined. Based on the existing configuration of Substation Sites across Essential Energy's network it was determined that on average there are 2.5 fuses per Substation Site; 1.5 LV fuses and 1 HV fuse per Substation Site.

iii. The estimated quantity of fuses for overhead/pole mounted Substation Sites was determined by multiplying step 1 and 2:
   - LV Fuses = 1.5 x 128,500 = 192,750
   - HV Fuses = 1 x 128,500 = 128,500

iv. The profile of Primary Voltage for existing pole mounted Substation Sites was determined from WASP as follows:

Voltage	Count	Percentage	Maping
11kV	86928	67%	<= 11kV
12.7kV	3490	3%	>11 and <=22kV
19.1kV	5235	4%	>11 and <=22kV
22kV	33522	26%	>11 and <=22kV
33kV	1342	1%	>22 and <=33kV

Split	
<=11kV	67%
>11 and <=22kV	32%
>22 and <=33kV	1%
	100%

v. These percentages were applied to the estimated counts in step 3 to determine the quantities per voltage group:
   - LV Fuses
     - LV = 100% x 192,750 = 192,750
   - HV Fuses
     - <=11kV = 67% x 128,750 = 86,095
     - >11kV and <=22kV = 32% x 128,750 = 41,120
     - >22kV and <=33kV = 1% x 128,750 = 1,285

vi. All of these were categorised as 'Fuse'

Ground Mounted/Enclosed Substation Sites:

i. The quantity of ground mounted/enclosed Substation Sites was determined from WASP. It was determined there are approximately 6,250.

ii. The average quantity of fuses/switchgear for ground mounted/enclosed Substation Sites was determined. Based on the existing configuration of these Substation Sites across Essential Energy's network it was determined that on average there are 6 fuses/switches per Substation Site; 4 LV fuses and 2 HV fuses per Substation Site.

iii. The estimated quantity of fuses for ground mounted/enclosed Substation Sites was determined by multiplying step 1 and 2:
   - LV Fuses = 4 x 6,250 = 25,000
   - HV Fuses = 2 x 6,250 = 12,500

iv. The profile of Primary Voltage and categorisation (fuse, circuit breaker or operational switch) for existing ground mounted/enclosed Substation Sites was determined from WASP as follows:

LV Switchgear

Category	Count	Percentage
Circuit Breaker	**2378**	**10.93%**
11kV	1	0.00%
LV	2377	10.93%
Fuse	**19376**	**89.07%**
22kV	7	0.03%
LV	19369	89.04%
(blank)		**0.00%**
(blank)		0.00%
Grand Total	**21754**	**100.00%**

Split	
LV Circuit Breaker	11%
LV Fuse	89%
	100%

HV Switchgear

Category	Count	Percentage
Circuit Breaker	**10352**	**24.84%**
11kV	6814	16.35%
22kV	1089	2.61%
33kV	51	0.12%
6.35kV	10	0.02%
LV	2377	5.70%
(blank)	11	0.03%
Fuse	**27971**	**67.12%**
11kV	7988	19.17%
22kV	502	1.20%
33kV	103	0.25%
LV	19373	46.49%
(blank)	5	0.01%
Operational Switch	**3351**	**8.04%**
11kV	1973	4.73%
22kV	1372	3.29%
LV	2	0.00%
(blank)	4	0.01%
(blank)		**0.00%**
(blank)		0.00%
Grand Total	**41674**	**100.00%**

Split	
11kV Circuit Breaker	35%
22kV Circuit Breaker	5%
11kV Fuse	41%
22kV Fuse	3%
11kV Operational Switch	10%
22kV Operational Switch	6%
	100%

v. These percentages were applied to the estimated counts in step 3 to determine the quantities per voltage group:

- LV Switchgear
  - LV Circuit Breaker = 11% x 25,000 = 2,750
  - LV Fuse = 89% x 25,000 = 22,250
- HV Switchgear
  - <=11kV Circuit Breaker = 35% x 12,500 = 4,375
  - <=11kV Fuse = 41% x 12,500 = 5,125

–	<= 11kV Operational Switch	= 10% x 12,500	= 1,250
–	>11kV and <=22kV Circuit Breaker	= 5% x 12,500	= 625
–	>11kV and <=22kV Fuse	= 3% x 12,500	= 375
–	>11kV and <=22kV Operational Switch	= 6% x 12,500	= 750

vi. The age profile of the equivalent category of the existing switchgear was then applied to each of these estimated counts to determine year/age.

Use of estimated information

Essential Energy has used estimated information for:

- Distribution Switchgear current recorded in WASP as follows:
    - the asset's age when there is no 'Construction Date' for that asset. The estimation uses the parent pole's 'Date Installed' if available which gives a fairly accurate estimation. If neither of these dates were available to determine age then the assets were aged as per the existing age profile.
    - the asset's voltage when there is no voltage listed for that asset. The estimation uses the parent pole's voltage or the Maintenance area's primary voltage which gives a fairly accurate estimation.
- Zone Substation Circuit Breakers recorded in WASP as follows
    - the asset's age when there is no 'Year of Manufacture' for that asset. The estimation uses the asset's 'Commissioning/Install Date' for the ZS Circuit Breaker. If neither of these dates were available to determine age then the assets were aged as per the existing age profile.
    - the asset's voltage when there is no voltage listed for that asset. The estimation assumes <=11kV in < 0.05% of cases.
- Distribution Switchgear that are considered part of Substation Sites and are not discretely recorded in WASP as follows has been entirely estimated based on knowledge of the network and existing data in WASP.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Public Lighting

Compliance with requirements of the notice

The information provided reports the number of public lighting luminaires and public lighting poles. Assets owned by Essential Energy and assets operated and maintained by Essential Energy but not owned by Essential Energy have been included.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- For the luminaire count - only Streetlights with an Owner = 'Essential Energy' or 'RTA' (which Essential Energy maintain) are included.
- For the dedicated streetlight pole count – only Streetlights that are owned by Essential Energy or Privately Owned but maintained by Essential Energy. No RTA poles.
- Only Streetlights with a Service Status = 'In Service'.
- Streetlights with a Lighting Category = 'Quarantined' were excluded.
- Streetlights with a Lighting Category = 'Traffic Route Lighting' are assumed to be Major Road. All else are classified as Minor Road.
- Assets with a category of 'Nightwatch Light' were excluded.
- Age is determined from the parent pole's 'Date Installed' attribute. If this does not exist then the street light's 'Connection Date' attribute is used to determine the age.
- Those assets that do not have a 'Date Installed' or a 'Connection Date' have been prorated across the existing asset age profile.
- The Mean Economic Life of 20 years is based on a decision made by NNSW for all 3 DNSPs, and is based on the manufacturers recommended useful and depreciable life of 20 years.

Use of estimated information

Essential Energy has used estimated information for the street light's age when there is no install date for the parent pole. When there is no install date the street light's 'Connection Date' is used which gives a fairly accurate estimation. Those assets that do not have a 'Date Installed' or a 'Connection Date' have been prorated across the existing asset age profile.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Regulators

Compliance with requirements of the notice

The information provided shows the number of Essential Energy owned Regulator Sites that are currently in use.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- Only Essential Energy assets included.
- Only In Service assets included.
- Includes assets categorised in WASP as 'Regulator Sites'.
- Age is determined from 'Date Constructed' attribute.
- If 'Date Constructed' is blank then the age is determined from the parent pole's 'Date Installed' attribute.
- Those assets that do not have a 'Date Constructed' or a parent pole 'Date Installed' have been prorated across the existing asset age profile.

- Voltage has been determined from the asset's 'Primary Voltage'.
  - If the asset voltage is blank, 'Unknown', '6.35kV', '66kV', '110kV' or '132kV' then the asset's maintenance area primary voltage is used instead (determined from Smallworld data).

Use of estimated information

Essential Energy has used estimated information for:

- The asset's age when there is no 'Date Constructed' for that asset. The estimation uses the parent pole's 'Date Installed' which gives a fairly accurate estimation.
- Those assets that do not have a 'Date Constructed' or a parent pole 'Date Installed' have been prorated across the existing asset age profile.
- The asset's voltage when there is no voltage listed for that asset. The estimation uses the parent pole's voltage or the Maintenance area's primary voltage which gives a fairly accurate estimation.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Reactors

Compliance with requirements of the notice

The information provided reports the number of Essential Energy owned Reactor Sites that are currently in use.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- Only Essential Energy assets included.
- Only In Service assets.
- Includes assets categorised in WASP as 'Reactor Sites'.
- Age is determined from 'Date Constructed' attribute.
  - If 'Date Constructed' is blank then the age is determined from the parent pole's 'Date Installed' attribute.
  - Those assets that do not have a 'Date Constructed' or a parent pole 'Date Installed' have been prorated across the existing asset age profile.
- All assets are assumed to be 'SWER' voltage.
- '25' kVAr is assumed if the 'kVAr' attribute on the Reactor Site was blank.

Use of estimated information

Essential Energy has used estimated information for:

- the asset's age when there is no 'Date Constructed' for that asset. The estimation uses the parent pole's 'Date Installed' which gives a fairly accurate estimation. Those assets that do not have a 'Date Constructed' or a parent pole 'Date Installed' have been prorated across the existing asset age profile.
- all assets are assumed to be 'SWER' voltage.

- ‘25’ kVAr is assumed if the ‘kVAr’ attribute on the Reactor Site was blank.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Line Fault Indicators

Compliance with requirements of the notice

The information provided shows the number of Essential Energy owned Line Fault Indicators that are currently in use.

Source of information

Data has been sourced from Essential Energy’s WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- Only Essential Energy assets included.
- Only In Service assets.
- Includes assets categorised in WASP as ‘Line Fault Indicator Sites’.
- Age is determined from the Line Fault Indicator Sites’s ‘Date Constructed’ attribute.
  - If ‘Date Constructed’ is blank then the age is determined from the parent pole’s ‘Date Installed’ attribute.
  - Those assets that do not have a ‘Date Constructed’ or a parent pole ‘Date Installed’ have been prorated across the existing asset age profile.
- Voltage has been determined from the asset’s ‘Primary Voltage’.
  - If the asset voltage is blank, ‘Unknown’, ‘6.35kV’, ‘66kV’, ‘110kV’ or ‘132kV’ then the asset’s maintenance area primary voltage is used instead (determined from Smallworld data).

Use of estimated information

Essential Energy has used estimated information for:

- the asset’s age when there is no ‘Connection Date’ for that asset. The estimation uses the parent pole’s ‘Install Date’ which gives a fairly accurate estimation. Those assets that do not have a ‘Date Constructed’ or a parent pole ‘Date Installed’ have been prorated across the existing asset age profile.
- the asset’s voltage when there is no voltage listed for that asset. The estimation uses the parent pole’s voltage or the Maintenance area’s primary voltage which gives a fairly accurate estimation.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Zone Sub Power Transformers

Compliance with requirements of the notice

The information provided reports the number of distribution Zone Sub Power Transformers owned by Essential Energy.

Source of information

Data has been sourced from Essential Energy's WASP database using SQL and grouping of data in Excel.

Methodology and Assumptions

SQL Logic:

- All ZS Power Transformer assets owned by Essential Energy.
- All ZS Power Transformers with a Service Status of 'In Service'.
- Excludes ZS Power Transformers with a Type of 'Regulators' or 'SWER Isolators'.
- MVA has been obtained from the 'Maximum Rating (MVA)' attribute. If blank it is assumed to be 5 MVA (note that this has occurred in <1% of cases).
- Year has been obtained from the ZS Power Transformer's 'Date Installed'. If this is not available, then Year has been derived as follows:
    - if ZS Power Transformer 'Date Installed' is blank, then use the 'Year of Manufacture' attribute from the ZS Power Transformer.
    - if ZS Power Transformer 'Year of Manufacture' is not available then it was classified as 'Unknown'.

Use of estimated information

- Essential Energy has used estimated information when there is no 'Date Installed' for the ZS Power Transformer. This was only performed in <1% of cases. The methodology used to estimate the date in these instances is considered to provide a reasonable approximation.
- Essential Energy has used estimated information when there is no 'Maximum Rating (MVA)' for the ZS Power Transformer. This was only performed 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.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Overhead conductors

Low voltage

Compliance with requirements of the notice

The information provided reports the number of overhead conductors owned by Essential Energy.

Source of information

Data has been sourced from the following:

Cable table: GIS (Smallworld) – Date installed, Purpose, Operating Voltage, Service Status, Owner, Nominal Length, Geometry (both Centreline and Actual Centreline combined), LV Service Type, Parent Substation

Substation Site table: GIS (Smallworld) – Asset Label, Location

Substation: Asset Management System (WASP) – Asset label, Date Constructed

Methodology and Assumptions

Smallworld Cables used in the analysis were filtered by:

Purpose = Overhead
Operating Voltage = LV
Owner = Essential Energy
LV Service type not equal to "Service"
Service Status = all

The Date Installed was converted into financial year. Lengths were summed by financial year and entered into the "quantity by year" cells of the table for the Category Overhead Conductors ≤1kV.

An estimate date installed was unachievable for a total of 554km of line – this length was spread across the age classes according to the age distribution.

Use of estimated information

Date Installed (Smallworld Cable)
Essential Energy has used a combination of actual and estimated information for the Date Installed attribute of lines. The probability of a record having a valid Date Installed value is greater in the years from 2003 onwards. Although legacy data has been used to fill in these values, valid dates are less likely to be available for lines installed by pre-amalgamation distributors. The collection of this information in the field at this stage is both difficult and would require a large undertaking.

If the line did not have a valid Date Installed, the Date Constructed of the substation related to that line (either by join or close by distance) was used as its Date Installed.

Assumptions

- That the Date constructed of the substation that is either joined to or nearest to the line is a reasonable estimate of the Date Installed of the line.
- That if the line was not joined to a parent substation (generally this join is only populated in Urban areas) that the LV line is likely to be fed from the nearest substation (by distance).

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Overhead conductors

Voltage 6.6kV to 33kV

Compliance with requirements of the notice

The information provided reports the number of overhead conductors owned by Essential Energy.

Source of information

Data has been sourced from the following:

Cable table: GIS (Smallworld) – Conductor Code, Date installed, Purpose, Operating Voltage, Phases, Service Status, Owner, Nominal Length, HV Feeder Label, Geometry

Pole table: GIS (Smallworld) – Date installed, Function

Methodology and Assumptions

Smallworld Cables used in the analysis were filtered by:

Purpose = Overhead
Operating Voltage = 6.6kV, 11kV, 12.7kV, 19.1kV, 22kV, 33kV
Phases = all
Owner = Essential Energy
Service Status = all

The Date Installed was converted into financial year. Lengths were summed by financial year and entered into the "quantity by year" cells of the table for the appropriate Category.

An estimate for the date installed was unachievable for a total of 121km of line in the categories >1kV to 33kV – this length was spread across the age classes according to the age distribution.

Use of estimated information

Date Installed (Smallworld Cable)

Essential Energy has used a combination of actual and estimated information for the Date Installed attribute of lines. The probability of a record having a valid Date Installed value is greater in the years from 2003 onwards. Although legacy data has been used to fill in these values, valid dates are less likely to be available for lines installed by pre-amalgamation distributors. The collection of this information in the field at this stage is both difficult and would require a large undertaking.

Poles dates were used to determine the date installed for lines which did not have a valid date. All cable objects in the GIS were grouped into spatially continuous sections according to HV Feeder/Conductor Code attributes. The resulting continuous sections of the same Feeder and Conductor Code combination were analysis to find the oldest pole date installed connected to it. All lines within the continuous section that did not have a valid date were then attributed with that oldest pole date installed year.

Assumptions:

- That any re-conducting would have been done in more recent times when data capture was more reliable. Cable objects entered into the GIS in recent times would already have a valid installed date and therefore would not have been subjected to this logic.
- That the oldest pole on any section indicates when the section was first built.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Overhead conductors

Voltage > 33kV

Compliance with requirements of the notice

The information provided reports the number of overhead conductors owned by Essential Energy.

Source of information

Data has been sourced from the following:

Cable table: GIS (Smallworld) – Date installed, Purpose, Operating Voltage, Phases, Service Status, Owner, Nominal Length, Geometry

Pole table: GIS (Smallworld) – Date installed, Function

Methodology and Assumptions

Smallworld Cables used in the analysis were filtered by:

Purpose = Overhead
Operating Voltage = 66kV, 110kV, 132kV, 220kV
Phases = all
Owner = Essential Energy
Service Status = all

The Date Installed was converted into financial year. Lengths were summed by financial year and entered into the "quantity by year" cells of the table for the appropriate Category.

Use of estimated information

Date Installed (Smallworld Cable)
Essential Energy has used a combination of actual and estimated information for the Date Installed attribute of lines. Date installed information was not available for all lines within the GIS. This is particularly the case with legacy data merged from pre-amalgamation distributors.

The population of the asset age profile of the subtransmission voltages was started as part of a data cleansing process for a Condition Based Risk Management (CBRM) project which predates this RIN. Initially, any feeder age information that was contained in the Transgrid data book was transferred into the GIS.

Each subtransmission feeder was considered on its own (note this may have contained a number of Smallworld Cable objects) in the following manner:

- Any cable object with a valid date was checked for known data issues and maintained in the majority of cases.
- The installation year of all the subtransmission poles attached to the cable object was used to calculate a mode year for a cable object or for the feeder as was appropriate.
- If the number of attached poles with that mode year value equalled more than 50% of the total poles it was considered enough evidence to date the feeder/cable object by this year.
- Local knowledge was sourced where available. Due to time constraints knowledge regarding feeders where evidence was not strong was prioritised.
- The lines dated in this manner were given 1/1/YEAR.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Underground cables

Low voltage

Compliance with requirements of the notice

The information provided reports the number of underground cables owned by Essential Energy.

Source of information

Data has been sourced from the following:

Cable table: GIS (Smallworld) – Date installed, Purpose, Operating Voltage, Service Status, Owner, Nominal Length, Geometry (both Centreline and Actual Centreline combined), LV Service Type, Parent Substation

Substation Site table: GIS (Smallworld) – Asset Label, Location

Substation: Asset Management System: (WASP) – Asset label, Date Constructed

Methodology and Assumptions

Smallworld Cables used in the analysis were filtered by:

Purpose = Underground
Operating Voltage = LV
Owner = Essential Energy
LV Service type not equalled to "Service"
Service Status = all

The Date Installed was converted into financial year. Lengths of the cables were summed by financial year and entered into the "quantity by year" cells of the table for the Category Overhead Conductors ≤1kV.

An estimated date installed was unachievable for a total of 963km of cable – this length was spread across the age classes according to the age distribution.

Use of estimated information

Date Installed (Smallworld Cable)
Essential Energy has used a combination of actual and estimated information for the Date Installed attribute of cable. The probability of a record having a valid Date Installed value is greater in the years from 2003 onwards. Although legacy data has been used to fill in these values, valid dates are less likely to be available for cables installed by pre-amalgamation distributors. The collection of this information in the field at this stage is both difficult and would require a large undertaking.

If the cable did not have a valid Date Installed the Date Constructed of the substation related to that cable (either by join or close by distance) was used as its Date Installed.

Assumptions:

- That the Date constructed of the substation that is either joined to or nearest to the cable is a reasonable estimate of the Date Installed of the cable.

- That if the cable was not joined to a parent substation (generally this join is only populated in Urban areas) that the LV cable is likely to be fed from the nearest substation (by distance).

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Underground cables

Other voltages

Compliance with requirements of the notice

The information provided reports the number of underground cables owned by Essential Energy.

Source of information

Data has been sourced from the following:

Cable table: GIS (Smallworld) – Date installed, Purpose, Operating Voltage, Service Status, Owner, Nominal Length, Geometry (both Centreline and Actual Centreline combined), LV Service Type, Parent Substation

Substation Site table: GIS (Smallworld) – Asset Label, Location

Substation: Asset Management System (WASP) – Asset label, Date Constructed

Methodology and Assumptions

Smallworld Cables used in the analysis were filtered by:

Purpose = Underground
Operating Voltage = LV
Owner = Essential Energy
LV Service type not equalled to "Service"
Service Status = all

The Date Installed was converted into financial year. Lengths of the cables were summed by financial year and entered into the "quantity by year" cells of the table for the Category Overhead Conductors ≤1kV.

An estimated date installed was unachievable for a total of 963km of cable – this length was spread across the age classes according to the age distribution.

Use of estimated information

Date installed (Smallworld Cable)
Essential Energy has used a combination of actual and estimated information for the Date Installed attribute of cables. The probability of a record having a valid Date Installed value is greater in the years from 2003 onwards. Although legacy data has been used to fill in these values, valid dates are less likely to be available for cables installed by pre-amalgamation distributors. The collection of this information in the field at this stage is both difficult and would require a large undertaking.

Where a valid date installed doesn't exist, an estimate was determined using the following methods:

1. Where an underground cable is connected from an overhead line to a single substation, allocate the installed date of the substation to the date installed of the cable.

2. Where the cable connected to a substation was part of a complex network of underground cable and substations, it needs to be considered by an operator. The aim is to allocate the cable with the substation installed date taking into consideration the way the network would have grown. This process will be continued over time.

3. Where an underground cable was not associated with substations it was individually assessed. Information used to estimate dates were: Construction plans, the age of the poles from which the underground cable was initiated, local knowledge etc.

Assumptions

- That the construction date of the substation is indicative of when the cable was installed.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Service lines

Compliance with requirements of the notice

The information provided reports the number of service lines owned by Essential Energy.

Source of information

Data has been sourced from the following:

Service Point data: GIS (Smallworld) – Premises joined

LV Cable data: GIS (Smallworld) - Date installed, Operating Voltage, Service Status, Owner, Nominal Length, Geometry (both Centreline and Actual Centreline combined), LV Service Type

Premise data: PEACE – Customer Type, Start-date

Methodology and Assumptions

Cables used in the analysis:

Purpose = all
Operating Voltage = LV
Owner = Essential Energy
LV Service Type = Service
Service Status = all

In Smallworld, premises are located at an object known as a Service Point. The Smallworld Cable (underground or overhead) connecting the Service Point to the network is attributed as 'Service'.

For each Service Cable find the following information:

a. Date Installed (estimated if required – see below)
b. Customer Type (estimated from premise data – see below)
c. Connection Complexity (Classify all the Service cable in the GIS as either Simple or Complex as per the definitions in Appendix G of the RIN document for both Residential and Commercial & Industrial types)

Convert the date installed into financial years. Sum the lengths of cables by financial year and entered into the “quantity by year” cells of the table for the appropriate Category.

There were a number of Service Points for which there were no Service Cables shown in Smallworld. The length of Service Cables for these Service Points were estimated (see below) and spread across the age classes according to the age distribution.

Assumptions:

- Essential Energy draws each of the Service lines in the GIS to a standard position within the land parcel. This is a central point at 6m depth from the edge of the land parcel from where the power is supplied. In some cases this may be altered (e.g. rural areas or where poles exist on the land parcel).

Notes:
17 Asset Refurbishment Categories have been added to the “Other” section at the bottom of Table 2.2.1 – *Replacement Expenditure, Volumes and Asset Failures by Asset Category*. Requirement 5.1 in Schedule 2 of the RIN Instructions states that Essential Energy “must provide corresponding age profile data in regulatory template 5.2 as per its respective instructions.”

We have not provided corresponding asset age profile for 13 of the refurbishment assets listed, as the expenditure plans reflected in table 2.2.1 is forecast for the years 2015-19, and Table 5.2.1 is retrospective from 2012/13.

We have not provided asset age profile for Land, Easements, or Salaries & Wages and Other Accruals, as it would not be appropriate to assign asset ages to these.

We have not provided an asset age profile for Customer Metering and Load Control, as the data does not currently exist in a suitable format, however we expect to be able to provide this information in future years.

Essential Energy does not have any Services that are not low voltage.
Essential Energy does not have any Services of type Subdivision.
All Essential Energy Commercial & Industrial customers are low voltage and are therefore connection complexity = Simple.

Use of estimated information

Date Installed (Smallworld Cable)
Essential Energy has estimated the date installed value for services. The location of services has not been uniformly populated in the system till recent years. The Customer, Premise, Substation group has been connecting the Service Point to the network in bulk over the past decade – date installed information was not included as part of this process. The collection of this information in the field at this stage is both difficult and practically impossible.

The start date for each premise was taken from Peace and applied to the Service Point so that it was attributed with the minimum start date of the premises joined to it. Each Service Cable was then attributed with the minimum start date of the Service Point it was attached to, or if this was null, the nearest Service Point (within 100m). The date installed on any of the Service cables was found to be unreliable at this stage so were only used if both the previous values were null.

Any Service Cable that could not be allocated a date was spread across the age classes according to the age distribution.

Assumptions

- That the start-date of the premise is an indication to the ages of the Service connecting that premise to the network.

- Peace data – start dates that had dramatically higher numbers of premises existed across the 2001/2002 dates. It is thought that these may have been a point at which data had been migrated from the previous distributor's system to Peace. These dates were removed from the analysis.

Customer Type
Information regarding the customer type that the cable is servicing is not maintained against the cable object in the GIS. Therefore this information was obtained from the premise information in Peace. If a Service Point in Smallworld had at least one residential Premise joined to it, it was considered residential. The Service Cable was attributed with the Customer Type value of the Service Point that it was attached to, or if this was null (because it was part of a complex service), the nearest Service point (within 100m). If both these values were null then it was assigned Residential. Data should improve as more Service Points are connected to the network with Service cable.

Length (Smallworld Cable)
Essential Energy has needed to estimate some lengths of Service Cable where currently no Service Cable exists in the GIS. The location of Service cable has not been uniformly populated in the system till recent years. The Customer, Premise, and Substation group has been connecting the Service Point to the network in bulk over the past decade. The collection of this information in the field at this stage is both difficult and would require a large undertaking.

The average length of Service Cable for the Commercial, Simple and Residential, Simple categories was used for those Service Points in which there was no Service Cable attached. These service points were all assumed to be of simple connection complexity. These addition lengths were spread across the age classes according to the age distribution.

Meters

Essential Energy has provided the age profile of Type 5 and 6 meters. The information provided is consistent with the total number of type 5 and 6 meters on 30 June 2013, of 1,457,634.

Source of Information:
The information has been based on records from the EDDIS system taken in 2012, and the 2012/13 records were added to this.

Methodology and Assumptions
Year profiles have been derived from meter purchase information provided from suppliers on when meters were manufactured and when they were sold to Essential Energy and its predecessors.

The Mean Economic Life is the financial depreciation rate for meters which is 25 years. This useful life for type 5 and 6 meters is currently set at 25 years due to the large volume of non-electronic meters in service.

Reliability of information

Information provided in Table 5.2. is considered reliable, apart from the Switchgear information which is based on assumptions and estimates.

Worksheet 5.3 - Maximum Demand at Network Level

5.3.1 Raw and weather corrected coincident MD at network level (summed at transmission connection point)

Compliance with requirements of the notice

This section shows the historical and forecast Coincident Maximum demand.

Source of information

The historical data is based on the maximum network demand as per the regulatory accounts and what was reported in the Economic Benchmarking RIN.

Methodology and Assumptions

The maximum network demand is determined by the sum of Essential Energy's Bulk Supply Points, Cross Border Supplies, and the inclusion of the Embedded Generators load at a half hourly level. From the half hourly data the Maximum Demand is determined with the date and time recorded. The actual dates and times of the occurrence have been reported in this table.

Use of estimated information

All forecast information is estimated.

Reliability of information

Historical maximum demand information is considered reliable

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 5.4 - Maximum Demand and Utilisation at Spatial Level

5.4.1 Non-coincident & coincident maximum demand

Compliance with requirements of the notice

Substation Definition:

Any substation (or a part of a substation) that transforms voltages that supply subtransmission networks (33kV and above), have been included as a subtransmission substation (STS). Any substation that transforms voltages (from 33kV and above) that supply distribution networks (33kV and below) have been included as a zone substation (ZS).

Substation Rating:

The AER definition of "Normal cyclic rating (for substations)" is "The maximum peak daily loading based on a given load cycle that a substation can supply each day of its life under normal conditions resulting in a normal rate of wear". Essential Energy defines the rating of a substation to meet the above definition to be 110% of the combined nameplate rating of all transformers within the substation. For example, if the substation only has one transformer the substation rating will be 110% of the nameplate rating of that transformer, or if it has two or more transformers the substation rating will be 110% of the combined nameplate rating of all the transformers.

Historical changes in substation rating have only been recorded where the information was readily available. For the vast majority of substations, the information about the changes in substation rating was not readily available. The amount of time to obtain that information could not be justified given the overall amount of information requested by the regulator and the short timeframe to supply all the requested information. For similar reasons, future changes in substation rating have not been provided.

Source of information

The individual STS data was obtained from demand meters (via IMDR). The individual zone substation data was obtained from demand meters (via IMDR) and from SCADA (via TrendSCADA).

Methodology and Assumptions

Change to timing arrangements:

The time periods in table 5.4.1 were nominated as financial years. However for forecasting purposes Essential Energy defines the time period for 2008/09 as the summer period of 2008/09 and the winter period of 2009 (e.g. from October 2008 to September 2009). An example of the reasoning behind this method is a system peak that occurred on 19 July 2011 which, using the financial year methodology was followed by a system peak that occurred on 18 January 2013. Clearly the dates meet the financial year requirement, i.e. 2011/12 and 2012/13, however from a seasonal perspective, they miss the periods of summer 2011/12 and winter 2012. Essential Energy does not consider the use of financial years to be adequate for use in forecasting.

Raw Adjusted MD:

<u>Non – coincident maximum demand</u>
The vast majority of STS's and ZS's have reliable data recording devices. A minor number of the very small ZS's have limited methods to record the peak demand such as recloser data or maximum demand indicators from which maximum demand has been derived. The raw data from each substation is sensitised visually to eliminate abnormal peaks to determine the true peak demand. For the STS's and ZS's, non-coincident actual demands only include the periods up to and including

summer 2012/13. For winter 2013 onwards, all values are forecast apart from a few exceptions for STS's which are a connection point to a TNSP. Those STS's will have actual winter 2013 values.

Essential Energy has only recorded the date and time of the STS and ZS actual raw demand peak from the period 2011/12 up to and including summer 2012/13. In previous years Essential Energy has only recorded the peak demands against winter and summer for a given year. Resource limitations prevent Essential Energy's ability to provide additional historical dates. It is estimated that at least 32 additional man days/260 man hours would be required to provide historical substation peak demand date.

<u>Coincident maximum demand</u>
Raw adjusted coincident maximum demand with the total system peak is of no use in forecasting and planning for network constraints in the distribution network. As such, Essential Energy does not record the coincident demand at the time of Essential Energy's system peak for its STS's or ZS's.

The only actual coincident demand figures obtained by Essential Energy occur at STS's which are connection points with a TNSP. All other figures have been extrapolated.

To extrapolate the coincident demand on an STS or ZS, weighting "factors" were obtained for individual TNSP connection points. Weighting "factors" were obtained in the following manner:

- The coincident demand at a connection point with a TNSP was divided by the raw demand at the connection point (using the last 5 years of data where possible).
- The resultants were then averaged over the last five years to obtain a weighting "factor" for summer and a weighting "factor" for winter.

The raw demand of the STS's and ZS's were then multiplied by their relevant TNSP connection points weighting "factor" to derive a coincident demand.

Adjustments – Embedded Generation:

Only discrete embedded generation units that impact the demand of the STS's or ZS's are included in the table. Rooftop photovoltaic generation are not shown as their impact is included in the actual and forecast demand of the individual ZS's. There are other discrete generation units that connect via Essential Energy's subtransmission network to a TNSP's connection point but they have no impact on the demand of Essential Energy owned STS's or ZS's.

Weather Corrected MD:

Essential Energy has no weather corrected data for 50% POE or 10% POE. Therefore no weather corrected data has been included as actual or forecast.

Date MD Occurred:

Essential Energy questions the accuracy or usefulness in the AERs request for forecasting the date and time of future system peaks.

Winter/Summer Peaking:

To allow Essential Energy to extrapolate future coincident substation demands, it has been assumed that the peak season would follow the same pattern as in previous years, i.e. alternating between winter and summer.

Actual generation capacity at the time of the peak demand on a STS (that is, not the Essential Energy system peak) was determined for the 2011/12 year for both the summer period and the winter period. Those values have therefore been chosen to represent the level of generation occurring at the time of system peak. Given the probability of accuracy of these figures for a given year, Essential Energy does not promote the use of these figures in forecasting system level peaks.

Due to the time available and effort required we are unable to reflect all change in capacity in transformers in the last 5 years and new projects.

Use of estimated information

Refer to above methodology and assumptions section for the use of estimated information.

Reliability of information

Most data for the 2012/13 year is considered reliable, however prior year information is based on assumptions and estimates and caution should be taken when using it for benchmarking or decision making purposes.

All forecast information is based on estimates and should be treated with caution, when using for decision making or benchmarking purposes.

Worksheet 6.1 - Telephone Answering

6.1.1 Telephone answering data

Compliance with requirements of the notice

The data reported is in line with the AER RIN requirements of the notice with contact centre generic data being used, however two reporting components (calls to payment lines and automated interactive services and calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator) were unable to be reported upon due to data availability and system constraints.

Whilst Essential Energy does have other phone lines, data within this section was from the fault line only.

Source of information

Data was sourced from a secondary reporting table (SIG Call Data - Excel) which has been manually updated with daily data from the main reporting tool called Symposium.

Methodology and Assumptions

Essential Energy used daily run historical call report data from a secondary reporting table (SIG Call Data – Excel illustrated below). The data was manually updated with daily data from the reporting tool, Symposium and covers the period from 1 July 2008 to 30 June 2012.

SIG Stats.xlsm - Microsoft Excel

	M	AT	AU	AV	AW	AX	AY	AZ	BE	BG	BP	BQ	BR	BS	BT	BU	BV	CA	CC
1		PORT MACQUARIE									QUEANBEYAN								
2		CUSTOMER							CENTRE		CUSTOMER							CENTRE	
3		ACTUAL	SIG	SIG NET	GE	GE NET	PLND OUT	Avg Abn	S/L	ASA	ACTUAL	SIG	SIG NET	GE	GE NET		Avg Abn	S/L	ASA
1671	Tue 01/07/08	849	393	379	44	7	26	5.7%	73%	38	896	766	88	16	26		43.8%	91%	26
1672	Wed 02/07/08	630	458	78	47	9	38	14.7%	94%	12	338	257	65	6	10		19.9%	92%	13
1673	Thu 03/07/08	755	480	197	46	10	22	26.8%	75%	29	259	197	48	10	4		24.9%	83%	21
1674	Fri 04/07/08	969	806	73	49	16	25	18.7%	90%	15	157	89	56	6	6		4.7%	90%	16
1675	Sat 05/07/08	476	408	7	47	14		1.7%	98%	9	148	68	60	9	11		1.3%	96%	11
1676	Sun 06/07/08	608	236	217	118	37		3.6%	91%	14	297	188	35	31	43		5.2%	93%	12
1677	WE	5058	3238	1178	397	113	132	0.0%	0%	0	2565	1950	412	94	109	0	3.5%	30%	5
1678	Mon 07/07/08	1126	742	309	37	22	16	20.5%	77%	24	338	231	79	4	24		12.8%	84%	19
1679	Tue 08/07/08	772	629	65	42	5	31	23.8%	87%	16	341	166	152	9	14		7.2%	88%	15
1680	Wed 09/07/08	791	665	67	32	7	20	22.8%	85%	17	349	160	159	5	25		11.3%	81%	20
1681	Thu 10/07/08	801	584	144	40	9	24	7.4%	84%	21	209	88	101	6	14		46.0%	80%	25
1682	Fri 11/07/08	765	535	176	24	2	28	17.7%	88%	15	392	315	54	14	9		39.2%	93%	12
1683	Sat 12/07/08	417	316	19	70	12		34.6%	90%	15	162	82	44	15	21		3.9%	91%	13
1684	Sun 13/07/08	490	304	21	146	19		35.1%	86%	18	143	44	35	26	38		8.5%	84%	22
1685	WE	5162	3775	801	391	76	119	0.0%	0%	0	1934	1086	624	79	145	0	13.9%	41%	8
1686	Mon 14/07/08	869	654	130	48	10	27	20.1%	77%	28	217	118	78	14	7		27.6%	77%	25
1687	Tue 15/07/08	726	482	159	53	11	21	4.7%	85%	21	270	207	50	8	5		43.0%	89%	19
1688	Wed 16/07/08	812	623	109	38	11	31	40.5%	69%	38	316	172	123	7	14		29.6%	74%	30
1689	Thu 17/07/08	541	364	94	44	9	30	15.9%	90%	17	117	69	31	7	10		5.2%	97%	9
1690	Fri 18/07/08	691	592	46	31	7	15	26.3%	92%	13	365	189	162	7	7		4.8%	92%	14
1691	Sat 19/07/08	258	196	14	44	4		2.9%	99%	10	110	88	2	8	12		4.7%	100%	8
1692	Sun 20/07/08	773	399	205	132	37		11.5%	90%	16	285	203	23	17	42		14.8%	93%	11
1693	WE	4670	3310	757	390	89	124	0.0%	0%	0	1680	1046	469	68	97	0	4.2%	49%	6

The main assumption in the collation of the data is that individuals updating the template did so in an accurate manner.

NOTE: Total number of calls received = Number of calls answered by a human operator.

Use of estimated information

Essential Energy has used estimated information for “Total number of calls received” for the following time periods:

- 31 October 2008 to 9 November 2008
- 28 January 2010 to 31 January 2010; and
- 18 May 2010

Estimates were required on these dates as little to no data was available within the secondary reporting table (SIG Call Data - Excel). Averages based on available data or past weekly contacts were used to estimate the total number of calls received on these dates.

Reliability of information

The reliability of this data is dependent on the accuracy of the data within the SIG Call Data and Symposium as well as the accuracy of the assumptions and estimations that have been made.

Note that this data is not able to be reproduced as historical reporting within Symposium is not available at this level beyond a rolling 12 months. This is illustrated below.

Symposium Reporting Duration Properties:

Historical Duration Properties

Days Of Interval:	31
Days Of Daily:	365
Weeks Of Weekly:	104
Months Of Monthly:	48
Days Of IVR Voice Port Login:	7
Days Of Agent Login and Logout:	8
First Business Day Of the Week:	Monday
Business Hours Per Day:	24
Business Days Per Week:	7
Days Of Call By Call:	7

Historical data is based on assumptions and estimates so caution should be used when using this for benchmarking or decision making purposes.

Worksheet 6.2 - Reliability and Customer Service Performance

6.2.1 – 6.2.2 Unplanned minutes off supply (SAIDI) & Unplanned interruptions to supply (SAIFI) - Actual, target and proposed reliability

Compliance with requirements of the notice

Reliability data has been reported in accordance with the definitions provided in the Reset RIN and AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified in the methodology and assumptions section below.

Source of information

Data was sourced from PowerOn Fusion and an Access database. PowerOn makes up the central modules of Essential Energy's power Distribution Management and Outage Management Systems (DMS/OMS). The spread sheet used to collate data is named: "Working sheet V2".

Data was also sourced from previous RIN's submitted to the AER.

Methodology and Assumptions

The data has been collected and collated in line with the economic RIN Instructions and Definitions guidance issued by the AER. The only exception is that outage data prior to November 2012 did not include de-energised NMIs. This data was not collected at the time. When calculating SAIFI and SAIDI figures these de-energised NMIs would not have been included in the customers affected or contributed to the customer minutes lost but also would not have been included in the total customers. With these missing from both numerator and denominator there would be little effect on the SAIDI and SAIFI figures.

Unmetered accounts are not included in any of the customer numbers and are not included in any SAIDI, SAIFI or MAIFI data.

Use of estimated information

Not applicable as actual information has been used for the period 2008 to 2013. The current year estimates are based on the actual figures as at the end of January and the historical averages for the remaining months. Target figures are based on the internal normalised target figures for 2013/14.

Reliability of information

Historical information is considered reasonably reliable.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

6.2.3 Unplanned momentary interruptions to supply (MAIFI) - Actual, target and proposed reliability

Compliance with requirements of the notice

Reliability data has been reported in accordance with the definitions provided in the Reset RIN and AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified in the methodology and assumptions section below.

Source of information

Data was sourced from PowerOn Fusion and an Access database which contains the maintenance history for reclosers and circuit breakers (CB). PowerOn makes up the central modules of Essential Energy's power Distribution Management and Outage Management Systems (DMS/OMS).

Only one year of data was available – 2012/13 due to the small number of reclosers being connected to SCADA before this.

Methodology and Assumptions

The methodology used in this section was as provided in the economic RIN Instructions and Definitions document issued by the AER.

Recloser and CB operation data was collected from TCS. Only those connected to SCADA were available. These cover 89% of our customers. Only operations that did not eventually result in a lockout were counted.

The data was cleansed of operations that were due to maintenance operations by removing all operations for each recloser / CB that occurred on days where that recloser / CB was undergoing maintenance. This data was sourced from a database maintained by the Zone Substation maintenance team.

Total downstream customers affected by each operation were counted regardless of whether there were downstream sections that had reclosers that were not connected to SCADA. The total customer base used was the total number of customers connected to sections where the recloser or CB was in SCADA.

Unmetered accounts are not included in any of the customer numbers and are not included in any SAIDI, SAIFI or MAIFI data.

Use of estimated information

The data for years 2008 to 2012 was estimated by proportioning 12/13 figures back based on a ratio of normalised total SAIFI for the year in question against normalised total SAIFI for 12/13.

Reliability of information

All information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

6.2.4 Customer numbers

Compliance with requirements of the notice

Reliability data has been reported in accordance with the definitions provided in the Reset RIN and AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified in the methodology and assumptions section below.

Source of information

Historical data was sourced from PowerOn Fusion and an Access database. PowerOn makes up the central modules of Essential Energy's power Distribution Management and Outage Management Systems (DMS/OMS).

The spread sheet used to collate data is named: "Working sheet V2".

Methodology and Assumptions

The data has been collected and collated in line with the economic RIN Instructions and Definitions guidance issued by the AER. Customer numbers prior to November 2012 did not include de-energised NMIs. This data was not collected at the time. The estimated de-energised customer numbers for previous years has been added to the totals and proportioned across the feeder categories.

Unmetered accounts have been added into each year's figures.

The customer numbers as reported in this table are as per the definition in the RIN guidance but are not as per used in calculating SAIDI, SAIFI and MAIFI.

Those customer numbers did not include unmetered accounts and prior to November 2012 did not include de-energised NMI's.

Use of estimated information

Estimated de-energised customers were derived by proportioning the 12/13 de-energised customers based on the total customers in each year to the total in 12/13.

Reliability of information

Historical information is considered reasonably reliable.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

6.2.5 Customer service

Compliance with requirements of the notice

The data has been reported in accordance with the definitions provided by the AER within the RIN unless otherwise specified in the methodology and assumptions section below.

Whilst Essential Energy does have other phone lines, data within this section was from the fault line only.

Source of information

For 2008/09, data was sourced from a secondary reporting table (SIG Call Data – Excel shown below) which has been manually updated with daily data from the main reporting tool, Symposium.

SIG Stats.xlsm - Microsoft Excel

	M	AT	AU	AV	AW	AX	AY	AZ	BE	BG	BP	BQ	BR	BS	BT	BU	BV	CA	CC
1		PORT MACQUARIE									QUEANBEYAN								
2		CUSTOMER							CENTRE		CUSTOMER							CENTRE	
3		ACTUAL	SIG	SIG NET	GE	GE NET	PLND OUT	Avg Abn	S/L	ASA	ACTUAL	SIG	SIG NET	GE	GE NET		Avg Abn	S/L	ASA
1671	Tue 01/07/08	849	393	379	44	7	26	5.7%	73%	38	896	766	88	16	26		43.8%	91%	26
1672	Wed 02/07/08	630	458	78	47	9	38	14.7%	94%	12	338	257	65	6	10		19.9%	92%	13
1673	Thu 03/07/08	755	480	197	46	10	22	26.8%	75%	29	259	197	48	10	4		24.9%	83%	21
1674	Fri 04/07/08	969	806	73	49	16	25	18.7%	90%	15	157	89	56	6	6		4.7%	90%	16
1675	Sat 05/07/08	476	408	7	47	14		1.7%	98%	9	148	68	60	9	11		1.3%	96%	11
1676	Sun 06/07/08	608	236	217	118	37		3.6%	91%	14	297	188	35	31	43		5.2%	93%	12
1677	WE	5058	3238	1178	397	113	132	0.0%	0%	0	2565	1950	412	94	109	0	3.5%	30%	5
1678	Mon 07/07/08	1126	742	309	37	22	16	20.5%	77%	24	338	231	79	4	24		12.8%	84%	19
1679	Tue 08/07/08	772	629	65	42	5	31	23.8%	87%	16	341	166	152	9	14		7.2%	88%	15
1680	Wed 09/07/08	791	665	67	32	7	20	22.8%	85%	17	349	160	159	5	25		11.3%	81%	20
1681	Thu 10/07/08	801	584	144	40	9	24	7.4%	84%	21	209	88	101	6	14		46.0%	80%	25
1682	Fri 11/07/08	765	535	176	24	2	28	17.7%	88%	15	392	315	54	14	9		39.2%	93%	12
1683	Sat 12/07/08	417	316	19	70	12		34.6%	90%	15	162	82	44	15	21		3.9%	91%	13
1684	Sun 13/07/08	490	304	21	146	19		35.1%	86%	18	143	44	35	26	38		8.5%	84%	22
1685	WE	5162	3775	801	391	76	119	0.0%	0%	0	1934	1086	624	79	145	0	13.9%	41%	8
1686	Mon 14/07/08	869	654	130	48	10	27	20.1%	77%	28	217	118	78	14	7		27.6%	77%	25
1687	Tue 15/07/08	726	482	159	53	11	21	4.7%	85%	21	270	207	50	8	5		43.0%	89%	19
1688	Wed 16/07/08	812	623	109	38	11	31	40.5%	69%	38	316	172	123	7	14		29.6%	74%	30
1689	Thu 17/07/08	541	364	94	44	9	30	15.9%	90%	17	117	69	31	7	10		5.2%	97%	9
1690	Fri 18/07/08	691	592	46	31	7	15	26.3%	92%	13	365	189	162	7	7		4.8%	92%	14
1691	Sat 19/07/08	258	196	14	44	4		2.9%	99%	10	110	88	2	8	12		4.7%	100%	8
1692	Sun 20/07/08	773	399	205	132	37		11.5%	90%	16	285	203	23	17	42		14.8%	93%	11
1693	WE	4670	3310	757	390	89	124	0.0%	0%	0	1680	1046	469	68	97	0	4.2%	49%	6

For 2009/10 to 2012/13, data was sourced from previously reported RINs.

Methodology and Assumptions

For 2008/09 data, Essential Energy used daily run historical call report data from a secondary reporting table (SIG Call Data - Excel). The data was manually updated with daily data from the reporting tool, Symposium. The main assumption in the collation of the data is that individuals updating the template did so in an accurate manner.

For 2009/10 to 2012/13, data was sourced from previously reported RINs which have been audited.

Note: A variance in volume will be seen between data table 6.1.1 and 6.2.5 due to the AER's abandoned calls estimate calculation that was applied in previously audited data used in 6.2.5 and the manual updating of the SIG Call Data – Excel used in 6.1.1.

Note: Essential Energy's use of the AER's abandoned calls estimate calculation and the negative result of using said calculation has been documented and reported upon in previous RIN's.

Use of estimated information

Essential Energy has used estimated information for "Total number of calls received" for the period 31 October 2008 to 9 November 2008.

Estimates were required on these dates as little to no data was available within the secondary reporting table (SIG Call Data - Excel). Average based on available historical activity was used.

All forecast data is estimated information. Refer to methodology and assumptions section above.

Reliability of information

As the data for 2009/10 to 2012/13 has previously been audited, the data is considered to be reliable.

All forecast information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Note that this data is not able to be reproduced as historical reporting within Symposium is not available at this level beyond a rolling 12 months. This is illustrated below.

Symposium Reporting Duration Properties:

Historical Duration Properties

Days Of Interval:	31
Days Of Daily:	365
Weeks Of Weekly:	104
Months Of Monthly:	48
Days Of IVR Voice Port Login:	7
Days Of Agent Login and Logout:	8
First Business Day Of the Week:	Monday
Business Hours Per Day:	24
Business Days Per Week:	7
Days Of Call By Call:	7

6.2.6 Estimated data percentage accuracy - SAIDI

Compliance with requirements of the notice

The accuracy levels shown are based on previous audit results combined with the estimation of impacts of known data issues.

Source of information

Data was sourced from previous audit reports.

Methodology and Assumptions

The known data issues including those identified in past audits relate to the fact that Essential Energy's power Distribution Management and Outage Management Systems do not cover switching of the LV network so the system automatically assumes the whole distribution is off when it may just be some customers. Essential Energy rely on the network operators to change these manually. Studies have shown there could be an overestimation of just under 1 minute on SAIDI. There can be issues with communication delays with SCADA giving a slightly incorrect time of restoration. Manually confirmed incidents for mainly single premise outages can have incorrect times due to process issues with Power on Fusion.

Use of estimated information

This has been explained in the methodology and assumptions section above.

Reliability of information

All information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

6.2.7 Estimated data percentage accuracy - SAIFI

Compliance with requirements of the notice

The accuracy levels chosen are based on previous audit results combined with the estimation of impacts of known data issues.

Source of information

Data was sourced from previous audit reports.

Methodology and Assumptions

The known data issues including those identified in past audits relate to the fact that Essential Energy's power Distribution Management and Outage Management Systems do not cover switching of the LV network so the system automatically assumes the whole distribution is off when it may just be some customers. Essential Energy rely on the network operators to change these manually. Studies have shown there could be an overestimation of just under 1 minute on SAIDI with a smaller impact anticipated on SAIFI. There can be issues with communication delays with SCADA giving a slightly incorrect time of restoration. Manually confirmed incidents for mainly single premise outages can have incorrect times due to process issues with Power on Fusion.

Use of estimated information

This has been explained in the methodology and assumptions section above.

Reliability of information

All information is considered to be estimated and caution should also be used when using this for benchmarking or decision making purposes.

Worksheet 6.3 - Sustained Supply

6.3.1 Sustained interruptions to supply (from 1 July 2008)

Compliance with requirements of the notice

Data has been reported in accordance with the definitions provided in the Reset RIN and AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified in the methodology and assumptions section below.

Source of information

Data was sourced from PowerOn Fusion and an Access database. PowerOn makes up the central modules of Essential Energy's power Distribution Management and Outage Management Systems (DMS/OMS). The spread sheet used to collate data is named: "Table 6.3 v5"

The spread sheet name showing the mapping of Essential Energy cause list to the AER RIN cause list is "Cause Mapping".

Methodology and Assumptions

The data has been collected and collated in line with the economic RIN Instructions and Definitions guidance issued by the AER. The only exception is that outage data prior to November 2012 did not include de-energised NMIs. This data was not collected at the time. When calculating SAIFI and SAIDI figures these de-energised NMIs would not have been included in the customers affected or contributed to the customer minutes lost but also would not have been included in the total customers. With these missing from both numerator and denominator there would be little effect on the SAIDI and SAIFI figures.

Sustained interruption has been assumed to be any interruption of 1 minute or greater duration i.e. it does not include momentary interruptions. This is as per the definition of an interruption in the STPIS.

Unmetered accounts are not included in any of the customer numbers and are not included in any SAIDI, SAIFI or MAIFI data.

Use of estimated information

Not applicable as actual information has been used for the period 2008 to 2013.

Reliability of information

Information has been sourced from current systems and is considered reliable.

Worksheet 6.4 - Historical Major Event Days

6.4.1 Major event day data

Compliance with requirements of the notice

Data has been reported in accordance with the definitions provided in the Reset RIN and AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified in the methodology and assumptions section below.

Source of information

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

The spread sheet used to collate data is named: "Working sheet V2"

Methodology and Assumptions

The methodology used in this section was as provided in the economic RIN Instructions and Definitions document issued by the AER.

Data prior to November 2012 did not include de-energised NMIs. This data was not collected at the time. When calculating SAIDI figures these de-energised NMIs would not have been included in the customers affected or contributed to the customer minutes lost but also would not have been included in the total customers. With these missing from both numerator and denominator there would be little effect on the SAIDI figures.

The SAIDI values are calculated after excluding events allowed under clauses 3.3(a) and 5.4 of the STPIS. MED's are not excluded from this data set.

Unmetered accounts are not included in any of the customer numbers and are not included in any SAIDI, SAIFI or MAIFI data.

Use of estimated information

Not applicable as actual information has been used for the period 2003 to 2013.

Reliability of information

Information has been sourced from current systems and is considered reliable.

Worksheet 7.1 - Plans, Policies, Procedures and Strategies

7.1.1 Plans, policies, procedures and strategies

Compliance with requirements of the notice

A basis of preparation has not been prepared for this table as all the information contained within the table is qualitative in nature i.e. brief descriptions of key internal plans, policies, procedures or strategies that are used to plan and conduct day to day operations and that have been relied upon in the development of the regulatory proposal. It also identifies any internal plans, policies, procedures and strategies that have changed in the current regulatory control period or that are expected to change before the next regulatory control period where the change has been identified as a step change.

Worksheet 7.2 - Contingent Projects*

7.2.1 Proposed contingent projects for the 2014-15 to 2018-19 regulatory control period*

Compliance with requirements of the notice

At the time of preparation of this RIN, Essential Energy could not reasonably foresee any proposed Project/s for which the total capital expenditure for the Project met the threshold as referred to in Clause 6.6A.1(b)(2)(iii) of Rule 6.6A of the NER.

However, subject to paragraph (b) of Clause 6.6A.2 of Rule 6.6.A of the NER, Essential Energy may, during the 2014-15 to 2018-19 regulatory period, apply to the AER to amend the distribution determination that applies to Essential Energy where a trigger event for a contingent project in relation to its distribution determination has occurred.

Cell E9 of Table 7.2.1 is actual proposed annual revenue requirement for 2014-15 ($million, nominal), from the Post Tax Revenue Model (PTRM).

Worksheet 7.3 - Obligations, Requirements and Standards

7.3.1 Obligations or requirements

Compliance with requirements of the notice

A basis of preparation has not been prepared for this table as all the information contained within the table is qualitative in nature i.e. those obligations and requirements that have been relied upon in the development of the regulatory proposal.

Worksheet 7.4 - Shared Assets

7.4.1 – 7.4.2 Shared Assets

Compliance with requirements of the notice

The information provided reports the value of each existing access licence contract or Facility Access Agreement (FAA). Only units in total dollar values will be shown, as there are considerable differences in the overall pricing.

Source of information

The data obtained for Shared Assets is obtained from both existing agreements and billing history spread sheets.

Methodology and Assumptions

Existing access agreements have been used for forward reporting, except for NBN Co revenues. At this point it seems impossible to determine the exact forward estimates as both historical and future data have no consistency of growth or use of shared assets.

Historical values are based on actual billing values. Growth has been static for several years, except for NBN Co.

Essential Energy have taken a conservative view to growth for NBN Co based on the possibility that they will use a FttN technology instead of the current FttP which will have a major reduction in use of poles.

Use of estimated information

Essential Energy has used estimated information for shared asset revenue for NBN Co only.

- Historical billing data and future increases are in line with existing access agreements, either 5% or CPI. Where CPI is the agreed escalator Essential Energy have assumed a 2.5% annual year on year value.
- NBN Co growth is unknown and cannot be confirmed by NBN Co as they are still undergoing a strategic review on their design architecture. This will have a major impact on the originally estimated use of Essential Energy's poles, which will relate to minor annual increases to revenues.
- In addition, due to Network NSW taking over renegotiations with NBN Co on a whole of NSW FAA, price per pole will most definitely be diminished for Essential Energy. The impact is unknown at this stage.

Reliability of information

These figures are based on current actuals and increases as per existing agreements. Therefore the data provided for this is considered reasonably reliable.

Worksheet 7.5 - EBSS

7.5.1 The carryover amounts that arise from applying the EBSS during the 2009-10 to 2013-14 regulatory control period

Compliance with requirements of the notice

Information reported in table 7.5.1 is in accordance with the Regulatory Accounting Statements as well as Essential Energy's Cost Allocation Methodology (CAM) and Essential Energy's Post Tax Revenue Revenue (PTRM) model. Essential Energy prepares Standard Control Services Annual Regulatory Statements for AER in compliance with Australian Accounting Standards and the Regulatory Information Requirements Guidelines for the NSW Electricity Distributors. These are independently audited and reviewed each year before reporting separately to the AER. The Regulatory Accounting Statements include Standard Control Services (Distribution) and Standard Control Services (Transmission) and Alternative Control Services (Public Lighting).

The CPI index, rebased index, actual and estimated inflation data and the formula for calculation of EBSS target was pre-provided by AER in their Reset RIN Templates. Essential Energy applied these AER pre-provided figures in its calculations.

Source of information

Data contained in the Opex Allowance table was sourced from the Regulatory Accounting Statements issued to the AER, EBSS information submitted to the AER, Peoplesoft and Cognos and the AER's Final Decision PTRM for Essential Energy.

Data contained in the Actuals table was sourced from information used in the compilation of previous annual RINs.

Methodology and Assumptions

The cells in the table have been linked to the appropriate worksheets in the Substantive Regulatory Proposal.

The actual opex data reported on table 7.5.1 aligns to the Regulatory Accounting Statements and EBSS information submitted to the AER from FY2010-FY2013. The forecast data aligns to original AER real forecast numbers reported in the Post Tax Revenue Revenue (PTRM) model for Essential Energy.

Use of estimated information

The information is quite accurate, consisting of allowances approved by the AER and Essential Energy's historical costs, extracted from the trial balance.

Reliability of information

Data for prior and current regulatory years is considered to be reasonably reliable.

7.5.2 Proposed forecast opex for the EBSS for the forthcoming regulatory control period

Compliance with requirements of the notice

This section contains forecast data on the EBSS calculation for Essential Energy.

Source of information

Data was sourced from calculations prepared for the Substantive Regulatory Proposal for the 2014 AER Determination.

Methodology and Assumptions

The cells in the tables have been linked to the appropriate worksheets in the Substantive Regulatory Proposal.

Use of estimated information

As the data contained in this table is forecast data, it is estimated data.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 7.6 - Indicative Impact on Distribution Charges & Electricity Bills

7.6.1 Indicative impact of the regulatory proposal on the average residential electricity bills*

Compliance with requirements of the notice

The information provided relates to the forecasted impact of the regulatory proposal on the average residential and small business electricity bill.

Source of information

Based on information provided by the AER, email correspondence, and the PTRM model (PTRM SRP V1.xlsm).

Methodology and Assumptions

Distribution costs as a proportion of a typical customer's electricity bill (per cent)

- Source: Essential Energy, Transitional regulatory proposal, p. 5.

Annual bill amount for regulated residential customer

- Source: AER, Energy made easy. IPART, Final report: Review of regulated retail prices for electricity - from 1 July 2013 to 30 June 2016, June 2013, p. 5.
- Note: Based on the annual charge for a typical consumption of 6500KWh per year during the period 1 July 2013 to 30 June 2014. The charges reflect regulated price only. Sample postcode: 2650.

Annual bill amount for regulated business customer

- Source: AER, Energy made easy. IPART, Final report: Review of regulated retail prices for electricity - from 1 July 2013 to 30 June 2016, June 2013, p. 5.
- Note: Based on the annual charge sourced from Energy Made Easy for a typical consumption of 10000KWh per year during the period 1 July 2013 to 30 June 2014. The charges reflect regulated price only. Sample postcode: 2650.

Indicative annual average distribution price impact

- Based on the PTRM model ((PTRM SRP V1.xlsm)

Use of estimated information

All forecast information is estimated.

Reliability of information

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

Worksheet 7.7 - Services & Indicative Prices

7.7.1 Standard control services

Compliance with requirements of the notice

The information provided relates to historical and forecast Standard Control Services pricing, quantities and revenue.

Source of information

Data has been sourced from the following:

- Weighted Average Price Cap (WAPC) model
- Post Tax Revenue Model (PTRM)
- Regulatory Accounts

Methodology and Assumptions

The historical pricing, quantities and revenue was sourced from the audited WAPC model.

- Fee income includes Miscellaneous and Monopoly fees, and Emergency Recoverable Works income.
- Other income varies each year and includes income types such as rental, metering services and zone substation income.
- Mwh's are not associated with Fee income and Other income.

Use of estimated information

All forecast information is estimated.

All WAPC models to 2011-12 have been audited and the Regulatory Accounts have been audited. As such, these figures are considered to be actuals.

Reliability of information

Historical data is considered to be reliable as it comes from audited sources.

All forecast information is considered to be estimated and caution should be used when using this for benchmarking or decision making purposes.

7.7.2 Negotiated Services

Compliance with requirements of the notice

As Essential Energy has no negotiated services, zero values have been inputted into the table in the Reset RIN.