SPI Electricity Pty Ltd

AER Category Analysis Regulatory Information Notice

Regulatory Years 2009 to 2013

Basis of Preparation – Category Analysis data

2009 to 2013 Regulatory Years

1. Overview

This Basis of Preparation document supports the preparation and reporting of the data presented in SPI Electricity Pty Limited's ("SPI Electricity") reports entitled 'DNSP category analysis data - Actual Information', 'DNSP category analysis data - Estimated Information', 'DNSP category analysis data - Consolidated Information' and 'Other Supporting Information' ("the Reports"). The Reports provide data solely for the use of the Australian Energy Regulator ("AER") to perform benchmarking activities under the AER's Better Regulation program.

The ultimate Australian parent of SPI Electricity is SP Australia Networks (Distribution) Ltd which is part of a listed stapled group trading as SP AusNet. SP AusNet comprises the Stapled Group of SP Australia Networks (Distribution) Ltd and its subsidiaries, SP Australia Networks (Transmission) Ltd and its subsidiaries, and SP Australia Networks (Finance) Trust. The Stapled Group is also referred to as the SP AusNet Group.

The Reports have been prepared in accordance with the 'Regulatory Information Notice issued under section Division 4 of Part 3 of the *National Electricity (Victoria) Law'* ("RIN") issued by the AER on 7 March 2014 and other authoritative pronouncements of the AER, except as noted below:

- Template 2.8 Maintenance – access track maintenance expenditure has been reported within Template 2.7 Vegetation Management. This is not considered material expenditure. Refer to disclosures within section 2.8 Maintenance below.

SPI Electricity's regulatory year is the period 1 January to 31 December ("Regulatory Year"). Data included in the Reports has been provided for each Regulatory Year from 2009 through to 2013. All financial data included in the Reports is presented in thousands of Australian dollars, rounded to the nearest thousand dollars. Non-financial data is stated as per the measures specified in the Reports.

The SP AusNet Group owns and operates 3 regulated networks – an electricity distribution network, a gas distribution network, and an electricity transmission network. Employees of the SP AusNet Group work across the 3 regulated networks and there are shared costs and overhead and other corporate costs that cannot be directly allocated to a particular network. These costs are proportioned amongst SP AusNet's 3 regulated networks based on a quarterly Activity Based Costing survey process completed by all cost centre managers and in accordance with SP AusNet's Cost Allocation Methodology.

Materiality has been applied throughout the Reports and Basis of Preparation. Materiality is defined as information that if omitted, misstated or not disclosed has the potential, individually or collectively to influence the economic decisions of users.

The Reports require inputs to be allocated between Standard Control Services and Alternative Control Services.

For the Regulatory Years upon which the AER has made a distribution determination, Standard Control Services are defined as per the National Electricity Rules ("NER"). For clarity, Standard Control Services capture services only available through the network (typically provided to all customers or a broad class of customers) recovered through general network tariffs. For the Regulatory Years where an AER determination was not in effect, Standard Control Services are considered prescribed services and prescribed metering services as determined by the Essential Services Commission of Victoria.

Alternative Control Services are defined in the NER. By way of context, Alternative Control Services are intended to capture electricity distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Where an AER determination was not in effect at the time, Alternative Control Services are excluded electricity distribution services as determined by the Essential Services Commission of Victoria. Alternative control services are electricity distribution services that are a direct control service but not a standard control service.

In conformity with AER requirements, the preparation of the Reports requires the use of certain critical management estimates. For the purpose of preparing the Reports, 'estimated information' is defined as information presented in the Reports whose presentation is not materially dependent on information recorded in accounting records or other records used in the normal course of business, and whose presentation for the purpose of the RIN is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the Reports.

'Actual Information' is defined as information materially dependent on information recorded in historical accounting records or other records used in the normal course of business, and whose presentation is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation.

Where estimated information has been presented, the circumstances and the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is SPI Electricity's best estimate has also been set out below. By definition, estimates seldom equal the related actual results and estimates have only been made for the purpose of disclosing the information requested. Considerations of the cost and efficiency of preparation, as well as the reliability and accuracy of data available, have been taken into account in determining the best methodology to determine the estimates.

To the extent applicable, the information reported has been prepared in a manner consistent with the policies and methodologies applied in preparing the Annual Regulatory Accounts. There were no changes in Accounting Policies in the 2009 to 2013 Regulatory Years which had a material impact on the information presented.

The preparation methodologies and information sources adopted in the preparation of the Reports are set out below. These methodologies and sources have been consistently applied and used for all Regulatory Years, unless otherwise stated.

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2.1 Expenditure Summary

Capital Expenditure ("Capex") reported is the capital costs and capital construction costs of operating the network and relates to standard control services only.

Operating Expenditure ("Opex") reported is the costs of operating and maintaining the network (excluding all Capex) and relates to standard control services only.

Table 2.1.1 - Standard control services capex, Table 2.1.2 - Standard control services opex by category, Table 2.1.3 - Alternative control services capex and Table 2.1.4 - Alternative control services opex

The information reported was prepared using Capex and Opex data extracted from the Financial System. The expenditure reported in Total Capex and Total Opex in Table 2.1.1 to Table 2.1.4 is mutually exclusive and collectively exhaustive.

The expenditure reported for the following categories relate to direct costs only and excludes expenditure on overheads -

- Replacement expenditure;
- Connections;
- Augmentation Expenditure;
- Non-network;
- Vegetation management;
- Emergency Response;
- Metering;
- Public Lighting;
- Fee and Quoted; and
- Maintenance.

Information reported in Tables 2.1.1 to 2.1.4 is estimated information where the corresponding template information is considered estimated information. Total Capex and Opex have been reported on an 'as incurred' basis. All expenditure has been presented in nominal dollars.

The sum of each of the Capex and Opex line items in the Tables in 2.1 Expenditure Summary minus the 'balancing item' line equals the total Capex and Opex in all templates from 2.2 Repex to 2.8 Overheads and Templates 4.1 Public Lighting to 4.4 Quoted Services.

The 'balancing item' line includes expenditure (Capex or Opex) reported more than once within the Templates 2.2 Repex to 2.8 Overheads and 4.1 Public Lighting to 4.4 Quoted Services, expenditure and capitalised overheads included in the Annual Regulatory Accounts which doesn't meet the definitions of data requested in the Category Analysis templates, capital contributions not included within the templates and overheads which are capitalised directly to Capex projects. The 'balancing items' are considered estimated information due to the estimated financial information included in calculating the templates which are being reconciled.

Amounts reported as capital contributions (“capcons”) were extracted from the Annual Regulatory Accounts for all Regulatory Years.

Values reported in Tables 2.1.2 to 2.1.4 in the summary sheet reconcile to the Annual Regulatory Accounts at the total Capex and Opex level. In relation to Table 2.1.1, capcons are required to be removed from the total Capex line in order to reconcile to the Annual Regulatory Accounts.

Table 2.1.5 - Dual function assets capex and Table 2.1.6 - Dual function assets opex by category

This table has been completed as zero as there are no dual function assets owned by SPI Electricity.

2.2 Repex

Replacement Expenditure ("Repex") is the non-demand driven Capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life. Capex has a primary driver of replacement expenditure if the factor determining the expenditure is the existing asset's inability to efficiently maintain its service performance requirement.

For each standardised asset category, 5 years of historical replacement volumes and cost data has been provided for the prescribed asset categories for assets currently in commission. The corresponding age profile of these assets has been provided in Template 5.2 Asset Profile.

The following definitions have been applied in the preparation of the data:

Poles	These are vertically oriented assets that provide load bearing structural support for overhead conductors or other lines assets. This also includes associated pole top structures, such as cross-arms and insulators where these are replaced in conjunction with a pole replacement project It excludes other pole mounted assets that are included in any other asset group, notably pole mounted substations and pole mounted switchgear such as links, fuses, air break switches etc.
Pole top structures	These are horizontally oriented structures and their components that provide support for overhead conductors and related assets to be supported on a pole and provide adequate clearances. This relates to expenditure incurred when a pole top structure is replaced independently of the pole it is located on. This includes cross-arms and insulators. It excludes any pole mounted assets that are included in any other asset group, notably pole mounted substations and pole mounted switchgear such as links, fuses, air break switches etc.
Overhead conductors	These assets have the primary function of distributing power, above ground, within the distribution network. It excludes any pole mounted assets that are included in any other asset group.
Underground cables	These assets have the primary function of distributing power, below ground, within the distribution network. This includes cable ends, joints, terminations and associated hardware and equipment (e.g. surge diverters, etc.), cable tunnels, ducts, pipes, pits and pillars. It excludes any pole mounted assets that are included in any other asset group.
Service lines	Includes assets that provide a physical link and associated assets between the distribution network and a customer's premises.

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 group. This does not include instrument transformers as defined in the National Electricity Rules. It also does not include auxiliary transformers
Switchgear	These are assets used to control, protect and isolate segments of the network This includes disconnect switches, fuses, circuit breakers, links, reclosers, sectionalisers, ring main units, oil insulated fuses etc.
SCADA and Network Control and Protection systems replacement	Replacement expenditure associated with SCADA and network control hardware, software and associated IT systems. Includes replacement of protection and control systems and communication systems. This excludes all costs associated with SCADA and Network Control Expenditure that exist within gateway devices (routers, bridges etc.) at corporate offices. Protection systems has the meaning prescribed in the National Electricity Rules.

Table 2.2.1 – Replacement Expenditure, Volumes and Asset Failures by Asset Category

Replacement expenditure and volumes have been provided for the prescribed standardised asset categories. Where required, additional rows have been added to Table 2.2.1 to ensure all assets are captured.

<u>Preparation Methodology:</u>

Asset Replacements (Quantity)

Asset replacement quantities have been derived from the asset age profiles extracted from the Maximo, Q4 and SDME Asset Management Systems. Asset descriptions in the asset management systems have been aligned as closely as possible with the AER categories to produce age profiles.

The Asset Management Systems provide information in relation to total quantities installed. Installations due to Replacement works cannot be distinguished from installations due to Augmentation works. Based on this, the ratio of Repex to the total of Repex and Augex, on a year by year basis, has been applied to the total quantity of assets installed in each year to provide an estimate of the quantity of asset replacements.

Due to the material increase in replacement volumes of Service Lines resulting from the recent commencement of the Service Lines Replacement Program, quantity data for the 2011 to 2013 Regulatory Years has been extracted from the volumes reported in the Annual Regulatory Accounts.

Replacement Expenditure

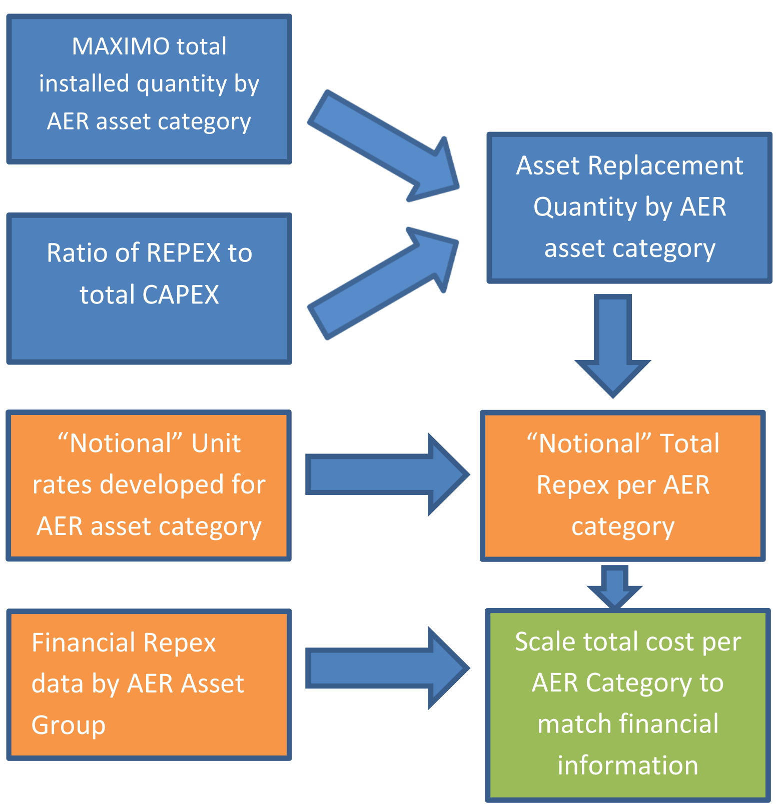
Capex and associated non-financial information has been reported against the Regulatory Year on an 'as incurred' basis. Expenditure reported relates to costs directly attributable to replacement of the asset and excludes expenditures on overheads. All Capex has been presented in nominal dollars.

The sum of the asset group replacement expenditures is equal to the total replacement expenditure in Template 2.1 Expenditure Summary.

Financial information was sourced from the Financial Information System. A report was generated for the relevant Regulatory Years based on the designated replacement expenditure work codes.

The financial data for asset replacements is captured at an aggregated level similar to the Asset Group in Table 2.2.1 (i.e. financial data is not captured at the Asset Category level). Engineering expertise was used to align the expenditure by work code to the prescribed Asset Groups. A methodology to apportion the Asset Group expenditure across the AER Asset Categories was developed as illustrated in Figure 1 below.

Figure 1: Overview of estimation process for Asset Replacements (Quantity) and Asset Expenditure ($)



A representative unit cost for each asset category has been multiplied by the estimated quantity of assets replaced, to give a notional total expenditure for each Asset Category. The notional total expenditure for the Asset Categories in each Asset Group was compared to the actual expenditure for the Asset Group (from financial data) and then scaled by a factor in order to apportion the total actual expenditure across the numerous Asset Categories.

In relation to the SCADA and 'Other DNSP Asset' Groups, the total pool of costs was allocated into Asset Categories based on volume data. For these Asset Groups, a uniform unit rate was assumed as additional information was not available.

Estimated Information:

All Asset Replacement Quantity and Replacement Expenditure data provided are considered estimated information due to the judgments made to align the SPI Electricity asset categories with the categories required by AER.

SPI Electricity does not maintain unit rates that correlate with the AER Asset Categories. A single rate for replacement of an asset does not exist within the business as there are variables that impact the replacement cost including:

- whether the work is insourced or outsourced;
- whether the replacement is done in normal time or overtime;
- whether the work is done live line or during an outage; and
- the distance of the asset from the depot.

In order to apply the methodology described above 'Notional' unit rates were developed using material cost from recent procurement data added to contract costs for labour and equipment from a current Service Provider contract.

The 'Notional' unit rates developed should not be considered representative of unit rates across the business as the contract was negotiated to include an efficient package of work with regard to volume, geographic area, density of network etc. and the conditions of this work package do not represent the balance of the network.

Additionally, a uniform unit rate has been assumed for the categories SCADA and 'Other DNSP Assets' due to limitations in the information available.

Data provided in relation to Asset Replacements and Replacement Expenditure is considered Management's best estimate of the information required based on the data available.

Asset Failures (Quantity)

Preparation Methodology:

Asset Failure is the failure of an asset to perform its intended function safely and in compliance with jurisdictional regulations, not as a result of external impacts such as:

- extreme or atypical weather events; or
- third party interference, such as traffic accidents and vandalism; or
- wildlife interference, but only where the wildlife interference directly, clearly and unambiguously influenced asset performance; or
- vegetation interference, but only where the vegetation interference directly, clearly and unambiguously influenced asset performance.

Asset Failures excludes planned interruptions.

The Asset Failure data provided in Table 2.2.1 has been based on a list of work orders ("WO") extracted from the Q4 and Maximo Asset Management Systems.

Work orders are created in the Asset Management System when action is required to be performed on an asset including routine inspections, maintenance activities, emergency work, unplanned work and corrective action. Each WO is connected to a specific asset in either Q4 or Maximo and WO profiles are based on the WO created date.

Q4 and Maximo allow for a range of codes to be applied to each WO to identify the activities being conducted. The codes do not correlate exactly with the Asset Failure definition provided by AER, however the data has been filtered based on a selection of WO codes that most closely align with the AER definition to derive an estimate of the required Asset Failure data.

WOs have been excluded when associated with animals or vegetation (as per the AER definitions) however, it should be noted that these categories are often used when a failure category is unknown. This will likely lead to a reduction in WOs which should otherwise be included in the failure profiles.

The data provided is based on WO's directly associated with an asset. These WO's indicate that there has been a need for maintenance work, but do not indicate whether the asset (or part of the asset) has been replaced or whether some other activity has addressed the issue.

In some cases (e.g. lines assets where the WO may be associated with a span of conductor), the actual maintenance work may have been required on components associated with that span which may not necessarily be the conductor itself however, based on the data available activities have been classified into the closest AER category.

Estimated Information:

Based on the above, the information provided in relation to Asset Failure quantities is considered estimated information. Data provided is considered the best estimate of the information required based on the data available.

Table 2.2.2 – Selected Asset Characteristics

'Asset Volumes Currently in Commission' and 'Replacement Volumes' of certain asset groups have been provided by the specified aggregated metrics.

Network Type metric (CBD, Urban, Rural Long, Rural Short)

Preparation Methodology:

SPI Electricity does not capture quantities of replacement of assets in Network Type (CBD, Urban, Rural Long, Rural Short) categories. Based on this, the data provided in this table has been estimated.

The total quantity information included in Table 2.2.1 has been reallocated into Network Type metrics on a percentage allocation basis. The percentage splits were obtained from the customer number allocations (by Network Type) included in the AER Economic Benchmarking data submission. The customer number allocations were derived from data extracted from the Service Order Management System where the percentage of customers by feeder location was obtained for each Regulatory Year.

'Conductor Length by Material Type' is based on the total quantity of conductor (per Template 5.2 Asset Age Profile) and from material type data extracted from 'Asset Management Strategy 20-52 Bare conductor Asset Health Report'. This report provides a breakdown of the high voltage ("HV") and low voltage ("LV") conductor in service by material type. To derive asset replacements by year and by material type, the ratio of quantity for each material type has been applied to the total replacement quantity for conductor.

The total Transformer MVA information is based on an extract from the Maximo Asset Management System of all transformers in the network including the kVA rating for each transformer. This extract was used to calculate the total MVA of transformers currently in service which was required to populate the AER Economic Benchmarking Report. The total MVA currently in commission has been extracted from this Maximo data and is equal to that reported for DPA0501 in the AER Economic Benchmarking Report (for all Regulatory Years).

MVA for replaced distribution transformers has been based on the average rating of transformers in the distribution network. This was calculated by dividing the total MVA for assets currently in commission by the total quantity of transformers (all categories) based on information in Template 5.2 Asset Age Profile. The average rating has been multiplied by the total quantity of transformers replaced in each year to give an estimate of the total MVA of replacement transformers.

MVA Disposed has been estimated as equal to the MVA installed in each year. This assumes that replacement assets have a rating equal to the new assets installed during the period. This assumption is required as more specific information is not available.

<u>Estimated Information:</u>

Information reported is considered estimated information based on the percentage allocation methodologies described above and assumptions applied in deriving MVA Disposed. Data provided is considered Management's best estimate of the information required based on the available data.

2.3 Augex

Projects relating to the augmentation of SPI Electricity's network have been included in Template 2.3 Augex. Augmentation has the meaning prescribed in the National Electricity Rules, and also includes work relating to improving the quality of the network, for example, to meet regulatory obligations. Augmentation expenditure does not include gifted assets.

Data Preparation Methodology

Information was sourced from project reports generated in the Fixed Asset Register using augmentation work codes. The reports were run for the 2009 to 2013 Regulatory Years and provided a listing of augmentation works by project and asset. Material projects were reviewed to ensure they met the prescribed augmentation works definition.

Within the reports generated, asset in service is assigned a standardised 'profile' and 'segment' code which identifies the asset type. The SPI Electricity Fixed Asset Capitalisation policy (FIN 25-51) was used to translate the 'profile' and 'segment' codes into asset categories.

Engineering expertise was used to aggregate the asset categories in the Fixed Asset Register into the assets groups as required by Tables 2.3.1, 2.3.2 and 2.3.3. This allocation is considered estimated information as the Fixed Asset Register categories could not be directly assigned to the prescribed AER categories. The category allocations were performed by Engineering experts based on project knowledge and the AER definitions. Due to the estimates and assumptions applied, data included in Tables 2.3.1, 2.3.2 and 2.3.3 is considered estimated information. The data provided is considered Management's best estimate based on the information available.

The report data (in asset groups) was then analysed and grouped at a project level in accordance with the AER requirements. Where projects encompassed more than one segment of the network, they were segregated (for example, where a project included augmentation works on a sub-transmission line and a zone substation, the project has been split between Tables 2.3.1 and 2.3.2).

Table 2.3.1— Augex asset data – Substations

Table 2.3.1 includes augmentation works on any substation in SPI Electricity's network. Each row represents data for an augmentation project for an individual substation.

Preparation Methodology - Non-Financial Information:

Information in relation to Substation Type, Project Type and Project trigger was determined by Engineering planning advice (supported by the Augex submission for the EDPR). Project triggers selected relate to the primary project trigger. Project Types have been selected from the prescribed drop downs in Table 2.3.1.

'BFD-PHM optic fibre' is a communications project ('Other - specify' Project Type). 'Voltage' and 'MVA added' parameters have been deemed 'not applicable' based on the nature of this project.

'Voltage', 'Substation Ratings' and 'MVA/MVAR Added' was obtained from the internal policy document AMS 20-101 'Zone-Substation Transformer Cyclic Rating'. The 'Rating' or 'MVA added' refers to the equipment's normal cyclic rating (for substations). For substation ratings, 'Pre' refers to the relevant characteristic prior to the augmentation work and 'Post' refers to the relevant characteristic after the augmentation work. Where a metric does not undergo any change, or where the project relates to the establishment of a new substation, only the 'Post' column has been completed.

'Units Added' and 'Years Incurred' was obtained from the Fixed Asset Register reports. For material projects, 'Units Added' were reviewed for reasonableness and any required adjustments were made.

Preparation Methodology - Financial information:

Only direct costs for Augex projects have been reported (excluding overheads). Related party and non-related party contracts expenditures have been included in the respective table columns.

- Projects on a subtransmission, substation, switching station and zone substation have been separately included in this table where the total cumulative spend over the life of the project is greater than or equal to $5 million (in nominal dollars) and where project close occurred during the 2009 to 2013 Regulatory Years.

- Projects on a subtransmission, substation, switching station and zone substation with a total cumulative spend of less than $5 million (in nominal dollars) and where project close occurred during the 2009 to 2013 Regulatory Years have been grouped and shown as 'non-material projects'.

Costs and project information for subtransmission, substation, switching station and zone substation augmentation works where 'project close' occurs after 31 December 2013 but expenditure has been incurred prior to 31 December 2013 have not been recorded.

Expenditure has been reported in 'real' (2012/13) terms. This was derived by applying CPI rates obtained from the Australian Bureau of Statistics to the project costs reported, based on the years in which costs accumulated on the relevant projects.

A percentage allocation approach was used to allocate project expenditure (on a 'project close' basis) into the years in which costs were incurred. The percentages applied were derived using a report generated from the Financial System showing the years in which the relevant projects incurred costs. For projects which incurred costs before the 2009 Regulatory Year (but were completed in the 2009 to 2013 Regulatory Years), it has been assumed that all earlier costs were incurred in 2008. This assumption was required as the equivalent report (for years earlier than 2008) is unable to be generated in the current Financial System. The calculation performed is considered the best estimate of the data required, based on the information available. This process was followed for all individual projects reported. The calculation was performed at the project level and project costs in real terms were allocated into the prescribed asset categories based on the percentage split into the same asset categories in nominal terms.

For the 'non-material' projects, the allocation of the total 'project close' expenditure into the years incurred was estimated based on the average yearly project cost allocation of all material projects. This estimate was required as the 'project close' information was not able to be split into the years incurred. CPI rates were applied to the estimated allocation of yearly costs to derive an estimate of the 'non-material' costs in real terms.

In accordance with the AER guidance, 'project close' costs are required to be presented based on direct costs only. This information was required to be estimated due to limitations in relation to 'project close' Financial System reports. A calculation was performed based on a sample of projects (the 3 largest projects) to determine the proportion of direct costs to total costs (per the 'as incurred' Financial System report capturing life to date project costs). The average percentage of the 3 projects sampled was applied to the total expenditure (on a 'project close' basis) for each reported project to derive an estimate of the direct costs only. This calculation assumes that the percentage of direct costs for all projects is consistent with the percentage in the projects sampled.

Under 'Total Expenditure' for transformers, switchgear, capacitors and 'other plant items', only the procurement cost of the equipment has been included, not the installation costs. 'Other plant items' is defined as all equipment involved in utilising or transmitting electrical energy that are not transformers, switchgear or capacitors.

Expenditure under 'Land and easements' is mutually exclusive from expenditure in the 'Total direct expenditure column'.

Estimated Information:

Based on the information outlined above, all financial data provided is estimated information. This data is considered Management's best estimate based on the information available.

Table 2.3.2 — Augex asset data Sub-transmission Lines

Augmentation works on sub-transmission lines includes any lines or cables notionally operating at subtransmission voltages.

Preparation Methodology - Non-Financial Information:

Information in relation to Project Type and Project trigger was determined by Engineering planning advice (supported by the Augex submission for the 2010 EDPR). Project triggers selected relate to the primary project trigger. Project Types have been selected from the prescribed drop downs.

'BFD-PHM optic fibre' is a communications project ('Other - specify' Project Type). The 'Route Line Length Added' parameter has been completed as 'zero' and 'Voltage (Kv)' completed as 'Other – specify' based on the nature of this project.

'SCADA Comms to ZSS (Fibre)' is a communications project ('Other - specify' Project Type). The 'Route Line Length Added' parameter has been completed as 'zero' and 'Voltage (Kv)' completed as 'Other – specify' based on the nature of this project.

Voltage and Route Line Length was obtained from the internal policy document AMS 20-24 'Subtransmission Line and Station Data for Planning Purposes'.

'Poles/Towers Added', 'Poles/Towers Upgraded', 'Circuit kms Added' and Circuit kms Upgraded' and 'Years incurred' was obtained from the Fixed Asset Register reports.

Preparation Methodology - Financial information:

- Projects on sub-transmission lines have been separately included in this table where the total cumulative spend over the life of the project is greater than or equal to $5 million (in nominal dollars) and where project close occurred during the 2009 to 2013 Regulatory Years.

- Projects on sub-transmission lines with a total cumulative spend of less than $5 million (in nominal dollars) and where project close occurred during the 2009 to 2013 Regulatory Years have been grouped and shown as 'non-material projects'.

Costs and project information for sub-transmission line augmentation works where project close occurs after 31 December 2013 but expenditure has been incurred prior to 31 December 2013 have not been recorded.

Expenditure has been recorded in 'real' (2012/13) terms. This was derived by applying CPI rates obtained from the Australian Bureau of Statistics to the project costs reported, based on the years in which costs accumulated on the relevant projects.

A percentage allocation approach was used to allocate project expenditure (on a 'project close' basis) into the years incurred. The percentages applied were derived using a report generated from the Financial System showing the years in which the relevant projects incurred costs. For projects which incurred costs before the 2009 Regulatory Year (but were completed in the 2009 to 2013 Regulatory Years), it has been assumed that all earlier costs were incurred in 2008. This assumption was required as the equivalent report (for years earlier than 2008) is unable to be generated in the current Financial System. The calculation performed is considered the best estimate of the data required, based on the information available. This process was followed for all individual projects reported. The calculation was performed at the project level and project costs in real terms were allocated into the prescribed asset categories based on the percentage split into the same asset categories in nominal terms.

For the 'non-material' projects, the allocation of the total 'project close' expenditure into the years incurred was estimated based on the average yearly project cost allocation of all material projects. This estimate was required as the 'project close' information was not able to be split into the years incurred. CPI rate were applied to the estimated allocation of yearly costs to derive an estimate of the 'non-material' costs in real terms.

In accordance with the AER guidance, 'project close' costs are required to be presented based on direct costs only. This information was required to be estimated due to limitations in relation to 'project close' Financial System reports. A calculation was performed based on a sample of projects (the 3 largest projects) to determine the proportion of direct costs to total costs (per the 'as incurred' Financial System report capturing life to date project costs). The average percentage of the 3 projects sampled was applied to the total expenditure (on a 'project close' basis) for each reported project to derive an estimate of the direct costs only. This calculation assumes that the percentage of direct costs for all projects is consistent with the percentage in the projects sampled.

Installation costs for Plant and Equipment expenditure was required to be separately reported. SPI Electricity does not separately capture the installation costs of projects; as such this information was required to be estimated. A calculation was performed based on a sample of projects (the 3 largest projects) to determine the proportion of installation costs to total expenditures. For the projects sampled, the installation costs were assumed to be equal to the contract cost of these projects. The average percentage of the 3 projects was applied to the Plant and Equipment expenditure for each reported project to derive an estimate of the installation costs. This calculation assumes that the percentage of installations costs for all projects is consistent with the percentage in the projects sampled. Installation volumes have been reported as zero as the installation costs reflect external contract costs and information relating to the associated contractor hours is not available.

'Total Expenditure' for poles/towers, includes the procurement costs of the equipment and civil works but not installation costs. 'Total Expenditure' for civil works, does not include civil works expenditure relating to poles/towers. 'Total Expenditure' for lines, cables and 'other plant item' includes procurement costs but not installation costs. 'Other plant items' is defined as all equipment involved in utilizing or transmitting electrical energy that are not poles/towers (including pole top or tower structures), lines or cables.

Expenditure under 'Land and easements' is mutually exclusive from expenditure in the 'Total direct expenditure column'.

Estimated Information:
Based on the information outlined above, all financial data provided is estimated information. This data is considered Management's best estimate based on the information available.

Table 2.3.3— Augex data - HV/LV Feeders and Distribution Substations

Table 2.3.3 contains information prepared on a 'project complete' basis. This has been used as a proxy for 'as incurred' project data. This assumption has been applied as the information required is not available on an 'as incurred' basis. The Asset Management Systems do not record 'Units Added' or 'Units Upgraded' figures until a project is complete. Similarly, financial information is not attributed to a specific asset until a project is complete.

Based on the above, all Descriptor Metrics and Cost Metrics reported in Table 2.3.3 are considered estimated information. The data provided is considered Management's best estimate, based on the information available.

2.3.3.1 Descriptor Metrics

'Units Added' and 'Units Upgraded' were obtained directly from Fixed Asset Register reports.

Non-financial measures are included in the column according to the final Regulatory Year in which the augmentation assets on projects were commissioned.

2.3.3.2 Cost Metrics

Expenditure has been recorded on a 'project close' basis in nominal dollars.

In accordance with the AER guidance, 'project close' costs are required to be presented based on direct costs only. This information was required to be estimated due to limitations in relation to 'project close' Financial System reports. A calculation was performed based on a sample of projects (the 3 largest projects) to determine the proportion of direct costs to total costs (per the 'as incurred' Financial System report capturing life to date project costs). The average percentage of the 3 projects sampled was applied to the total expenditure (on a 'project close' basis) for each reported project to derive an estimate of the direct costs only. This calculation assumes that the percentage of direct costs for all projects is consistent with the percentage in the projects sampled.

'HV Feeder Augmentations – Overhead Lines' and 'HV Feeder Augmentations – Underground Cables'

- Financial information was sourced from Fixed Asset Register reports and was prepared in accordance with the 'Data Preparation Methodology' outlined above.
- Data reported in these categories is the summation of all augmentation projects on HV feeders undertaken during the 2009 to 2013 Regulatory Years where the total cumulative project expenditure (over the life of the project) was greater than or equal to $0.5 million.

HV Feeder Non-Material Projects

- Financial information was sourced from Fixed Asset Register reports and was prepared in accordance with the 'Data Preparation Methodology' outlined above.
- Data reported in this category is the summation of all augmentation projects on HV feeders undertaken during the 2009 to 2013 Regulatory Years where the total cumulative project expenditure (over the life of the project) was less than $0.5 million.

LV Feeder Augmentations – Overhead Lines & LV Feeder Augmentations – Underground Cables

- Financial information was sourced from Fixed Asset Register reports and was prepared in accordance with the 'Data Preparation Methodology' outlined above.
- Data reported in these categories is the summation of all augmentation projects on LV feeders undertaken during the 2009 to 2013 Regulatory Years where the total cumulative project expenditure (over the life of the project) was greater than or equal to $50,000.

LV Feeder Non-Material Projects

- Financial information was sourced from Fixed Asset Register reports and was prepared in accordance with the 'Data Preparation Methodology' outlined above.
- Data reported in this category is the summation of all augmentation projects on LV feeders undertaken during the 2009 to 2013 Regulatory Years where the total cumulative project expenditure (over the life of the project) was less than $50,000.

Distribution Substation Augmentations – Pole Mounted, Ground Mounted and Indoor

The information reported is the summation of all augmentation projects on Distribution Substations (under the 3 specified types) undertaken during the 2009 to 2013 Regulatory Years.

Financial data was sourced from Fixed Asset Register reports for the Augmentation work codes. Data was obtained at a total distribution substation level. Using information from the GIS System, the annual increase in units in Pole Mounted, Ground Mounted and Indoor Distribution Substations was calculated. The unit data was used to allocate the total distribution substation costs into the required categories using a percentage allocation basis. The data provided is considered an estimate due to the allocation approach discussed above. This was required as expenditure into the prescribed categories is not available.

Estimated Information:

Based on the information outlined above, all financial data provided estimated information. This data is considered Management's best estimate based on the information available.

Table 2.3.4 – Augex Data – Total Expenditure

Preparation Methodology:

Total augmentation expenditure has been recorded for each prescribed asset category.

Using the Fixed Asset Register report (used to prepare Tables 2.3.1 to 2.3.4) which is based on a financial year basis, the percentage of total Augex costs allocated into the 'Augmentation Capex' categories was calculated on a 'project close' basis.

An 'as incurred' project report was generated from the Financial System using the augmentation project work codes. This report provided direct costs only. The calculated Augmentation Capex percentages were applied to the 'as incurred' report to derive an estimate of Total Augex Expenditure on an 'as incurred' basis in the required categories.

Table 2.3.4 does not reconcile to the total of Tables 2.3.1 to 2.3.3 as the data is prepared on an 'as incurred' basis (whereas Tables 2.3.1 to 2.3.3 are prepared on a 'project close' basis) and an estimation has been performed to derive direct costs only. Additionally, there are differences in the data as Templates 2.3.1 and 2.3.2 are presented in real terms. This is consistent with the requirements of the RIN.

Estimated Information:

Information reported in Table 2.3.4 is considered estimated information due to the calculations performed to derive the 'as incurred' Augex category allocations. These calculations were performed based on percentages of 'project close' augmentation data which are also considered estimated information.

This data is required to be estimated as system reports generated on an 'as incurred' basis do not provide sufficient augmentation works identifiers to classify the costs into the required categories.

Data provided is considered Management's best estimate based on the information available.

2.5 Connections

Connections expenditure, connection rating and connection voltage have been reported for all distribution substations installed for complex connection projects. Data provided relates to non-contestable, regulated connection services (as defined in the National Electricity Rules) and includes work performed by third parties on behalf of SPI Electricity. It excludes negotiated connection services and contestable works (including gifted assets in contestable works; gifted assets are not distinguishable in business systems).

All Expenditure has been presented in nominal dollars and has not been distinguished between standard and alternative control services. Expenditure data has been reported as a gross amount (by not subtracting customer contributions from expenditure data).

Data reported in Template 2.5 Connections is distinct from data reported in Template 2.3 Augex.

SPI Electricity records all customer connection costs (including augmentation costs where these are required and paid for by a customer) against specific cost codes (distinct from augmentation works cost codes). In many instances these cost codes do not align with the AER Connection definitions. At the highest level, allocations were undertaken according the following mapping.

SPI Electricity Code	AER Connection Subcategory
104 MEDIUM DENSITY HOUSING	Subdivision
107 U/GROUND SERVICE INSTALLATION	Residential
108 BUSINESS SUPPLY PROJECTS	Commercial/Industrial
109 PRIVATE ELECTRIC LINE REPLACEMENT	Residential Commercial Industrial
110 LOW DENSITY HOUSING	Residential Subdivision
118 COGENERATION PROJECTS	Embedded Generation
Alternative Control Connections	Residential Commercial/ Industrial

Work code 109 contains Connections expenditure relating to the undergrounding of a private line. It includes only the component from the distribution system to the property boundary. The customer is responsible for the entire cost of the undergrounding on their property.

While cost code 110 contained mostly single lot developments (including where an existing single lot is being subdivided) some small number of multi-lot developments are included. Therefore, cost code 110 was allocated using an extract from the connection project estimation database that provided a count and direct cost of single and multi-lot developments for each year. From this extract, an estimated percentage split was generated for both costs (applied to cost data) and volumes (applied to volume data). Splits were sense checked by subject matter experts.

Small scale solar connections are not included in embedded generation.

Alternative control service connections and cost code 109 were allocated using the ratio of residential to commercial gross connections for each year. This ratio was obtained from an extract of the PowerOn system and the percentage split was applied to both costs and volumes.

2.5.1 Descriptor Metrics

Preparation Methodology:

Underground/Overhead splits have been calculated as follows:

SPI Electricity Code	AER Connection Subcategory
104 MEDIUM DENSITY HOUSING	Split performed with Overhead/Underground lines asset count in Fixed Asset Register (averaged over 2009-13)
107 U/GROUND SERVICE INSTALLATION	All underground
108 BUSINESS SUPPLY PROJECTS	Split performed with Overhead/Underground lines asset count in Fixed Asset Register (averaged over 2009-13)
109 PRIVATE ELECTRIC LINE REPLACEMENT	All underground
110 LOW DENSITY HOUSING	Split performed with Overhead/Underground lines asset count in Fixed Asset Register (averaged over 2009-13)
118 COGENERATION PROJECTS	Fixed Asset Register project specific analysis
Alternative control connections	Split performed with actual data captured in tariff codes in the billing system

'MVA added' for distribution substations has been estimated for connection services by multiplying the number of substations in each cost code by an assumed standard for the class of customers in the cost code supplied by distribution planning subject matter experts (1MVA for business supply projects, 0.5MVA for medium density housing and 0.2MVA for low density housing).

The number and cost of substations for each SPI Electricity cost code has been estimated from an extract of the Fixed Asset Register. No other SP AusNet system contains asset data that can be identified as Customer Connection Capex.

For HV and LV augmentation metrics, 'kms added' refers to the net addition of circuit line length resulting from the augmentation work of complex connections. Costs and circuit length was estimated from an extract of the Fixed Asset Register. No other SP AusNet system contains asset data that can be identified as Customer Connection Capex.

Mean days to connect data was estimated from extracts from the Customer Information System (for the 2011 to 2013 Regulatory Years) and the historic outage management system (for the 2009 and 2010 Regulatory Years).

'Volume of GSL Breaches', 'GSL Payments' and 'Volume of Customer Complaints relating to Connection Services' was taken directly from the audited Non-financial Annual AER RIN templates (2011 to 2013) or Victorian Comparative Performance Report templates (2009 to 2010).

Cost per lot is estimated by dividing the costs from Table 2.5.2 by the number of lots generated from an extract of the the connection project estimation database system.

Estimated Information:

All information in Table 2.5.1 is considered an estimate except for previously audited GSL and customer complaint data. In particular, cost data included in Table 2.5.1 is on an 'as commissioned' basis as it is sourced from the Fixed Asset Register. This will only be indicative of the incurred costs.

Additionally, information sourced from the Fixed Asset Register is on a financial year basis (ending 31 March), not a calendar year basis. This data is considered to provide a reasonable estimate of the information required on a calendar year basis.

The information provided is considered Management's best estimate of the information required based on the data available.

2.5.2 Cost Metrics by Connection Classification

Connections expenditure is the costs to establish new connection assets and upgrades to existing connections assets necessary to meet customer connection requests. This excludes alterations to existing connection assets.

Preparation Methodology:

Total direct costs, including the customer contribution, by cost code have been taken from information supporting the audited Annual Regulatory Accounts. Alternative control connection costs have also been taken from Template 4.3 Fee-based Services.

Total connection volumes were estimated using extracts from the Connection Project Estimation database and alternative control connection volumes from information supporting the audited Annual Regulatory Accounts.

SPI Electricity does not capture costs or volumes in the Simple/Complex categories required. Therefore, an extract from the Fixed Asset Register has been used to estimate the cost (by direct cost) and volume (by number of projects) splits required. The percentage splits estimated have been applied to the 'as incurred' costs extracted from the Annual Regulatory Accounts and the project volumes (projects closed) from the Connection Project Estimation database. The financial asset register filters used for the allocation are set out in the table below.

SPI Electricity Code	Asset Register filter	AER Connection Classification
		RESIDENTIAL
Alternative Control Residential Connections 107 U/GROUND SERVICE INSTALLATION 109 PRIVATE ELECTRIC LINE REPLACEMENT	* n/a (see section 2.5)	SIMPLE CONNECTIONS
107 U/GROUND SERVICE INSTALLATION 109 PRIVATE ELECTRIC LINE REPLACEMENT 110 LOW DENSITY HOUSING	* Projects with just LV costs	COMPLEX CONNECTION LV
110 LOW DENSITY HOUSING	Projects with HV costs (projects may or may not also contain LV costs)	COMPLEX CONNECTION HV (NO UPSTREAM ASSET WORKS)
		COMMERCIAL/INDUSTRIAL
Alternative Control Commercial Connections 109 PRIVATE ELECTRIC LINE REPLACEMENT	* n/a (see section 2.5)	SIMPLE CONNECTIONS
109 PRIVATE ELECTRIC LINE REPLACEMENT 108 BUSINESS SUPPLY PROJECTS	* Projects with just LV costs	COMPLEX CONNECTION HV (CUSTOMER CONNECTED AT LV, MINOR HV WORKS) ($000'S)
108 BUSINESS SUPPLY PROJECTS	Projects with HV and LV costs	COMPLEX CONNECTION HV (CUSTOMER CONNECTED AT LV, UPSTREAM ASSET WORKS) ($000'S)
108 BUSINESS SUPPLY PROJECTS	Projects with just HV costs	COMPLEX CONNECTION HV (CUSTOMER CONNECTED AT HV) ($000'S)
	No new customer connected	COMPLEX CONNECTION SUB-TRANSMISSION ($000'S)
		SUBDIVISION
104 MEDIUM DENSITY HOUSING 110 LOW DENSITY HOUSING	Projects with just LV costs	COMPLEX CONNECTION LV
104 MEDIUM DENSITY HOUSING 110 LOW DENSITY HOUSING	Projects with HV costs (projects may or may not also contain LV costs)	COMPLEX CONNECTION HV (NO UPSTREAM ASSET WORKS)
	No data available to distinguish so included above	COMPLEX CONNECTION HV (WITH UPSTREAM ASSET WORKS)
		EMBEDDED GENERATION
	No new customer connected	SIMPLE CONNECTION LV
118 COGENERATION PROJECTS	Projects with HV and LV costs	COMPLEX CONNECTION HV (SMALL CAPACITY)
	No new customer connected	COMPLEX CONNECTION HV (LARGE CAPACITY)

*The exception was the split of cost codes 107 and 109. Half the projects were considered residential SIMPLE CONNECTIONS and half residential COMPLEX CONNECTION LV on the basis that undergrounding on one side of the street does not have to cross the road (simple) while connections on the other side of the street have to be connected under the street (complex). The cost split was assumed that a complex job cost 25% more than a simple job based on subject matter expert advice underpinned by contractor rates.

<u>Estimated Information:</u>

All information in Table 2.5.2 is considered an estimate. Estimates have been provided as the information requested is not separately captured by SPI Electricity and therefore requires judgment by management on how information should be obtained and presented.

Information sourced from the Fixed Asset Register is on a financial year basis (ending 31 March), not a calendar year basis. This data is considered to provide a reasonable estimate of the information required on a calendar year basis.

The information provided is considered Management's best estimate of the information required based on the data available.

2.6 Non-network

Non-network expenditure reported relates to direct Opex and direct Capex costs only. Capex and associated non-financial information has been reported against the Regulatory Year on an 'as incurred' basis. All Capex and Opex has been presented in nominal dollars.

Table 2.6.1 Non-network Expenditure

ICT and Communications Expenditure

Non-network IT & Communications Expenditure which is directly attributable to IT and communications assets including replacement, installation, operation, maintenance, licensing, and leasing costs at corporate offices has been reported. All costs associated with SCADA and Network Control Expenditure that exist beyond gateway devices have been excluded.

Expenditure reported has been allocated between 'Recurrent', 'Non-recurrent' and 'Client Devices Expenditure'.

Recurrent expenditure is all IT & communications expenditure that returns time after time, excluding any expenditure reported as Client Devices Expenditure. Temporally, expenditure that would be expected to be reasonably consistent from regulatory period to regulatory period would be classified as recurrent expenditure.

Non-recurrent expenditure is all IT & Communications Expenditure that is not Recurrent expenditure excluding any expenditure reported under Client Devices Expenditure.

Client Devices Expenditure is expenditure related to a hardware device that accesses services made available by a server. Client Devices Expenditure includes hardware involved in providing desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones, tablets and laptops

Non-network IT & Communications Expenditure has been split between Capex and Opex.

Preparation Methodology:

Opex:

Using data extracted from the Financial System for the preparation of the Annual Regulatory Accounts, the total direct costs for IT and Communications Expenditure was calculated. The total expenditure included costs for both the Electricity Distribution business and Gas Distribution business. Based on information obtained in Activity Based Costing surveys, the total Electricity Distribution IT and Communications Expenditure was calculated for each respective Regulatory Year.

The total IT cost pool was then split between recurrent and non-recurrent operating costs based on an assessment of the nature of expenditure (for example Consultancy costs are considered non-recurrent in nature). This assessment was performed by a suitable subject matter expert ("SME"). There was no Opex attributable to Client Devices.

Capex:

Data was obtained from the Financial System, from prior year Annual Regulatory Accounts and the supporting workings files. For each Regulatory Year, a list of projects and the associated financial information relating to Standard Control Services (excluding overheads) was extracted from the working files. An appropriate expert performed an assessment of the nature of each of the projects (recurrent expenditure, non-recurrent expenditure or client device expenditure) and based on this assessment, the expenditure was classified into the prescribed categorisations in Table 2.6.1.

Estimated Information:

Opex:

The allocation of Total IT and Communications expenditure between recurrent and non-recurrent expenditure was estimated based on the judgment of a SME as to the nature of the expenses in the 2009 to 2013 Regulatory Years. The information provided is Management's best estimate based on the data available.

Capex:

The allocation of Total IT and Communications expenditure between recurrent, non-recurrent and client device expenditure was estimated based on the judgment of an SME as to the nature of the projects in the 2009 to 2013 Regulatory Years. The information provided is Management's best estimate based on the data available.

Motor Vehicles

Motor Vehicle Expenditure is all expenditure directly attributable to motor vehicles including the purchase, replacement, operation and maintenance of motor vehicles assets registered for use on public roads and excluding mobile plant and equipment. It excludes expenditure on vehicles not generally moved large distances on public roads under their own power.

Car	Cars are Motor Vehicles other than those that comply with the definition of Light commercial vehicle, Heavy commercial vehicle, or Elevated Work Platform.
Heavy Commercial Vehicle (HCV)	Heavy commercial vehicles (HCVs) are Motor Vehicles that are registered for use on public roads excluding Elevated Work Platform (HCVs) that: ➢ have a gross vehicle mass greater than 4.5 tonnes; or ➢ are articulated Vehicles; or ➢ are buses with a gross vehicle mass exceeding 4.5 tonnes.

Light Commercial Vehicle (LCV)	Light commercial vehicles (LCVs) are Motor Vehicles that are registered for use on public roads excluding Elevated Work Platforms that: ➢ are rigid trucks or load carrying vans or utilities having a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; or ➢ have cab-chassis construction, and a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; or ➢ are buses with a gross vehicle mass not exceeding 4.5 tonnes.
Elevated Work Platform (EWP - HCV)	Elevated Work Platform (EWP - HCV) are HCV's that have permanently attached elevating work platforms.
Elevated Work Platform (EWP - LCV)	Elevated Work Platform (EWP - LCV) are LCV's that have permanently attached elevating work platforms.
Motor Vehicle	Is any motor vehicle registered for use on public roads excluding motor vehicles not generally moved large distances on public roads under their own power (e.g. tractors, forklifts, backhoes, bobcats and any other road registered mobile plant).

Preparation Methodology:

Opex:

For each Regulatory Year a report was generated from the Fleet System showing the total Motor Vehicle expenditure. The report provides operating expenditure for each motor vehicle and specifies vehicle type. Vehicle types were aggregated into the prescribed categories in Table 2.5.1 to determine total Opex by vehicle type. Motor Vehicle expenditure by vehicle type incorporated costs related to both the Electricity Distribution business and the Gas Distribution Business combined. Information from Activity Based Costing surveys (performed in each Regulatory Year) was used to derive an estimate of the motor vehicle expenditure (by vehicle type) in the Electricity Distribution business.

Capex:

Data was obtained from a motor vehicle report generated from the Fleet System. The report provided information in relation to the date company owned vehicles were purchased, the legal entity which purchased the vehicle, the purchase amount and the type of vehicle. Using this data, Motor Vehicle Capex was calculated for each Regulatory Year and allocated into the prescribed categorisations using the vehicle type information.

Based on this process, the Motor Vehicle expenditure by vehicle type incorporated costs related to both the Electricity Distribution business and the Gas Distribution Business combined. Information from Activity Based Costing surveys (performed in each Regulatory Year) was used to derive an estimate of the motor vehicle expenditure (by vehicle type) in the Electricity Distribution business.

Buildings and Property Expenditure

Expenditure directly attributable to non-network buildings and property assets has been reported, including the replacement, installation, operation and maintenance of non-network buildings, fittings and fixtures. It includes expenditure related to real chattels (e.g. interests in land such as a lease) but excludes expenditure related to personal chattels (e.g. furniture).

Total Buildings and Property expenditure has been reported split between Capex and Opex.

Preparation Methodology:

Opex:

A detailed Income Statement report was extracted from the Financial System for the Buildings and Property cost centres for each Regulatory Year. An analysis was performed of the general ledger accounts in the Income Statement to determine whether the costs incurred were in accordance with the Buildings and Property definition prescribed by the AER. Expenditure not directly attributable to the replacement, installation, operation and maintenance of non-network buildings, fittings and fixtures was excluded. The relevant costs were summed for each Regulatory Year and reported in Table 2.6.1.

Capex:

A project report was generated in the Financial System using the relevant Buildings and Property work codes and cost codes. The project report was reviewed and expenditure on projects which met the definition of Buildings and Property expenditure were summed and reported in Table 2.6.1.

Information presented for both Capex and Opex was extracted from financial records. As such, there is no estimated information in relation to Buildings and Property non-network expenditure.

Table 2.6.2 Annual Descriptor Metrics – IT & Communications Expenditure

Employee Numbers

Employee numbers are the average number of employees engaged in standard control services work over the year scaled for time spent on standard control services (“SCS”) work. This metric does not include labour engaged under labour hire agreements.

Preparation Methodology:

A report showing the number of full time employees and equivalents (by month) was generated in the HR/Payroll System. This report included information in relation to the 2010 to 2013 Regulatory Years and provided Employee Numbers in total across all SP AusNet businesses.

Using Activity Based Costing ("ABC") surveys, the headcount report was allocated between the Distribution (Electricity and Gas) businesses and the Transmission business. The ABC Survey information captures data relating to employees who do not work directly on projects. The information from ABC surveys has been applied to all employees in a cost centre, assuming that the survey results are applicable to employees who are directly involved in projects as well as those that are not directly involved in projects. The Electricity Distribution business headcount was further allocated into employees involved in SCS related work using an estimated percentage allocation. The SCS percentage allocation was calculated as the amount of Operating Costs relating to SCS divided by the Total Operating Costs. Information for the calculation was obtained from the Annual Regulatory Accounts.

This calculation was performed for each Regulatory Year and the resulting percentage was applied to the Electricity Distribution business average headcount to derive an estimate of 'Employee Numbers'.

In relation to the 2009 Regulatory Year, an equivalent report was unable to be generated due to a change in the Payroll/HR system. The number of employees for this Regulatory Year was calculated as the average headcount for the 2009 financial year using data obtained from the payroll system. Percentage allocations were applied to disaggregate this headcount into the Distribution (Electricity and Gas) businesses and the Transmission business. The percentages applied were derived from the ABC surveys conducted in the 2010 year. This assumes time spent by employees on activities in the different SP AusNet businesses (Transmission, Electricity and Gas Distribution) were consistent between 2009 and 2010. This is considered a reasonable assumption as there are no significant fluctuations year on year (in total) in these allocations. The 2009 ABC Survey information was unable to be applied as the headcount report was not available in the required cost centre format (to which ABC Surveys are performed).

The average employee numbers for the Electricity Distribution business in the 2009 Regulatory Year was scaled for time spent on SCS work using the percentage of Operating Costs relating to SCS divided by the Total Operating Costs for the 2009 Regulatory Year. This SCS allocation methodology is consistent with the approach applied for other Regulatory Years.

Estimated Information:

The data reported is considered estimated information due to the assumptions involved in the percentage allocations as described above. The information provided is considered Management's best estimate of the data required based on the information available.

User Numbers

User numbers are defined as active IT system log in accounts used for standard control services scaled for standard control services use.

Preparation Methodology:

User numbers were estimated to be the same as 'Employee Numbers'. Refer to discussion above in relation to the preparation methodology for 'Employee Numbers'.

Estimated Information:

This information has been estimated as it is not separately captured. The data provided is considered Management's best estimate of the information required.

Client Devices

Device numbers are defined as the number of client devices used to provide standard control services scaled for standard control services use. Client Devices are hardware devices that accesses services made available by a server.

Preparation Methodology:

Information in relation to the number of Client Devices (excluding handheld devices) was obtained from a Service Catalogue Report created using billing information provided by the IT service management provider. The report provided the number of hardware devices owned by SP AusNet, on a monthly basis. An average of the monthly devices data was calculated for each Regulatory Year.

Information in relation to handheld devices was obtained from a fixed asset database. This report provided information of the devices as at 31 March 2013 and 31 March 2012. An estimate of the 2011 to 2009 Regulatory Years was performed by scaling back the number of devices in the 2012 Regulatory Year by the year on year growth in handheld devices between 31 March 2012 and 31 March 2013. The data as at 31 March (which is SP AusNet's financial year) is deemed to approximate the data on a Regulatory Year basis.

Information in relation to smartphones was obtained from a spreadsheet database maintained by SP AusNet's Telecommunications Coordinator and the Fixed Assets Register, which records the dates on which the phones were purchased. The spreadsheet contains a list of the smart phones (and other devices, such as tablets and SIM cards) purchased, and the employee in which the device was purchased for. When the items are replaced/disposed, the spreadsheet notes this in a comments field. The number of devices purchased and still in service at the end of each reporting year was estimated using a combination of the Fixed Asset Register purchase dates, the number of records in the spreadsheet database and the comments field to arrive at the reported number. The spreadsheet database was not designed for external reporting purposes and therefore has no built in reconciliations or consistency checks (because these are not required for the spreadsheet's current purpose). Whilst the methodology used is the best available, the smartphone numbers obtained are still considered an estimate due to uncertainty about the accuracy of the data relied upon.

The three reports described above were summed to provide the total number of Client Devices across the SP AusNet businesses.

Using the same percentages applied in allocating 'Employee Numbers', average Client Devices were split between the Distribution and Transmission businesses and between the Gas Distribution and Electicity Distribution businesses. The SCS percentage was then applied to the Electricity Distribution Client Devices to derive an estimate of the variables to be reported.

Estimated Information:

Client device information is considered estimated information due to estimates involved in deriving handheld devices and the smartphone numbers. Also, approximate percentages were applied to derive an estimate of the devices owned by SPI Electricity in relation to SCS.

An estimate was required as the information is not separately captured by the business. The calculation performed is considered Management's best estimate of the required information.

Table 2.6.3 Annual Descriptor Metrics – Motor Vehicles

Average Kilometres Travelled

Preparation Methodology:

Information was sourced from the Fleet System. For the 2013 and 2012 Regulatory Years, the 'Average Kilometres Travelled' was obtained directly from the Fleet System.

For the 2009 to 2011 Regulatory Years, the 'Average Kilometres Travelled' was estimated. For these Regulatory Years, the total fuel expenditure was calculated (for vehicles which met the prescribed definition of Motor Vehicles). Using the 2012 ratio of fuel expenditure to kilometres travelled, and taking into consideration the number of vehicles in the fleet, the 'Average Kilometres Travelled' was estimated for all vehicle types for the 2009 to 2011 Regulatory Years.

The average kilometers travelled per vehicle was scaled for SCS use. The percentage of SCS use that was applied was consistent with the 'Proportion of Total Fleet Expenditure Allocated as Regulatory Expenditure' as discussed below.

Estimated Information:

This information provided is considered estimated information due to the approximation of SCS use. The data provided is considered Management's best estimate of the information required.

Number Purchased, Number Leased and Number in Fleet

Preparation Methodology:

For all Regulatory Years, information was sourced from motor vehicle reports generated from the Fleet System. The system reports were analysed and vehicles which did not meet the prescribed Motor Vehicle definition were excluded. Based on information in the reports, the 'Number Purchased', the 'Number Leased' and 'Number in Fleet' were calculated. There was a Fleet System change in 2011, however, the historic data was migrated into the new system, as such the system change did not impact the reports generated.

The number of vehicles in the fleet purchased, the number of vehicles leased in the fleet and the number of vehicles in the fleet were scaled for SCS use. The percentage of SCS use that was applied was consistent with the 'Proportion of Total Fleet Expenditure Allocated as Regulatory Expenditure' as discussed below.

Estimated Information:

This information provided is considered estimated information due to the approximation of SCS use. The data provided is considered Management's best estimate of the information required.

Proportion of Total Fleet Expenditure Allocated as Regulatory Expenditure

Preparation Methodology:

The 'Proportion of Total Fleet Expenditure Allocated as Regulatory Expenditure' was calculated based on information contained in the Annual Regulatory Accounts. The percentage reported is the amount of Operating Costs relating to Standard Control Services divided by the total Operating Costs. This calculation was performed for each Regulatory Year.

Estimated Information:

The percentage reported is considered estimated information as it has been assumed that the proportion of 'Total Fleet Expenditure Allocated to Regulatory Expenditure' is consistent with the proportion of Total Operating Expenditure Allocated to Regulatory Expenditure. The data provided is considered Management's best estimate of the information required.

2.7 Vegetation management

Vegetation management zones are segments of the distribution network distinguished from other vegetation management segments by material differences in recognised cost drivers.

An assessment of vegetation management zones has been performed taking into consideration areas where bushfire risk mitigation costs are imposed by legislation, regulation or ministerial order and areas of the network where other recognised drivers affect the costs of performing vegetation management work. The key driver of vegetation management costs across SP AusNet's businesses is the level of bushfire risk. Based on this, two vegetation management zones were identified in SPI Electricity's network - high bush fire risk areas ("HBRA") and low bushfire risk areas ("LBRA").

The Electrical Safety (Electric Line Clearance) Regulations impose a material cost on performing vegetation management works. The cost of compliance is consistent with the information reported in Table 2.7.2.

There are no self-imposed standards per SPI Electricity's Vegetation Management program.

Table 2.7.1 – Descriptor Metrics by Zone

Route Line Length within Zone

The route line length is the aggregated length in kilometers of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.

Preparation Methodology:

For the 2013 Regulatory Year, total line length data was extracted from the Asset Management System.

Total route line lengths prior to the 2013 Regulatory Year were estimated based on historical circuit length data. The estimation was derived by calculating the ratio of route line length to circuit length for the 2013 Regulatory Year. This ratio was applied to the 2009 to 2012 Regulatory Years to estimate the route line length. Estimation is required because route line length data have not been previously recorded or reported. It is not possible to generate historic information on route line lengths from existing source systems.

The split of total route line length between the HBRA and LBRA vegetation management zones was performed on a percentage allocation basis. The percentage applied was derived using line length information (split between HBRA 81% and LBRA 19%) from the Regulatory Impact Statement in the 2013

Regulatory Year. The Short and Long Rural and Urban split (98% and 2% respectively) was also calculated based on line length information from the Regulatory Impact Statement in the 2013 Regulatory Year.

Estimated Information:

The data provided is considered estimated information for all Regulatory Years due to the estimates involved in the allocation percentages applied. The information provided is considered Management's best estimate based on available data.

Number of Maintenance Spans

The 'Number of maintenance spans' is the total count of spans in the network that are subject to active vegetation management practices in the relevant Regulatory Year.

Preparation Methodology:

Maintenance span is the network span that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include inspection of vegetation maintenance spans where 'inspection' is only for the purpose of identifying trees or other vegetation that require trimming or removal and include vegetation scoping works.

Urban and CBD maintenance spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant Regulatory Year. CBD and urban areas are consistent with CBD and urban customer classifications.

Rural maintenance spans refer to spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders.

Urban and Rural maintenance spans were determined using information extracted from the Vegetation Management system which was split into zone (HBRA and LBRA) and area category (Urban and Rural) using feeder data. The information is further disaggregated into maintenance spans and spans clear of vegetation. Maintenance spans were determined as PT1 to PT720 per the system data (which denotes spans where vegetation maintenance is required in the next 720 days).

Total Length of Maintenance Spans

Preparation Methodology:

HBRA: The 'Total Length of Maintenance Spans' was calculated by dividing the total line length in kilometres for HBRAs (per the Vegetation Management System) by the total number of towers in HBRAs (per the Vegetation Management System) to derive an estimate of the average kilometre line length for each tower in a HBRA. This average was multiplied by the number of HBRA maintenance spans (in Urban areas and CBD areas) to derive an estimate of 'Total Length of Maintenance Spans' in Urban and CBD areas in each Regulatory Year.

LBRA: The 'Total Length of Maintenance Spans' was calculated by dividing the total line length in kilometres for LBRAs (per the Vegetation Management System) by the total number of towers in LBRAs (per the Vegetation Management System) to derive an estimate of the average kilometre line length for each tower in a LBRA. This average was multiplied by the number of LBRA maintenance spans (in Urban areas and CBD areas) to derive an estimate of 'Total Length of Maintenance Spans' in Urban and CBD areas in each Regulatory Year.

Estimated Information:

Data provided is considered estimated information as it is not separately captured. The calculation performed assumes that there is one tower per maintenance span. The calculation also assumes that the average kilometer line length for each tower is consistent across all Regulatory Years. The calculations performed are considered the best estimate of the data requested based on the information available.

Average Number of Trees per Maintenance Span

The 'Average number of trees per maintenance span' includes only trees that require active vegetation management to meet its vegetation management obligations during a 3 year cycle. It excludes trees that only require inspections and no other vegetation management activities required to comply with SPI Electricity's vegetation management obligations.

Preparation Methodology:

The average number of trees per urban and rural vegetation maintenance spans was estimated. In 2009, a random sample (across the network) was performed of the total trees being maintained to preserve regulatory clearance space. Based on the sample results, a percentage of trees being maintained relative to spans was calculated. This percentage was applied to the total number of vegetation maintenance spans (for the Central, North and East regions within SPI Electricity's network) in the 2013 Regulatory Year to derive an estimate of the average number of trees in the 2013 Regulatory Year.

It has been assumed that the average number of trees in urban vegetation maintenance spans is consistent with the average number of trees in rural vegetation maintenance spans as the random sample did not distinguish between urban and rural data. Additionally, it has been assumed that the average number of trees per vegetation maintenance span in the current year is consistent with previous Regulatory Years. It has also been assumed that the average number of trees is consistent in HBRAs and LBRAs.

Estimated Information:

Management considers the above to be the best estimates of the information required based on available data.

Length of Vegetation Corridors

A Vegetation corridor is a tract of land along which vegetation is maintained in order to form a passageway along the route of a power line or lines that is free of vegetation encroachment into the asset clearance space. This does not include portions of the corridor where no managed vegetation exists or where vegetation is not managed.

<u>Preparation Methodology:</u>

The 'Length of Vegetation Corridors' was calculated by using information from the Vegetation Management System.

HBRA: For each Regulatory Year, the total number of urban and rural PT720 and RE (reassess) vegetation maintenance spans was obtained (which represent maintenance spans which require vegetation maintenance in the next 2 years and spans which need to be reassessed). This total was multiplied by the average length of a transmission span (as derived in the calculation of 'Total Length of Maintenance Spans') to provide an estimate of the 'Length of Vegetation Corridors'.

LBRA: For each Regulatory Year, the total number of urban and rural PT720 and RE (reassess) vegetation maintenance spans was obtained (which represent maintenance spans which require vegetation maintenance in the next 12 months). This total was multiplied by the average length of a transmission span (as derived in the calculation of 'Total Length of Maintenance Spans') to provide an estimate of the 'Length of Vegetation Corridors'.

<u>Estimated Information:</u>

The data provided is considered estimated information as it is not separately captured. This is considered the best estimate of the information requested.

Average Frequency of Cutting Cycle

The cutting cycle is the average planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed within vegetation management zones. It has been assumed that Cutting cycles are the same as Maintenance span cycles (the planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed).

<u>Preparation Methodology:</u>

Information in relation to the average vegetation maintenance span cycles was obtained from the Vegetation Management system and also per the vegetation management plan. The cycle data provided was available in the HBRA and LBRA cutting frequencies. As such, no estimation was required.

Table 2.7.2 – Expenditure Metrics by Zone

Table 2.7.2 has been completed based on the two vegetation management zones identified above. Expenditure provided relates to direct costs, it excludes overhead expenditure and has been presented in nominal dollars. Annual vegetation management expenditure across all categories and zones sums to the total Vegetation Management expenditure in each Regulatory Year.

<u>Preparation Methodology:</u>

Expenditure recorded on Vegetation Management in the Distribution business is coded to specific project codes that align to different vegetation management functions. This data is posted to one work code in SPI Electricity's general ledger and projects ledger.

To populate Table 2.7.2, expenditure on each project in the Vegetation Management work code was extracted from the Financial System. This data extract was then subject to further analysis.

'Tree Trimming' and 'Inspection' project codes allow for a direct one-for-one allocation from the Financial System extract and the categories in Table 2.7.2 (both function and zone).

'Hazard Tree Cutting', 'Ground Clearance' and 'Vegetation Corridor Clearance' can be allocated directly to functions from the project codes, but not to the two Vegetation Management zones (HBRA and LBRA). Expenditure was allocated to the zones based on the 'Tree Trimming' and 'Inspection' proportions (for 'Ground Clearance' and 'Vegetation Corridor Clearance') and the number of hazard trees attended to (for 'Hazard Tree Cutting').

'Audit' and 'Contractor Liaison' expenditure is not separately identifiable in the Vegetation Management work code. To derive these amounts, the most recent year of actual expenditure (Regulatory Year 2013) was estimated based on the number of staff in each role, multiplied by an average annual salary. The expenditure for the 2009 to 2012 Regulatory Years was derived by reducing the 2013 value by an estimated percentage rate.

The costs included in the category 'Other Vegetation Management Costs not Specified in the Sheet' reflect the balance of costs between the above categories and the total expenditure derived from the Vegetation Management work code Financial System extract. Other costs reflect activities such as trouble orders, bark patrol and track maintenance.

Differences in total between the above determined costs and the Annual Regulatory Accounts were calculated and the resulting amount was scaled on a proportional basis to ensure data reported aligns with the Annual Regulatory Accounts. The differences reflect any unregulated costs or any emergency vegetation management costs (which are separately reported in Template 2.9 Emergency Response).

Estimated Information:

All Vegetation Management expenditure reported is considered estimated information. This is due to the estimations involved in the category allocations of total costs, estimates involved in deriving the HBRA and LBRA zone splits (for all categories except 'Tree Trimming' and 'Inspection') and estimates involved in calculating 'Audit' and 'Contractor liaison' costs.

Information was estimated as data is not captured in the categories required. Data provided is considered Management's best estimate based on the information available.

Table 2.7.3 – Descriptor Metrics Across All Zones – Unplanned Vegetation Events

Unplanned vegetation events are system outages and fire starts caused by either vegetation grow-ins or vegetation blow-ins/fall-ins.

Number of Fire Starts Caused by Vegetation Grow-Ins (NSP Responsibility), Number of Fire Starts Caused by Blow-Ins and Fall-Ins (NSP Responsibility), Number of Fire Starts Caused by Vegetation Grow-Ins (Other Party Responsibility) and Number of Fire Starts Caused by Blow-Ins and Fall-Ins (Other Party Responsibility)

Preparation Methodology:

A review of information contained in the Incident Management System was performed for the 2009 to 2013 Regulatory Years. Based on this review, Fire Starts were identified. There was insufficient data in the system to determine the cause of the fire starts (grow-ins, blow-ins or fall-ins) or the responsibility. As such it has been assumed that all Fire Starts relate to Blow-Ins and Fall-Ins are SPI Electricity's responsibility.

Estimated Information:

The information provided is considered estimated information due to the assumption discussed above. This is considered Management's best estimate based on the information available.

2.8 Maintenance

Maintenance relates to operational repairs and maintenance of the distribution system, including testing, investigation, validation and correction costs not involving capital expenditure.

Table 2.8.1 – Descriptor Metrics for Routine and Non-Routine Maintenance

A 'Maintenance cycle' is the planned or actual duration between two consecutive maintenance works on an asset. An 'Inspection cycle' is the planned or actual duration between two consecutive inspections of an asset.

The 'Inspection cycle' and the 'Maintenance cycle' for each maintenance subcategory have been expressed as the number of years in the respective cycles. Where there are multiple inspection and maintenance activities, the cycle that reflects the highest cost activity has been reported.

Asset quantity information has been provided for the total number of assets (population) at the end of the respective Regulatory Years (for each asset category) and the number of assets inspected or maintained during the respective Regulatory Years (for each asset category).

Asset Quantity at Year End

Preparation Methodology:

In relation to the asset categories listed below in Table A, data reported for 'Asset Quantity at Year End' was sourced from Template 5.2 Asset Age Profile.

Table A.

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity	Relevant categories in Template 5.2
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	POLE TOPS AND OVERHEAD LINES	NUMBER OF POLES (000'S)	Asset Type: Poles Asset Category: Other cross arm assets
POLE INSPECTION AND TREATMENT	ALL POLES	NUMBER OF POLES (000'S)	Asset Type: Poles Asset Category: All poles, excluding cross arm assets
POLE INSPECTION AND TREATMENT	ALL OVERHEAD ASSETS	LINE PATROLLED (ROUTE KM) (000'S)	Asset Type: Overhead Conductor Asset Category: All
NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE	LV - 11 TO 22 KV	LENGTH (KM) (000'S)	Asset Type: Underground Cables Asset Category: < = 1 kV to > 11 kV & < = 22 kV
	33 KV AND ABOVE	LENGTH (KM) (000'S)	Asset Type: Underground Cables Asset Category: < = 1 kV to > 11 kV & < = 22 kV

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity	Relevant categories in Template 5.2
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION TRANSFORMERS	NUMBER OF INSTALLED TRANSFORMERS (000'S)	Asset Type: Transformers Asset Category: POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE to GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 40 MVA
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION SWITCHGEAR (WITHIN-SUBSTATIONS AND STAND-ALONE SWITCHGEAR)	NUMBER OF SWITCHES (000'S)	Asset Type: Switchgear Asset Category: All
SCADA & NETWORK CONTROL MAINTENANCE	SCADA & NETWORK CONTROL MAINTENANCE	FIELD DEVICES, LOCAL NETWORK WIRING ASSETS and COMMUNICATIONS NETWORK ASSETS	Asset Type: Scada, Network Control & Protection Systems Asset Category: Field devices to Communications Network Assets
PROTECTION SYSTEMS MAINTENANCE	PROTECTION SYSTEMS MAINTENANCE	RELAYS AND BATTERIES	Asset Type: Scada, Network Control & Protection Systems Asset Category: Relays and Batteries

For the 2013 Regulatory Year, 'Asset Quantity' was calculated as the cumulative sum of the relevant categories (as listed in Table A above) in Template 5.2 Asset Age Profile.

For the 2012 Regulatory Year, the total assets installed in the 2013 Regulatory Year (per Template 5.2 Asset Age Profile) were subtracted from the 2013 reported 'Asset Quantity' to derive the 2012 'Asset Quantity' and the quantity replaced (per Template 2.1 Repex) was added. This process was followed for all required Regulatory Years and all categories listed above.

Table B.

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity
NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE	CBD	LENGTH (KM) (000'S)
	NON-CBD	LENGTH (KM) (000'S)

In relation to Table B above, the total Underground Cable length in kilometers (the sum of 'LV - 11 to 22 KV' and '33 KV and above') has been reported in the Non-CBD category as SPI Electricity does not own underground cable in CBD areas.

Table C.

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	SERVICE LINES	NUMBER OF CUSTOMERS (000'S)

The 'number of customers' in relation to Service Lines (refer to Table C above) has been calculated based on the total number of customers (per the Economic Benchmarking Report) multiplied by the estimated percentage of overhead customers in the 2013 Regulatory Year (as determined by an SME). This information was cross-checked using information sourced from the SDME system. A report was generated which showed the total number of services in the network split by service type into overhead, underground and unspecified. The unspecified network service data was allocated into overhead and underground based on percentages derived from the known information. This data was materially consistent with the estimate performed.

The 2013 estimated information was de-escalated over the 2009 to 2012 Regulatory Years based on the number of overhead new connections per data compiled for Template 2.5 Connections.

Table D.

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity
OVERHEAD ASSET INSPECTION	ALL OVERHEAD ASSETS	LINE PATROLLED (ROUTE KM) (000'S)

The Overhead Asset Inspection 'Line Patrolled' (as shown in Table D above) has been disclosed as the route line length. The route line length is the aggregated length in kilometers of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.

For the 2013 Regulatory Year, line length data was extracted from the Asset Management System. Prior to the 2013 Regulatory Year, route line lengths were estimated based on historical circuit length data. The estimation was derived by calculating the ratio of route line length to circuit length for the 2013 Regulatory Year. This ratio was applied to the 2009 to 2012 Regulatory Years to estimate the route line length information.

Table E.

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION - PROPERTY	NUMBER OF DISTRIBUTION SUBSTATION PROPERTIES MAINTAINED (000'S)

The Number of Distribution Substation Properties Maintained was calculated using information sourced from the GIS System. The number calculated included kiosk substations, pad mounted substations, indoor substations and ground substations. The year on year change in Distribution Substation Properties is consistent with data included in Template 2.3 Augex.

Table F.

Maintenance Activity	Maintenance Asset	Unit of Measure – Asset Quantity
ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - ZONE SUBSTATION	NUMBER OF ZONE SUBSTATION TRANSFORMERS (000'S)
	TRANSFORMERS - DISTRIBUTION	NUMBER OF DISTRIBUTION TRANSFORMERS WITHIN ZONE SUBSTATIONS (000'S)
	TRANSFORMERS - HV	NUMBER OF HV TRANSFORMERS (000'S)
	ZONE SUBSTATION - OTHER EQUIPMENT	OTHER
	ALL ZONE SUBSTATION PROPERTIES	NUMBER OF ZONE SUBSTATION PROPERTIES MAINTAINED (000'S)

For all Regulatory Years, the number of Zone Substation Transformers was extracted from the Maximo Asset Management System and current internal document 'Asset Condition Data Sheet for ZSS transformers', collated for the EDPR submission.

The number of Zone Substation - Other Equipment assets has been estimated based on the number of circuit breakers plus an escalation factor (of 163%) to estimate other assets including 66kv isolators/ disconnectors and 66kv instrument transformers (CTs and VTs) only, which are maintained on a regular basis. The percentage estimate was performed by a relevant SME. The number of circuit breakers was obtained from the Maximo Asset Management System and EDPR Asset Condition Data Sheet for all Regulatory Years.

Information in relation to the number of Zone Substation Properties was obtained from the SP AusNet internal document 'PGI 67-01-01 List of Transmission and subtransmission Stations and communication sites', the EDPR Asset Condition Data Sheet and the Asset Management System for all Regulatory Years. Each Zone Substation is assumed to be one property including buildings, fences, drainage, switchyard surfaces/access roads, metallic structures etc.

Estimated Information:

The data provided as listed under Table A above is considered estimated information (for all Regulatory Years), based on assumptions and estimates included in preparing Template 5.2 Asset Age Profile.

The 'number of customers' (in relation to Service Lines) is estimated information as the required data was not available in SPI Electricity's systems. The calculation methodology and assumptions applied have been outlined above.

Route line length was estimated as route line length data has not been previously recorded or reported. It is not possible to generate historic information on route line lengths from existing source systems.

The number of distribution substation properties was estimated for the 2013 Regulatory Year using data extracted from the Asset Management System. The information extracted from the Asset Management Systems is current data as at May 2014. This is due to the Asset Management Systems being 'live' databases. System limitations prevent asset reports being run as at specific (historic) points in time. The number of distribution substation properties was estimated for the 2009 to 2012 Regulatory Years based on the percentage movement in the number of Distribution Substation Transformers.

The quantity of Zone Substation - Other Equipment assets has been estimated using information from the Asset Management System and assumptions of an SME.

The data provided is considered Management's best estimate based on the information available.

Average Age of Asset Group

Preparation Methodology:

For the categories listed in Table G below, the 'Average Age of Asset Group' was sourced from the Replacement Expenditure model (model template provided by the AER in 2012).

Table G.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	POLE TOPS AND OVERHEAD LINES
	SERVICE LINES
POLE INSPECTION AND TREATMENT	ALL POLES
OVERHEAD ASSET INSPECTION	ALL OVERHEAD ASSETS
NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE	LV - 11 TO 22 KV
	33 KV AND ABOVE
	NON-CBD
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION TRANSFORMERS
	DISTRIBUTION SUBSTATION SWITCHGEAR

ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - ZONE SUBSTATION
	ZONE SUBSTATION - OTHER EQUIPMENT
SCADA & NETWORK CONTROL MAINTENANCE	SCADA & NETWORK CONTROL MAINTENANCE
PROTECTION SYSTEMS MAINTENANCE	RELAYS AND BATTERIES

The Replacement Expenditure model was populated with current data extracted from the Asset Management System in May 2014. The asset life data in the model was developed based on engineering judgment from subject matter experts within the business. The asset categories in the Replacement Expenditure model have been aligned with the AER asset categories outlined above.

The 'Average Age of Asset Group' was calculated as the calculated Weighted Average Life (per the Repex Model) less the calculated Weighted Average Remaining Life (per the Repex Model) for the assets included in the prescribed categories.

In relation to Overhead Asset Inspection – All Overhead Assets, the calculation was performed based on Overhead Conductor.

The average age of Distribution Substation Property was calculated as the average age of all Distribution Substation Properties using information obtained from the Maximo Asset Management System and the 'Asset Condition Data sheet' prepared for the EDPR. This data was used as a proxy to estimate the average age of All Zone Substation Properties as the required information was not available.

Estimated Information

As outlined above, all information provided is considered estimated information. Information is considered Management's best estimate, based on the data available.

Asset Quantity Inspected/Maintained

Preparation Methodology:

For the maintenance activities listed in Table H below, the number of assets inspected or maintained was obtained from the Asset Management System based on work orders. The relevant work order data was extracted by selecting the relevant system classifications and work specs. The data was summed to derive the 'Asset Quantity Inspected/Maintained' for each Regulatory Year. The knowledge of a SME was applied to determine the allocation of work orders into prescribed Maintenance Asset Category. The data extracted was based on an SPI Electricity financial year basis, not a calendar year basis (due to system limitations).

Table H.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	POLE TOPS AND OVERHEAD LINES
	SERVICE LINES
POLE INSPECTION AND TREATMENT	ALL POLES
OVERHEAD ASSET INSPECTION	ALL OVERHEAD ASSETS
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION TRANSFORMERS
	DISTRIBUTION SUBSTATION SWITCHGEAR (WITHIN-SUBSTATIONS AND STAND-ALONE SWITCHGEAR)
	DISTRIBUTION SUBSTATION - PROPERTY

In relation to Distribution Substation Equipment and Property Maintenance, a report of work orders was extracted from the Asset Management system. Where the WO descriptions could be aligned to Transformers and Switchgear categories, the count of these work orders has been reported as the Asset Quantity Inspected/Maintained for these asset categories. The remaining population of work orders has been disclosed as the Quantity Inspected/Maintained for Distribution Substation Property.

As Underground cable assets are not inspected or maintained, 'Asset Quantity Inspected/Maintained' has been reported as zero for all Regulatory Years.

Table I.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - ZONE SUBSTATION
	TRANSFORMERS - DISTRIBUTION
	TRANSFORMERS - HV
	ZONE SUBSTATION - OTHER EQUIPMENT
	ALL ZONE SUBSTATION PROPERTIES
SCADA & NETWORK CONTROL MAINTENANCE	SCADA & NETWORK CONTROL MAINTENANCE
PROTECTION SYSTEMS MAINTENANCE	RELAYS AND BATTERIES

Information provided has been calculated as the sum of the 'Asset Quantity at Year End' divided by the 'Inspection Cycle' in years and 'Asset Quantity at Year End' divided by the 'Maintenance Cycle' in years. For these maintenance categories, the calculation performed is considered to be more indicative of the quantity inspected and maintained than information from other sources.

The information provided in relation to 'Asset Quantity Inspected/Maintained' is considered estimated information as it has been assumed that actual maintenance performed is aligned with the policy (and no non-routine maintenance is required).

Estimated Information:

As outlined above, all information provided is considered estimated information. Information provided is considered Management's best estimate, based on the data available.

Inspection Cycle and Maintenance Cycle

Data provided in relation to Inspection and Maintenance Cycles is in relation to the 2013 Regulatory Year.

Preparation Methodology:

Table J.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	POLE TOPS AND OVERHEAD LINES
POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	SERVICE LINES
POLE INSPECTION AND TREATMENT	ALL POLES
OVERHEAD ASSET INSPECTION	ALL OVERHEAD ASSETS

The inspection cycles in relation to the above asset categories was estimated based on cycles contained in the SP AusNet internal policy document 'Asset Inspection Manual'. The estimation was performed by a relevant SME. In relation to the Maintenance Cycle, the above listed assets are subject to 'condition based' maintenance only. No planned maintenance is undertaken. Based on this, the maintenance cycle has been populated as zero.

Table K.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE	LV - 11 TO 22 KV
	33 KV AND ABOVE

As Underground cable assets are not inspected or maintained, 'Inspection Cycles' and 'Maintenance Cycles' of zero have been reported.

Table L.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION TRANSFORMERS
	DISTRIBUTION SUBSTATION SWITCHGEAR (WITHIN-SUBSTATIONS AND STAND-ALONE SWITCHGEAR)
	DISTRIBUTION SUBSTATION - PROPERTY

In relation to Distribution Substation Transformers, the 'Inspection Cycle' reported is based on the inspection cycle of pole mounted transformers as ground mounted transformers are not routinely inspected (unless they are at a key switch location). Pole mounted transformers are inspected as part of the overhead line routine patrol which is performed based on a 3.5 year cycle. The inspection cycle reported is considered Management's best estimate of the required data.

Distribution Substation Transformers are not subject to a routine maintenance cycle. Generally, distribution transformers assets are run to failure (failures are pre-empted by load profile review etc). This is supported by the minimal number of work orders for Transformer maintenance. Based on this, the 'Maintenance Cycle' has been reported as zero.

Distribution Substation Switchgear is not routinely inspected. Based on this, the inspection cycle has been reported as zero. Maintenance is conducted on switches that have been identified as 'key switches' according to various timescales. The frequency for gas switch, ring main units maintenance is approximately 10 years based on information sourced from the Q4 Asset Management System. As such, this has been used as the basis for the 'Maintenance Cycle' reported.

The Inspection Cycle of Distribution substation property has been reported as 3.5 years. This is based on the inspection cycle of ground type distribution substations which are inspected as part of the bundled line patrol. They are not subject to a routine maintenance cycle.

Other Equipment is not subject to routine maintenance. Based on this, the Maintenance Cycles have been reported as zero. Inspections are on an ad hoc basis. The data provided has been calculated by dividing the quantity of assets on hand in 2013 by the quantity of assets inspected. This is considered to provide an estimate of the data required.

Table M.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - ZONE SUBSTATION

The Maintenance Cycle of Transformers was calculated as the average maintenance cycle based on the age of the transformer assets. A 2 year routine maintenance cycle is required for older transformers, newer transformers require a 4 year maintenance cycle and very new transformers require minor maintenance work every two years but major work every 12 years. This information was extracted from the SP AusNet internal policy document 'PGI 02-01-04 Summary of Maintenance Intervals Distribution Zone Substations' and is also based on the knowledge of SMEs, asset conditions and manufacturer recommendations.

The inspection cycles reported for Transformers was based on the frequency of oil sampling which is performed on an annual basis for all transformers. This is based on the knowledge of subject matter experts, asset conditions and manufacturer recommendations.

Table N.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
ZONE SUBSTATION EQUIPMENT MAINTENANCE	ZONE SUBSTATION - OTHER EQUIPMENT

The Maintenance Cycle of Zone Substation - Other Equipment has been estimated as the number of routine maintenance performed on circuit breakers and isolators/disconnectors. The majority of the older circuit breakers are on a 4 year maintenance cycle with the remaining circuit breakers on an 8 year cycle. All isolator/disconnector maintenances are on an 8 year cycle. This information was extracted from the SP AusNet internal policy document 'PGI 02-01-04 Summary of Maintenance Intervals Distribution Zone Substations' and is also based on the knowledge of subject matter experts, asset conditions and manufacturer recommendations.

The inspection cycles reported for Other Equipment is inspected on an annual basis based on information in SP AusNet policy 'PGI 02-01-04 Summary of Maintenance Intervals Distribution Zone Substations', the knowledge of subject matter experts, asset conditions and manufacturer recommendations.

Table O.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
ZONE SUBSTATION EQUIPMENT MAINTENANCE	ALL ZONE SUBSTATION PROPERTIES

Zone Substation civil inspections are conducted every month/three months, in general, based on information contained in internal policy 'PGI 67-01-01' and the site risk associated with stations. Also the inspections intervals are adjusted based on locations and criticality of the zone substation. The interval could vary from monthly to three monthly and even six monthly in some cases. The average has been estimated as three monthly for every zone substation.

Maintenance is performed on a 'condition-basis' only. For the purposes of complying with the RIN requirements, the template has been completed as 0.5 years which was calculated as the quantity of assets in age group and expected maintenance works generated due to identified defects during each inspection for each age group.

Table P.

MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY
SCADA & NETWORK CONTROL MAINTENANCE	SCADA & NETWORK CONTROL MAINTENANCE
PROTECTION SYSTEMS MAINTENANCE	PROTECTION SYSTEMS MAINTENANCE

Data provided was extracted from the SP AusNet internal policy document 'PGI-MTCE INTERVALS-DISTN - Summary of Maintenance Intervals – Distribution Zone Substations' as the maintenance interval for Protection Schemes. The inspection and maintenance cycles are the same for Protection System assets as inspection and maintenance is performed simultaneously.

<u>Estimated Information:</u>

The data provided are considered Management's best estimate, based on the information available.

Table 2.8.2 – Cost Metrics for Routine and Non-Routine Maintenance

Maintenance expenditure has been provided for each of the prescribed maintenance categories and has been presented in nominal dollars. Expenditure reported relates to Direct Costs only and excludes expenditures on Overheads.

Expenditure incurred for the simultaneous inspection of assets and vegetation or for access track maintenance, has been included in Template 2.7 Vegetation Management and not in Template 2.8 Maintenance. Expenditure has been classified as Routine and Non-routine Maintenance Costs.

Routine maintenance costs are costs of recurrent/programmed activities undertaken to maintain assets, performed regardless of the condition of the asset. Costs of activities are predominantly directed at discovering information on asset condition, and often undertaken at intervals that can be predicted.

Activities to maintain asset condition and/or to maintain the capacity of the distribution system to distribute electricity, and where the activities are:

- routine in nature; and
- indiscriminately carried out for a pre-defined set of assets; and
- scheduled to occur at pre-defined intervals.

Routine maintenance may include activities to inspect, survey, audit, test, repair, alter, or reconfigure assets.

Routine maintenance expenditure excludes the costs of activities that are designed to increase or improve the capacity of the distribution system to distribute electricity, except where the increase or improvement is incidental to the maintenance of the distribution system. It also excludes costs associated with asset removal, asset replacement, new asset installation, vegetation management and emergency response.

Non-routine maintenance costs are costs of activities predominantly directed at managing asset condition or rectifying defects (excluding emergency call-outs). The timing of these activities depends on asset condition and decisions on when to maintain or replace the asset, which may vary over time.

Non-routine maintenance is activities to maintain asset condition and/or to maintain the capacity of the distribution system to distribute electricity, and where the activities are not routine in nature.

Non-routine maintenance expenditure excludes activities that are designed to increase or improve the capacity of the distribution system to distribute electricity, except where the increase or improvement is incidental to the maintenance of the distribution system. It also excludes costs associated with asset removal, asset replacement, new asset installation, vegetation management and emergency response.

Preparation Methodology:

Expenditure on maintenance works (and other non-maintenance costs) is coded to work codes and recorded in SPI Electricity's general ledger and projects ledger. These costs do not include overheads. Expenditure by work code was extracted from the Financial System for each Regulatory Year. The maintenance work codes were segregated from the non-maintenance work codes.

These maintenance work codes were then subject to a review by subject matter experts and allocated into the prescribed categories. Where necessary, work codes were split into 'task codes', which is a further disaggregation available within work codes (i.e. work codes are comprised of task codes).

It is important to note that the costs presented in the various rows of Table 2.8.2 are not necessarily mutually exclusive of other rows in the same table. For example, 'Network Underground Cable Maintenance' is reported both by voltage and by location, in the same table. To sum these amounts together would double count these maintenance costs. In accordance with guidance from the AER, an additional row ('Duplications') has been included in Table 2.8.2 to remove these duplications.

Estimated Information:

All data provided is considered estimated information.

SPI Electricity does not internally report on Routine and Non-Routine Maintenance costs separately. Based on this, work codes are not set up to provide this level of detail. The allocation between Routine and Non-Routine Maintenance was based on the judgment of subject matter experts familiar with the work codes. Routine and non-routine allocations for the 2009 to 2011 Regulatory Years were based on workings provided during the 2011-15 EDPR. Allocations were updated in the 2012 and 2013 Regulatory Years and reported in the Annual Regulatory Accounts.

A degree of judgment was also required to allocate expenditure in each work code to the categories required in the templates. SMEs were again engaged to derive these allocations.

Information provided is considered Management's best estimate of the information required, based on the data available.

2.9 Emergency Response

Emergency response expenditure relates to costs incurred to restore a failed component to an operational state including all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and/or repairs necessary.

Emergency response includes costs of activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.

Table 2.9.1 – Emergency Response Expenditure (Opex)

Total Emergency Response Expenditure

Preparation Methodology:

For the 2010 to 2013 Regulatory Years, Total Emergency Response expenditure was extracted from the Annual Regulatory Accounts. Amounts included in the Annual Regulatory Accounts were based on information sourced from the Financial System. A suitable expert reviewed the data by work codes to determine the percentage to be allocated to Emergency Response expenditure for each Regulatory Year.

For the 2009 Regulatory Year, Total Emergency Response expenditure was not required to be separately disclosed in the Annual Regulatory Accounts. As such, to derive the required financial information, a calculation was performed to estimate the Total Emergency Response expenditure for the 2009 Regulatory Year. Financial information for 2009 was extracted from the Financial System and the Total Emergency Response expenditure was calculated by applying the same percentage allocations and methodology used in the 2010 Regulatory Year.

Estimated Information:

As discussed above, data for the 2009 Regulatory Year has been estimated using 2009 financial information and applying the percentage allocation methodology from the 2010 Regulatory Year. This is considered Management's best estimate based on the information available.

Major Events O&M Expenditure (Major Storm)

A major storm is a tropical cyclone of Category 1 or above as classified by the Australian Bureau of Meteorology. There are no tropical cyclone occurrences in SPI Electricity's network.

Estimated Information:

Major Event Days O&M Expenditure

Major Event Days ("MEDs") are defined as per the meaning specified in the service target performance incentive scheme ("STPIS").

Preparation Methodology:

The MEDs reported are consistent with the MED days identified for Template 6.3 Sustained Interruptions.

The MED threshold was calculated for the 2013 Regulatory Year from the daily Unplanned System Average Interruption Duration Index ("SAIDI") data between Regulatory Years 2008 and 2012 (5 years) using the annual AER RIN Template MED calculator. Calculations performed were in accordance with the requirements of the STPIS. The calculated MED threshold was then applied as the threshold for all Regulatory Years for the purpose of identifying MEDs.

Emergency response expenditure attributable to MEDs is not separately captured in the Financial System. Expenditure for the MEDs on 4 June 2012, 5 September 2012 and 26 September 2013 has been calculated by reviewing data in the relevant work codes and supporting information from contractor invoices. This process was undertaken for the purpose of collating data for the Annual Regulatory Accounts.

For all other MEDs, the financial information was estimated by calculating an average cost per Network SAIDI (excluding events) based on the 4 June 2012 and 5 September 2012 MEDs and applying this average to the Network SAIDI (excluding events) for all other MEDs. 26 September 2013 was not incorporated into this calculation as it is considered an outlier of the 3 events. The proportion of Opex costs incurred on the 26 September 2013 MED is not considered representative of Opex costs typically incurred on MEDs – as more repair and maintenance work was performed and less expenditure was capitalised.

Estimated Information:

The financial information provided under 'Major Event Days O&M Expenditure' is considered Estimated Information with the exception of the financial data for MEDs on 4 June 2012, 5 September 2012 and 26 September 2013.

The information provided is considered Management's best estimate based on the data available.

2.10 Overheads Expenditure

Overhead Expenditure is expenditure that cannot be directly attributed to a work activity, project or work order and consists of labour, materials, contract costs and other costs.

Overhead Expenditure has been disaggregated as Network Overheads and Corporate Overheads.

Table 2.10.1 – Network Overheads Expenditure

Overhead expenditure has been reported in Table 2.10.1 before it is allocated to services or direct expenditure and before any part of it is capitalised.

Network Overhead costs refer to the provision of management services and other related operational, network planning, asset management and compliance functions that cannot be directly associated with any specific operational activity (such as routine maintenance, vegetation management, etc.). Network Overhead includes expenditure for Network Management, Network Planning, Network Control, Quality and Standard Functions, Project Governance & Related Functions and Other network operating costs. These expenditure categories are defined below.

- Network Management – expenditure not directly related to any of the functions listed below.
- Network Planning - includes all costs associated with developing visions, strategies, or plans for the development of the network. This includes functions such as demand forecasting, network analysis, preparation of planning documentation, area plans, and the like, as well as management directly associated with these functions.
- Network Control - includes all costs associated with network control (system operations). This includes functions such as planning and scheduling of switching activities, control room staff, management of field crews, dispatch operators, associated support staff, as well as management directly associated with these functions.
- Quality and Standard Functions - including standards & manuals, asset strategy (other than network planning), compliance, quality of supply, reliability, and network records (e.g. geographical information systems).
- Project Governance & Related Functions - includes all costs associated with the approval and management control of network projects or programs. This includes the cost of functions such as project management offices, works management, project accounting, or project control groups where these costs are not directly charged to specific projects or programs.
- Other network operating costs - including training, OH&S functions, training, network billing and customer service & call centre.

Capitalised overhead is overhead expenditure recognised as part of the cost of an asset, i.e. as capital expenditure.

Preparation Methodology:

Using information from the Financial System that was used to prepare the Annual Regulatory Accounts, Overheads Expenditure was classified into the prescribed categories in Table 2.10.1. In order to perform this allocation, expenditure information was extracted from the Financial System by cost ledger code and by division. Where there was a requirement to disaggregate the expenditure categories presented in the Annual Regulatory Accounts into the prescribed categories in Table 2.10.1, an assessment was made (by an appropriate expert) to determine the categorisations.

In Table 2.10.1, 'Overhead Expenditure before Allocation' (Standard Control Services, Negotiated Services and Unregulated Services) is presented on a gross basis (inclusive of amounts capitalised).

SPI Electricity capitalises Overhead expenditure that is directly attributable to bringing an asset to its intended in-service state. Indirect costs (to bring the asset to its intended in-service state) include labour costs of employees who do not complete timesheets. The amount of capitalised overheads was allocated to the prescribed categories based on the Activity Based Costing ("ABC") Survey process undertaken in accordance with the Cost Allocation Methodology. There has not been a material change in the capitalisation policy across the 2009 to 2013 Regulatory Years. Amounts capitalised have been separately presented under 'Capitalised Overheads' in Table 2.10.1.

Estimated Information:

The data included in Table 2.10.1 is considered estimated information as judgment was made to determine the categorisation of Network Overheads Expenditure. This is deemed Management's best estimate based on the data available.

Table 2.10.2 – Corporate Overheads Expenditure

Overhead expenditure in Table 2.10.2 has been reported before it is allocated to services or direct expenditure and before any part of it is capitalised.

Corporate Overhead Expenditure refers to the provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity. Corporate overhead costs include those for executive management, legal and secretariat, human resources, finance, bushfire and Royal Commission costs, Non-network IT support costs and regulatory costs.

Preparation Methodology:

Overheads Expenditure was classified into the prescribed categories in Table 2.10.2 using information used to prepare the Annual Regulatory Accounts (ultimately sourced from the Financial System). In order to perform this allocation, expenditure information was extracted from the Financial System by cost ledger code and by division. Where there was a requirement to disaggregate the expenditure categories presented in the Annual Regulatory Accounts into the prescribed categories in Table 2.10.2, an assessment was made, by an appropriate expert, to determine the categorisations.

In Table 2.10.2, Overhead Expenditure before Allocation (Standard Control Services, Negotiated Services and Unregulated Services) is presented on a gross basis (inclusive of amounts capitalised).

SPI Electricity capitalises overhead expenditure that is directly attributable to bringing an asset to its intended in-service state. These indirect costs (to bring the asset to its intended in-service state) include labour costs of employees who do not complete timesheets. The amount of capitalised overheads was allocated to the prescribed categories based on the ABC Survey process undertaken in accordance with the Cost Allocation Methodology. There has not been a material change in the capitalisation policy across the 2009 to 2013 Regulatory Years.

Amounts capitalised have been separately presented under 'Capitalised Overheads' in Table 2.10.2.

Estimated Information:

The data included in Table 2.10.2 is considered estimated information as judgment was made to determine the categorisation of Corporate Overheads Expenditure. This is deemed Management's best estimate based on the data available.

2.11 Labour

Labour costs reported relate only to costs incurred in the provision of standard control services (“SCS”). Costs have been allocated to SCS in accordance with the AER approved Cost Allocation Methodology in effect for the respective Regulatory Years.

Labour costs relating to labour hire contracts have been included within the classification levels. Labour used in the provision of contracts for both goods and services, other than contracts for the provision of labour (e.g. labour hire contracts) have not been reported.

Quantities of labour, expenditure, or stand down periods have not been reported multiple times across the labour categories. Where applicable, labour has been split between tables - for example, one worker may have half of their time allocated to corporate overheads and half of their time to network overheads.

The total cost of labour reported is equal to the total labour costs reported against the Capex and Opex categories listed in Template 2.10 Input Tables.

The following 3 categorisations have been applied -

1. Corporate Overhead costs - refer to the provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity.

2. Network Overhead costs - refer to the provision of management services and other related operational, network planning, asset management and compliance functions that cannot be directly associated with any specific operational activity.

3. Direct Network Labour - includes workers who primarily undertake field work in their job. This includes:
    - Field tradespeople including workers working in field depots (e.g. fitters and turners and mechanics working in depots).
    - Apprentices training for work that would primarily be field work (i.e. irrespective of whether most of their current work or training is not undertaken in the field).

The below definitions have been applied in the preparation of Tables 2.11.1 and 2.11.2.

Labour Classification Level	**Definition**
Executive manager	A manager responsible for managing multiple senior managers. For example CEO, General Manager People and Safety, Finance & Treasury and Legal. For the periods reported, Executive managers were

	employed by a related party entity The associated labour costs are reflected as a related party cost and are not a direct labour cost of SPI Electricity.
Senior Manager	A manager responsible for managing multiple managers who each manage work teams and projects within the organisation.
Manager	A manager responsible for managing teams of staff.
Professional	Professional workers who do not have a primary role as staff managers. These may include lawyers, accountants, economists etc.
Semi professional	Workers with some specialist training supporting fully trained professionals (e.g. draftsperson, bookkeeper etc).
Support staff	Non-professional support staff not undertaking field work (e.g. clerical support, secretaries).
Intern, junior staff, nonfield work apprentice	Interns, junior staff and apprentices undertaking non field work. All apprentices undertaking or training to undertake field work are reported under Labour Classification Level –Apprentice.
Skilled electrical worker	Fully qualified/trained electrical workers. This will include line workers, cable jointers, electrical technicians and electricians who have completed an apprenticeship.
Skilled non electrical worker	Skilled non electrical worker employed for their skill set. Examples are tradesmen who have completed an apprenticeship such as carpenters, mechanic, painters and arborists.
Apprentice	A field worker employed as part of a government accredited apprenticeship program. This includes all apprentices who will not primarily be working in offices once fully trained (e.g. apprentices training to become electrical workers, fitters and turners, plumbers, painters, mechanics and arborists).
Unskilled worker	Field workers with limited specialist training. This includes workers who have completed short courses with no other qualifications (e.g. labourer, arborist's assistant, traffic controller, meter reader).

Table 2.11.1 – Cost Metrics per Annum

For each Regulatory Year, a report was generated from the Payroll and Timesheeting Systems which provided information in relation to all employees required to submit timesheets and who charged time to Electricity Distribution business projects. The reports included details of labour costs, productive and non-productive hours, normal time/overtime/allowances and cost centre information. The yearly reports were compiled and, using data obtained from ABC surveys, scaled to reflect hours and costs relating to SCS work only. This compiled report is referred to hereafter as "Report 1".

A report was also generated from the Financial System (for all Regulatory Years) showing the labour hire employee costs. The report included a number of credit balances representing the allocation of labour hire costs to overheads when the relevant purchase order is receipted. To accurately reflect total labour hire costs, only debit entries were accounted for (before reallocations). Based on cost centres, the report was scaled to reflect standard control services costs only. This report is referred to hereafter as "Report 2".

For each Regulatory Year, a report was generated from the Payroll and Timesheeting Systems which provided information in relation to non-project related labour costs for the Distribution business. The reports included details of labour costs, productive and non-productive hours, normal time/overtime/allowances and cost centre information. The yearly reports were compiled and, using data obtained from ABC surveys, allocated into the Electricity Distribution and Gas Distribution businesses. The reports for the Electricity Distribution business were further scaled to reflect hours and costs relating to SCS work only. This compiled report is referred to hereafter as "Report 3".

SPI Electricity does not currently categorise employees in accordance with the prescribed categories.

Therefore using Reports 1 and 3, the appropriate labour categorisation levels were derived based on a combination of job titles, cost centres and the SP AusNet organisational chart. Judgments were made by an appropriate expert when determining the appropriate labour categorisation levels. This was performed using positions held for each employee and the date the positions changed, with the labour classification level being updated in the month in which the change occurred - for each Regulatory Year. The labour categorisation level was determined based on each employee's position and cost centre.

In relation to Report 2, labour hire resources were assigned to an appropriate labour classification level as well as a labour category based on the cost centres used to code the labour expenditure. For cost centres with various employee classifications, the labour classification level and labour category selected were based on the employee and labour category assigned to the majority of staff in that cost centre.

Based on judgments made, all data presented in Table 2.11.1 and 2.11.2 is considered estimated information. All information reported in these tables is considered Management's best estimate, based on the information available.

Average Staffing Level ("ASL")

One ASL is a full-time equivalent employee undertaking standard control services work receiving salary or wages over the entire year. For avoidance of doubt, a full time employee equating to one full-time equivalent ("FTE") over the course of the year that spends 50% of their time on standard control services work is 0.5 ASL.

FTEs include all active full-time and part-time, ongoing and non-ongoing employees engaged for a specified term or task who are paid through payroll (part-time employees are converted to full-time equivalent based on the hours they work) and workers engaged under labour hire contracts.

Preparation Methodology:

For Reports 1 and 3, the total SCS hours were divided by 1800 (reflecting the average annual hours worked - based on 48 weeks at 37.5 hours per week) to derive the number of ASLs.

For Report 2, the total cost was also divided by 1800 and by the average unit rate (per employee classification) to derive ASLs. The rates applied were the average of the standard hourly rates between 2011 and 2013 (based on employee classifications in the Payroll System). The calculated average was then applied to all Regulatory Years. One standard rate has been applied per employee classification.

Estimated Information:

For all FTEs, ASLs were derived using an estimation of the total annual hours worked. For labour hire employees and non-timesheet employees, further judgments were made in relation to the standard hourly rates used. Data provided is Management’s best estimate of the information required based on the information available.

Total Labour Cost

‘Total labour cost’ is the total labour costs associated with the total ASLs in a given classification level. Labour costs are the costs of Labour hire, Ordinary time earnings, Other earnings, on-costs and taxes and superannuation.

‘Ordinary time earnings’ means expenditure that was required under contracts of employment with SPI Electricity and which constitutes ordinary time salaries and wages. It excludes expenditure required under contracts other than employment contracts, irrespective of whether or not the contract includes a labour component.

Other earnings, on-costs, and taxes means expenditure:

- that was required under contracts of employment with SP AusNet; and
- which does not constitute employer superannuation contributions; and
- which constitutes:
  - overtime; and/or
  - staff allowances, including allowances for expenses incurred (e.g. meal allowances) and allowances for nature of work performed (e.g. special skills allowance, or living away from
  - home allowance); and/or
  - bonuses, incentive payments, and awards; and/or
  - benefits in kind and corresponding compensation payments (e.g. housing, electricity or gas subsidies); and/or
  - termination and redundancy payments; and/or
  - workers compensation; and/or
  - purchase of protective clothing for use by employees; and/or

- training and study assistance provided to employees; and/or
- taxes (payroll tax, fringe benefits etc)

Preparation Methodology:

Information reported in relation to 'Total labour costs' was obtained from Reports 1, 2 and 3, after SCS percentages were applied.

Given the requirement to reconcile Total Direct Labour Costs reported in Template 2.12 Input Tables to Template 2.11 Labour, an adjustment was made. The information contained in Reports 1, 2 and 3 were based on project data whereas the labour information in Template 2.12 was based on Payroll system data (which also had no labour hire data). The adjustment was calculated as the difference between these data sources and was allocated on a prorata basis to all employee classifications in Table 2.11.1.

Estimated Information:

Based on the above, the information provided is considered estimated information. Data provided is Management's best estimate of the information required based on the information available.

Average Productive Work Hours per ASL

Productive work hours are hours worked undertaken by the employee/labour hire person's substantive job. Productive work hours include:
- Supervised on the job training including supervision of apprentices, mentoring and normal employee feedback and development.
- All normal work involved in undertaking the person's substantive job including time spent on meetings and travel between different work areas.

Non-productive work hours are work hours that are non-productive such as annual leave, sick leave, training course and sessions (that are more than supervised on the job training, mentoring and normal employee feedback and development) and other non-productive work hours.

Preparation Methodology:

For Reports 1 and 3, information in relation to Productive work hours was included in the report data. 'Average Productive Work Hours per ASL' was calculated as Total Productive (SCS) hours divided by ASLs (engaged in SCS work).

For Report 2, 'Average Productive Work Hours per ASL' was calculated as the 'Total labour cost' divided by standard hourly rates and ASLs.

Estimated Information:

For labour hire employees , it has been assumed that all labour costs incurred relate to productive work only. Further assumptions were applied in relation to the standard hourly rates applied (as discussed above). Data provided is Management's best estimate of the information required based on the information available.

Stand Down Occurrences per ASL

Preparation Methodology:

'Stand down occurrences per ASL' is the average number of stand down periods per ASL in each labour classification level over the year.

A stand down period is where an employee, or worker employed under a labour hire contract, can't start a scheduled shift that would involve standard control services work at normal ordinary time wages due to prior work at the organisation (for example, due to not having sufficient time off between work shifts).

Data reported was obtained from the Payroll and Timesheeting Systems based on hours recorded against a stand down time code. Data was available for all Regulatory Year and is considered actual information.

Table 2.11.2 – Extra Descriptor Metrics for Current Year

Average Productive Work Hours per ASL – Ordinary Time

'Average Productive Work Hours per ASL – Ordinary Time' is the average productive work hours per regulatory year per ASL in each classification level spent on standard control services work that are 'Ordinary time earnings'.

Preparation Methodology:

For Reports 1 and 3, information in relation to normal (ordinary) time is available. 'Average productive work hours per ASL – ordinary time' was calculated as total normal time divided by ASLs.

For labour hire employees included on Report 2, 'Average productive work hours per ASL – ordinary time' was calculated as 'Total labour cost' divided by the standard rates.

Estimated Information:

For labour hire employees, it has been assumed that labour costs incurred relate to ordinary time only. Further assumptions were applied in relation to the standard hourly rates used (as discussed previously above). Data provided is Management's best estimate of the information required based on the data available.

Average Productive Work Hours Hourly Rate per ASL – Ordinary Time

'Average Productive Work Hours Hourly Rate per ASL – Ordinary Time' is the Regulatory Year's average productive work hours (spent on standard control services) hourly rate per ASL for each Classification level including labour costs that are direct on costs related to 'Ordinary time earnings'.

The average hourly rate for each year is calculated by reference to the average number of hours paid as 'Ordinary time earnings' for each year and includes costs that are ordinary time salaries and wages in the year.

Preparation Methodology:

For Reports 1 and 3, this metric was calculated as the productive, normal labour cost divided by productive normal hours. This was then reduced by an estimated percentage of on-costs. The on-cost percentage used was the 2013 percentage applicable to Victorian employees (where the majority of employees are based). The percentage applied was obtained from the Payroll System.

For Report 2, this metric was calculated as the 'Total Labour cost' divided by average productive hours. This was then reduced by the percentage of on-costs (as discussed above).

Estimated Information:

The on-cost percentage applied was estimated based on payroll information for Victorian employees. One standard percentage has been applied across all SPI Electricity employees. This is considered Management's best estimate based on the data available.

Average Productive Work Hours per ASL – Overtime

'Average productive work hours per ASL – Overtime' is the average overtime hours for the regulatory year paid per ASL for each classification level per year spent on standard control services. Overtime hours are paid productive work hours that are not 'Ordinary time earnings'.

Preparation Methodology:

For Reports 1 and 3, information in relation to overtime is available. The 'Average productive work hours per ASL – overtime' was calculated as total productive overtime hours divided by ASLs.

For Report 2 all labour hire employees' and non-timesheet employees' time is considered ordinary time. Based on this, no 'Average productive hours per ASL – Overtime' calculation was performed.

Estimated Information:

For labour hire employees included in Report 2, it has been assumed that all labour costs incurred relate to ordinary time only. This is considered Management's best estimate based on the data available.

Average Productive Work Hours Hourly Rate per ASL – Overtime

'Average Productive Work Hours Hourly Rate per ASL' is the Regulatory Year's average productive work hours (spent on standard control services) hourly rate per ASL for each classification level including labour costs that are direct on costs related to productive overtime hours that are not 'Labour Costs – ordinary time earnings'.

The average hourly rate is calculated by reference to the average number of productive work hours paid as overtime and includes costs that are overtime salaries and wages in the year.

Preparation Methodology:

For Reports 1 and 3, this metric was calculated as the productive, overtime labour cost divided by the productive overtime hours. This was then reduced by the 2013 on-cost percentage of on-costs for Victorian employees. The percentage used was extracted from the Payroll System.

For Report 2 all labour hire employees' time is considered ordinary time. Based on this, no 'Average Productive Work Hours Hourly Rate per ASL – Overtime' calculation was performed.

Estimated Information:

The on-cost percentage applied was estimated based on payroll information for Victorian employees. One standard percentage has been applied across all SPI Electricity employees.

For labour hire employees and non-timesheet employees (included in Report 2), it has been assumed that all labour costs incurred relate to ordinary time only.

The information provided is Management's best estimate based on the data available.

2.12 Input tables

Information reported in Template 2.12 Input Tables relates to direct costs for Standard Control and Alternative Services. Data reported excludes overheads and is presented on an 'as incurred' basis. The cost allocations presented (Direct Materials Cost, Direct Labour Cost, Contract Cost, Other Cost, Related Party Contract Cost and Related Party Contract Margin) are considered mutually exclusive.

The summation of costs for each category reconcile to total expenditure amounts reported in each of the respective templates.

Direct Costs

Preparation Methodology:

Vegetation Management

For all Regulatory Years, information was sourced from the Financial System. A direct costing report was run based on work codes which provided a split of costs into Direct Materials, Direct Labour, Contract Costs and Other. Work codes do not directly align with the costs included in Template 2.7 Vegetation Management. Based on this, the report generated was used as a proxy for the information required and was proportionately scaled to align with the total Vegetation Management costs reported. This process was followed for each Regulatory Year.

The total Direct Materials, Direct Labour, Contract Costs and Other costs was split between HBRA and LBRA in each Regulatory Year based on the proportion of total costs in Template 2.7 Vegetation Management allocated to HBRA and LBRA.

Routine and Non-Routine Maintenance

For all Regulatory Years, information was sourced from the Financial System. A report was generated which allocated the costs reported in Template 2.7 Maintenance into the cost categories required. This process was completed for each Regulatory Year.

Overheads

For all Regulatory Years, information was sourced from the Financial System and prior year Annual Regulatory Accounts working files. A report was generated which allocated the costs reported in Template 2.8 Overheads into the cost categories required. This process was completed for each Regulatory Year.

Augmentation

For all Regulatory Years, a report was generated from the Financial System which provided the cost category breakdown required (at a total Augex level). To populate Template 2.12 Input Tables, this report was required to be allocated into the prescribed asset categories. The percentage of costs incurred for each asset category in each Regulatory Year was calculated based on information reported in Table 2.3.4 in Template 2.3 Augex. This percentage was applied to the total cost category report to derive an estimate of the data required.

Connections

For all Regulatory Years, information was sourced from the Financial System. A report was generated which allocated the work codes reported in Template 2.5 Connections into the cost categories required. This process was completed for each Regulatory Year.

A report was unable to be generated from the Financial System for a portion of the costs reported in Template 2.5 Connections as they could not be directly associated with one work code. For these costs, the allocation into Direct Materials, Direct Labour, Contract Costs and Other Costs was determined based on a percentage allocation method using the work code report generated for the other portion of Connection expenditure.

Emergency Response

For all Regulatory Years, information was sourced from the Financial System. A report was generated by the cost categories required for the Emergency Response work codes. As noted in section 2.9 above, a suitable expert reviewed the data by work codes to determine the percentage to be allocated to Emergency Response. This process was completed for each Regulatory Year. The data reported in Template 2.12 Input Tables agrees to the total Emergency Response expenditure reported in Template 2.9 Emergency Response.

Public Lighting

For all Regulatory Years, information was sourced from the Financial System. A report was generated which allocated the costs reported in Template 4.1 Public Lighting into the cost categories required. This process was completed for each Regulatory Year.

Metering

In relation to Metering Capex, information was sourced from the Financial System and working files of the Annual Regulatory Accounts. A report was generated which allocated metering project costs into the required cost categories (direct materials, direct labour, contracts and other). The percentage allocation of the project costs into the cost categories was applied to total metering Capex.

In relation to Metering Opex, information was sourced from the Financial System. A report was generated which allocated the majority of Opex costs reported in Template 4.2 Metering into the cost categories required. This process was completed for each Regulatory Year. A portion of the Metering Opex costs could not be directly aligned with a system report. For these costs, the judgment of a SME was applied to determine the split of the costs into Direct Materials, Direct Labour, Contract Costs and Other Costs.

Fee-based Services

For all Regulatory Years information was sourced from the Financial System. The costs reported in Template 4.3 Fee-based Services were unable to be directly allocated into the required cost categories (Direct Materials, Direct Labour, Contract Costs and Other Costs) due to system limitations. Based on this, a related work code was identified and a report was generated in the system which allocated the work code costs into the required cost categories. The percentage allocation of these costs was calculated and applied to the total costs reported in Template 4.3 Fee-based Services to derive an estimate of the required cost category allocations. This process was completed for each Regulatory Year. The work code used was considered a reasonable proxy for the information needed.

Quoted Services

For the 2012 and 2013 Regulatory Years, information was sourced from the Financial System. The costs reported in Template 4.4 Quoted Services were unable to be directly allocated into the required cost categories (Direct Materials, Direct Labour, Contract Costs and Other Costs) due to system limitations. Based on this, a related work code (which is considered a reasonable proxy) was identified and a system report was generated which allocated the work code costs into the required cost categories. The percentage allocation of these costs was calculated and applied to the total costs reported in Template 4.4 Quoted Services in the 2012 and 2013 Regulatory Years to derive an estimate of the required cost category allocations.

For the 2009 to 2011 Regulatory Years, the average percentage allocation of costs (into Direct Materials, Direct Labour, Contract Costs and Other Costs) for the 2012 and 2013 Regulatory Years was calculated. These percentages were applied to the total Quoted Services costs in the 2009 to 2011 Regulatory Years to derive an estimate of the required cost category allocations.

Replacement

For all Regulatory Years, the required information was extracted from the Financial System for direct costs only. Reports were run from the Financial System on an 'as incurred' basis and provided the total cost categories for each Regulatory Year.

The allocation of the total costs into the Repex asset group categories was determined based on the percentage allocation of costs in Template 2.1 Repex. This process was completed for each Regulatory Year.

Non-Network Expenditure

For all Regulatory Years, information was sourced from the Financial System and from workings to the Annual Regulatory Accounts and Template 2.5 Non-Network.

The allocation of Motor Vehicle Capex into the cost categories is considered estimated information as it was assumed that all Capex costs are based on contracts with third party suppliers, hence classified as Contract Costs.

Estimated Information:

Data provided for Vegetation Management is considered estimated information as the system generated report was used as a proxy for the information required and was proportionately scaled to provide the information required. An allocation of costs was also made to split between HBRA and LBRA.

The Routine and Non-Routine Maintenance information is estimated information based on judgments made to allocate expenditure between Routine and Non-Routine Maintenance in Template 2.7 Maintenance.

The Emergency Response and Overheads information is considered estimated information due to the judgment made to categorise some of the data.

The information provided for all Regulatory Years in relation to Augmentation, Connections, Metering, Fee-based Services, Quoted Services and Replacement is considered estimated information due to the percentage allocation applied to categorise the data.

Information provided in relation to Motor Vehicles is considered estimated information as Motor Vehicle Capex was estimated to be Contract costs only. This is considered reasonable based on the nature of Motor Vehicles Capex.

The information provided is considered Management's best estimate, based on the data available.

Related Party Costs and Margin

Preparation Methodology:

For the purpose of completing Template 2.12 Input Tables, a 'Related Party Contract' is defined as a finalised contract between SPI Electricity and a Related Party for the provision of goods and/or Services. A Related Party is defined as any other entity that:

(a) had, has or is expected to have control or significant influence over SPI Electricity;
(b) was, is or is expected to be subject to control or significant influence from SPI Electricity;
(c) was, is or is expected to be controlled by the same entity that controlled, controls or is expect to control SPI Electricity – referred to as a situation in which entities are subject to common control;
(d) was, is or is expected to be controlled by the same entity that significantly influenced, influences or is expected to influence SPI Electricity; or
(e) was, is or is expected to be significantly influenced by the same entity that controlled, controls or is expected to control SPI Electricity;

but excludes any other entity that would otherwise be related solely due to normal dealings of:

(a) financial institutions;
(b) authorised trustee corporations as prescribed in Schedule 9 of the Corporations Regulations 2001 (Cth);
(c) fund managers;
(d) trade unions;
(e) statutory authorities;
(f) government departments;
(g) local governments and includes SPI Electricity Pty Ltd; or
(h) where any of the entities identified in sub-paragraphs (a) to (e) have novated or assigned a contract or arrangement to or from another entity (where that contract or arrangement relates to the provision of electricity distribution services by SP AusNet), the entity to whom that contract or arrangement has been novated or assigned.

Related Party Costs (both Opex and Capex) were obtained from the Annual Regulatory Accounts for each Regulatory Year. Using the workings to the Annual Regulatory Accounts, Related Party Costs were allocated into the categories required by a SME. The allocation was based on the nature of the expenses and the counterparty.

In relation to Augmentation and Replacement, the Related Party Costs were allocated across the various Augmentation and Replacement sub-categories based on the percentage allocations applied to the total direct costs.

Related Party Margins have been estimated based on an analysis of contracts currently in place with Related Parties. The judgments and resulting estimates were made by an appropriate SME.

Estimated Information:

The allocation of Related Party costs for the Augmentation and Replacement sub-categories was estimated using the same percentage applied to allocate the direct costs. All Related Party Margin information provided is considered estimated information due to the judgments made in relation to counter party margins. The information provided is considered Management's best estimate, based on the data available.

4.1 Public lighting

Public lighting information relates to non-contestable, regulated public lighting services only and excludes contestable services and negotiated public lighting services.

Table 4.1.1 – Descriptor Metrics over Current Year

Information contained in the Asset Management Systems as well as the Fixed Asset Register does not distinguish between gifted assets and non-gifted assets. Based on this, the data reported is an estimate of the non-gifted asset information required.

Preparation Methodology:

Information in relation to the 'Current Population of Lights' was obtained from the SDME Asset Management System. System reports as at 26 December 2013 and as at 27 December 2012 were generated providing total light quantities by watts and light type. Based on the knowledge of an SME, the year on year movement in lights is considered to represent gifted assets (e.g. the annual growth in light population is attributable to gifted assets only). On this basis, the 'Current Population of Lights' as at 27 December 2012 is deemed to provide a reasonable estimate of the non-gifted light population as at 31 December 2013.

Estimated Information:

This is considered Management's best estimate of the data required based on the information available.

Table 4.1.2 – Descriptor Metrics Annually

Gross public lighting expenditure (before subtracting customer contributions) has been reported, on an 'as incurred' basis, in nominal terms. Work performed by third parties on behalf of SPI Electricity has been included in the metrics reported. Expenditure on public lighting has not been distinguished between standard and alternative control services in this template.

Light Installation – Volume of Works and Expenditure

Light Installation is an installation on a major or minor road for the purpose of establishing new luminaires, including associated components such as bracket and lamp. The installation may also include poles dedicated to public lighting services and underground or overhead cabling dedicated to public lighting services.

Preparation Methodology:

The total of 'Major Road Light Installation Volume' and 'Minor Road Light Installation Volume' was obtained from the AER Economic Benchmarking Report (as the yearly movement in 'Public Lighting

Luminaries'). This information was available for all Regulatory Years. Data reported was ultimately sourced from the AMFM/GIS spatial mapping system.

The Economic Benchmarking data included both gifted and non-gifted assets. To derive an estimate of the volumes of non-gifted assets, an analysis of the 2013 Regulatory Year public lighting installation costs was performed. The percentage of direct costs without customer contributions as a proportion of total installation costs was calculated. This percentage was applied to the total volumes to estimate non-gifted light installations.

For the 2011 to 2013 Regulatory Years, an AMFM/GIS report provided a split of light volumes into Major Road and Minor Road categories. For the 2009 and 2010 Regulatory Years, information in relation to the category split was unavailable. This split was estimated using the ratio of Major and Minor Road Volumes from a luminaries report from the AMFM/GIS system for these years.

'Number of Poles Installed' was obtained from the AER Economic Benchmarking Report as the yearly movement in 'Public lighting poles'. The underlying data was extracted directly from the AMFM spatial mapping system for the 2013 Regulatory Year. For the 2009 to 2011 Regulatory Years, reliable system data was not available. This information was estimated using the 2013 and 2012 data reduced by the annual change of public lighting luminaires multiplied by an average percentage of luminaries to poles.

The Economic Benchmarking data included both gifted and non-gifted assets. To derive an estimate of the volumes of non-gifted assets, an analysis of the 2013 Regulatory Year public lighting installation costs was performed. The percentage of direct costs without customer contributions as a proportion of total installation costs was calculated. This percentage was applied to the total volumes to estimate non-gifted light installations.

'Total Cost' was sourced from information in the Financial System. A report was generated from the system for each Regulatory Year, using the relevant Public Lighting work code. Costs reported are direct costs only (gross of capital contributions) and are on an 'as incurred' basis.

<u>Estimated Information:</u>

Installation volumes provided is considered estimated information due to the assumptions applied in excluding gifted assets. Assumptions were applied in relation to Major and Minor Road Light Installation Volumes in the 2009 and 2010 Regulatory Years due to the ratios applied to derive the Major Road and Minor Road splits. Additionally, the 'Number of Poles Installed' was estimated for the 2009 to 2011 Regulatory Years due to the lack of reliable system data.

The information provided is considered Management's best estimate of public lighting pole numbers based on the information available.

Light Replacement - Volume of Works and Expenditure

Preparation Methodology:

The ‘Major Road Light Installation Volume’ and ‘Minor Road Light Installation Volume’ (for Light Replacement) data for the 2012 and 2013 Regulatory Years was obtained from an internal report. This report was compiled using information obtained from the external contractor who manages SPI Electricity’s Public Lighting assets.

For the 2011 Regulatory Year, the above mentioned report was available for 9 months only. The total of the report for 9 months was extrapolated over 12 months to provide an estimate of the required data.

For the 2009 and 2010 Regulatory Years, the data required was estimated. For the 2009 and 2010 Regulatory Years, the data required was estimated. The volume to cost ratio for the 2012 and 2013 Regulatory Years was applied to the 2010 Regulatory Year costs to derive an estimate of the 2010 volumes. The same approach was applied to the 2009 Regulatory Year.

The average percentage split between Major and Minor Roads in the 2012 and 2013 Regulatory Years was calculated and applied to the total volumes for the 2009 and 2010 Regulatory Years to derive an estimate of the Major Road and Minor Road allocation.

The ‘Number of Poles Installed’ was obtained from a report generated in the Workbench Scheduling System. The raw data report was subject to analysis by an appropriate SME to ensure the relevant data was obtained. Based on this process, the data provided is considered estimated information. This report generated in Workbench was available for the 2012 and 2013 Regulatory Years and the same process was followed for these years.

For the 2009 to 2011 Regulatory Years, the ‘Number of Poles Installed’ was estimated using the average of poles installed as a percentage of poles installed and replaced in the 2012 and 2013 Regulatory Years.

‘Total Cost’ was sourced from information in the Financial System. A report was generated for each Regulatory Year, using the relevant Public Lighting work code. Costs reported are direct costs only and are on an ‘as incurred’ basis.

Estimated Information:

The ‘Major Road Light Installation Volume’, ‘Minor Road Light Installation Volume’ and ‘Number of Poles Installed’ was estimated for the 2009 to 2011 Regulatory Years. This was required as actual, reliable system data was unavailable.

The estimates provided are considered Management’s best estimate, based on the information available.

Light Maintenance - Volume of Works and Expenditure

Preparation Methodology:

The 'Major Road Light Installation Volume' and 'Minor Road Light Installation Volume' – Light Maintenance data for the 2012 and 2013 Regulatory Years was obtained from an internal report. This report was compiled using information obtained from the external contractor who manages SPI Electricity's Public Lighting assets.

For the 2011 Regulatory Year, the above mentioned report was available for 9 months only. The total of the report for 9 months was extrapolated over 12 months to provide an estimate of the required data.

For the 2009 and 2010 Regulatory Years, the data required was estimated. The volume to cost ratio for the 2012 and 2013 Regulatory Years was applied to the 2010 Regulatory Year costs to derive an estimate of the 2010 volumes. The same approach was applied to the 2009 Regulatory Year. The average percentage split between Major and Minor Roads in the 2012 and 2013 Regulatory Years was calculated and applied to the total volumes for the 2009 and 2010 Regulatory Years to derive an estimate of the Major Road and Minor Road allocation.

The 'Number of Poles Installed' has been reported as zero as poles are not installed or replaced under maintenance works.

'Total Cost' was obtained from the Financial System for each Regulatory Year on a work code basis. Costs reported are direct costs only and are on an 'as incurred' basis.

Estimated Information:

The 'Major Road Light Installation Volume' and 'Minor Road Light Installation Volume' was estimated for the 2009 to 2011 Regulatory Years. This was required as actual, reliable data was unavailable.

The estimates provided are considered Management's best estimate, based on the information available.

Quality of Supply

Preparation Methodology:

'Mean days to Rectify/Replace Public Lighting Assets' was obtained from data reported in the Annual Regulatory Accounts (Non-Financial RIN) for the 2011 to 2013 Regulatory Years. For the 2009 to 2010 Regulatory Years, information was obtained from the PowerOn System.

The 'Volume of GSL Breaches' and 'GSL Payments' was obtained from the PowerOn System for all Regulatory Years. In relation to GSLs, data has not been reported where a GSL scheme does not exist for a public lighting service.

Data in relation to the 'Volume of Customer Complaints' was obtained from a report generated in the Issues Management System (IMS) for each Regulatory Year. A customer complaint is considered a written or verbal expression of dissatisfaction about an action, or failure to act, or in respect of a product or service offered or provided by an electricity network distributor.

All information provided is considered Actual Information as no estimates were required.

Table 4.1.3 – Cost Metrics

Preparation Methodology:

Information reported in relation to the 'Average Unit Cost for Public Lighting Services' was based on data obtained from contract rate schedules. These rate schedules were available for the 2011 to 2013 Financial Years and provided the unit rates of light types for each region in SPI Electricity's distribution network. These rates were used as an estimate of the rates by light type for the 2011 to 2013 Regulatory Years. This is considered the best available information based on the data required.

For Major Lights, the average rate per light across the 3 regions in SPI Electricity's distirbution network was calculated and assumed to be consistent across all major light types.

For Minor lights, contract rate data was available for 3 light types. The average contract rate across the 3 regions for each of these 3 light types was calculated. Table 4.1.3 was populated by estimating the alignment of the 3 light types into the prescribed light type categories. For the remaining Minor light types in which contract rate data was not available, the average contract rate of the 3 Minor light types was used as proxy.

For the 2009 to 2010 Regulatory Years, the 'Average Unit Cost' was estimated using the average of the unit cost per the contract rate schedules in the 2011 to 2013 Regulatory Years. These unit costs were de-escalated over the2009 and 2010 Regulatory Years based on the average annual increase in the unit cost across these years.

Estimated Information:

All 'Average Unit Cost' metrics are considered estimated information. Data provided is considered Management's best estimate, based on the information available.

4.2 Metering

Data reported relates to non-contestable, regulated metering services only. This includes work performed by third parties on behalf of SPI Electricity. Data in relation to contestable metering services has not been provided.

Meter type 4 is defined as a remotely read interval meter with communications functionality that is:

- designed to transmit metering data to a remote location for data collection; and
- does not, at any time, require the presence of a person at, or near, the meter for the purposes of data collection or data verification (whether this occurs manually as a walk-by reading or through the use of a vehicle as a close proximity drive-by reading), including, but not limited to, an interval meter that transmits metering data via direct dialup, satellite, the internet, general packet radio service, power line carrier, or any other equivalent technology.

Meter type 4 includes metering assets and services introduced with the Advanced Metering Infrastructure (“AMI”) rollout.
Meter type 5 is defined as a manually read interval meter that records interval energy data, which is not a remotely read interval meter.
Meter type 6 is defined as a manually read accumulation meter which measures and records electrical energy in periods in excess of a trading interval.

Table 4.2.1 – Metering Descriptor Metric

Preparation Methodology:

Information was sourced from the Annual Regulatory Accounts for each Regulatory Year (which was ultimately obtained from SAP).

Data from the Annual Regulatory Accounts was classified into the prescribed categories in Table 4.2.1. For the 2009 to 2013 Regulatory Years, in the Meter Volume Schedules in the Annual Regulatory Accounts, ‘Current Transformer Connected’ meters have been categorised as ‘Current Transformer Connected Meter Population’. All other meters are classified ‘direct connected’ per the categorisations in Table 4.2.1.

Estimated Information:

For the 2009 to 2010 Regulatory Years, in the Meter Volume Schedules in the Annual Regulatory Accounts, all AMI meters (Type 4) and Accumulation Meters (Type 6) are assumed to be ‘single phase’ and ‘direct connected’ per the categorisations in Table 4.2.1. This information has been estimated as the allocation within this meter type is not available.

The data provided is considered Management’s best estimate based on the information available.

Table 4.2.2 – Cost Metrics (Volume)

Preparation Methodology:

For the Meter Purchase, New Meter Installations, Meter Replacement and Remote Meter Reading metrics, volume data was obtained from the financial information in the workings to the Annual Regulatory Accounts (which was ultimately sourced from information contained in SAP and the previous meter management CIS System).

In relation to the Scheduled Meter Readings, Special Meter Reading, Meter Maintenance, Scheduled Meter Testing and Meter Investigations metrics, information was obtained from reports generated in the SAP, PowerOn and Evolution systems. The total volumes of meters were known in the above categories; however the allocation between meter types was required to be estimated for the meter volumes relating to Scheduled Meter Testing, Meter Investigation, Meter Maintenance, Scheduled Meter Reading (the 2009 and 2010 Regulatory Years only) and Special Meter Reading. This estimation was performed based on the overall percentage of type 4, 5 and 6 meter volumes.

Estimated Information:

The volume information provided in relation to Scheduled Meter Testing, Meter Investigation, Meter Maintenance, Scheduled Meter Reading (the 2009 and 2010 Regulatory Years only) and Special Meter Reading is considered estimated information based on the methodology applied to derive the required information. Data provided is considered Management's best estimate, based on the information available.

Table 4.2.2 – Cost Metrics (Expenditure)

Preparation Methodology:

In relation to Meter Opex, the total expenditure and the cost per meter type was determined for each of the required service subcategories (based on the process outlined below). Using this information, an estimate of the expenditure by meter type was derived.

Meter Operating Expenditure - Total Cost Calculations:

Meter Testing

Total Costs: Total Costs were calculated as the sum of Field Services Costs and Back Office Costs. An analysis was conducted of data obtained from the Financial System to estimate Field Services Costs. An estimate of Back Office Costs was calculated based on scheduled testing volumes multiplied by the 'cost per test'. 'Cost per test' was calculated using total costs per the Financial System data divided by the sum of scheduled and unscheduled testing volumes. Volume information was obtained from SAP.

Meter Maintenance

Total Costs: An analysis of Field Service Cost data extracted from the Financial System was performed to derive an estimate of total Meter Maintenance costs.

Meter Investigations

Total Costs: Total Costs were calculated as the sum of Field Services Costs, Revenue Protection Costs and Back Office Costs. An analysis of data extracted from the Financial System was performed to derive an estimate of field service and revenue protection costs. An estimate of Back Office Costs was calculated based on unscheduled testing volumes multiplied by the 'cost per test'. 'Cost per test' was calculated using total costings per the Financial System data divided by scheduled and unscheduled testing volumes. Volume information was obtained from SAP.

Meter Testing

Total Costs: An analysis of cost data extracted from the Financial System was performed to calculate total meter testing costs.

Remote Meter Reading

Total Costs: An analysis of cost data extracted from the Financial System was performed to calculate total remote meter reading costs.

Scheduled Meter Reading

Total Costs: An analysis of cost data extracted from the Financial System was performed to calculate total special meter reading costs.

Special Meter Reading

Total Costs: An analysis of cost data extracted from the Financial System was performed to calculate total special meter reading costs.

Meter Operating Expenditure - Costs per Meter Type:

To derive expenditure by meter type, estimated allocations were performed.

Total Meters:

For the 2009 and 2010 Regulatory Years, total meter reading volumes were divided by 4 to estimate total meters. It was assumed that all meters are read 4 times a year. For these regulatory years, it has been assumed that all meters are Meter Type 6.

For the 2011 to 2013 Regulatory Years, the increase in total meters between the 2009 and 2010 Regulatory Years was calculated and this increase was applied to the 2011 to 2013 Regulatory Years to estimate total meters in these years.

Scheduled meter reading volumes were used to derive percentage estimates of the meter type splits. Where no splits were available between Meter Type 5 and Meter Type 6, it has been assumed that all meters are accumulated, not interval meters. The calculated percentage splits were applied to the total costs of the relevant categories.

Other Metering Opex

Other Metering relates to other Opex costs associated with metering which are not separately disclosed in Table 4.2.2. This includes costs for activities in scope as per the AMI Order in Council including program management costs and support costs. As such these costs have been reported against Meter Type 4 and are considered 'actual information' as no estimates were required. Costs were sourced from the workings to the Annual Regulatory Accounts (based on information obtained from the Financial System).

IT Infrastructure Opex

IT Infrastructure Opex relates to costs associated with the AMI rollout. Costs were sourced from the workings to the Annual Regulatory Accounts (based on information obtained from the Financial System).

Communications Infrastructure Opex

Communications Infrastructure Opex relates to costs associated with the AMI rollout. Costs were sourced from the workings to the Annual Regulatory Accounts (based on information obtained from the Financial System).

<u>Estimated Information – Operating Expenditure:</u>

The total costs in relation to Remote Meter Reading, Scheduled Meter Reading and Special Meter Reading is considered actual information. However the derived allocation of these costs into the prescribed meter types results in the information provided being estimated information.

The total costs of Meter Testing, Meter Maintenance and Meter Investigations is considered estimated information based on the data preparation methodology outlined above.

The information provided is considered Management's best estimate of the data required, based on the information available.

Meter Capital Expenditure:

Preparation Methodology:

In relation to Meter Capex, the total expenditure and the cost per meter type was determined for each of the required service subcategories (based on the process outlined below). Using this information, an estimate of the expenditure by meter type was derived.

Meter Purchase

Meter purchase relates to the direct material cost of purchasing the meter for installation or replacement. This includes the cost of delivery to SPI Electricity's store, including testing of equipment and inclusion of spare parts. All meters purchased were in relation to meter type 4. For the 2010 to 2013 Regulatory Years, cost of meters was separately identifiable from installation costs from the Financial System.

In the 2009 Regulatory Year, installation costs were not separately identifiable form meter costs in the Financial System. To obtain meter cost for the 2009 Regulatory Year, the average meter cost between the 2010 to 2013 Regulatory Years was used as a proxy and multiplied by the volume of meter type 4 purchased in the 2009 Regulatory Year.

New Meter Installation

To derive the installation cost of a new meter installation by meter type, the total installation costs in the 2010 to 2013 Regulatory Years (obtained from the Financial System) was equally proportioned across the volume of new meters installed and meters replaced in the 2010 to 2013 Regulatory Years.

In the 2009 Regulatory Year, an adjustment was made to total meter installation cost to include a portion of installation cost which was recorded as part of meter purchase cost (refer to discussion in Meter Purchase above). This adjusted total meter installation cost was then applied proportionately to both the volume of new meters installed and meters replaced in the 2009 Regulatory Year.

Meter Replacement

Meter replacement relates to the replacement cost of a meter and associated equipment at a site with existing metering infrastructure. Meter replacement only includes the installation cost to replace an existing meter as the cost of the replacement meter is disclosed under Meter Purchase. As noted above, the installation costs for a new meter cannot be distinguished from a replacement meter in the Financial System. As installation costs do not significantly vary by meter types, but rather by the location of the meter installation within SPI Electricity's distribution network, it has been assumed that the installation cost is the same across all meter types. To derive the installation cost of a meter replacement by meter type, the total installation costs in the 2010 to 2013 Regulatory Years (obtained from the Financial System) was equally proportioned across the volume of new meters installed and meters replaced in the 2010 to 2013 Regulatory Years.

In the 2009 Regulatory Year, an adjustment was made to total meter installation cost to include a portion of installation cost which was recorded as part of meter purchase cost (refer to discussion in Meter Purchase above). This adjusted total meter installation cost was then applied proportionately to both the volume of new meters installed and meters replaced in the 2009 Regulatory Year.

IT Infrastructure Capex

IT Infrastructure Capex relates to costs associated with the AMI rollout. Costs were sourced from the workings to the Annual Regulatory Accounts (based on information obtained from the Financial System).

Communications Infrastructure Capex

Communications Infrastructure Capex relates to costs associated with the AMI rollout. Costs were sourced from the workings to the Annual Regulatory Accounts (based on information obtained from the Financial System).

Estimated Information – Capital Expenditure:

Information provided in relation to New Meter Installation costs (in the 2009 Regulatory Year), New Meter Installation costs (all Regulatory Years) and Meter Replacement costs (all Regulatory Years) is considered estimated information.

4.3 Fee-based Services

Expenditure on Fee-based Services has not been distinguished between standard and alternative control service or between Capex and Opex. Direct costs (excluding overheads) have been reported in nominal terms and are presented on an 'as incurred' basis.

Table 4.3.1 – Cost Metrics for Fee-based Services

Preparation Methodology:

For each Regulatory Year, the financial information was sourced from the workings to the Annual Regulatory Accounts.

Information in relation to the volumes and revenues (used as a proxy for costs) of Field Officer Visits, New Connections, Service Truck Visits and Meter Equipment Tests was calculated using billing information (contained in the workings to the Annual Regulatory Accounts). The reported data was derived by calculating the number of sales invoices and other sales transactions for each of the above fee-based categories in each Regulatory Year. It has been assumed that one sales invoice/transaction is equal to one fee-based service volume and cost.

The volume of Meter Conversions has been estimated as the number of solar installations in each Regulatory Year. Information in relation to solar installations was obtained from the SAP system, which is the main inventory and customer management system. It has been assumed that all Meter Conversions relate to solar installations. This is considered a reasonable assumption given that solar panel installations by customers are the main driver for meter conversions.

The volume of Embedded Generator fee-based services was estimated as the total number of sales invoices included in the relevant general ledger account in the Financial System and the number of other manual/ad hoc invoices included in the Embedded Generator fee calculations in the Annual Regulatory Account workings. It has been assumed that one sales invoice/transaction is equal to one fee-based service volume.

Estimated Information:

The non-financial information presented in Table 4.3.1 is considered estimated information based on the preparation approach outlined above. This is considered Management's best estimate of the required data based on the information available.

4.4 Quoted Services

Expenditure on Quoted Services has not been distinguished between standard and alternative control services or between Capex and Opex. Direct costs (excluding overheads) have been reported in nominal terms and are presented on an 'as incurred' basis.

Table 4.4.1 – Cost Metrics for Quoted Services

Preparation Methodology:

For each Regulatory Year, the financial information was sourced directly from the workings to the Annual Regulatory Accounts.

Information in relation to volumes and revenues (used as a proxy for cost) of quoted services was obtained from the workings to the Annual Regulatory Accounts (based on information sourced from the Financial System). The reported data was derived by calculating the number of sales invoices and other sales transactions for recoverable works in each Regulatory Year. It has been assumed that one sales invoice/transaction is equal to one quoted service volume and cost.

Estimated Information:

The non-financial information presented in Table 4.4.1 is considered estimated information based on the preparation approach outlined above. This is considered Management's best estimate of the required data based on the information available.

5.2 Asset age profile

The age profile for assets currently in commission has been provided for each prescribed asset category. Data reported corresponds with the 5 years of historical replacement volumes and cost data in Template 2.2 Repex.

Economic life is the estimated period after installation of the new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. The period of effective service considers the life cycle costs between keeping the asset in commission and replacing it with its modern equivalent. Life cycle costs of the asset include those associated with the design, implementation, operations, maintenance, renewal and rehabilitation, depreciation and cost of finance.

'Installed assets – quantity currently in commission by year' is the number of assets currently in commission and the year they were installed.

Table 5.2.1 – Asset Age Profile

Preparation Methodology:

Information was sourced from the Asset Management Systems. The information extracted from the Asset Management Systems is current data as at May 2014. This is due to the Asset Management Systems being 'live' databases. System limitations prevent asset reports being run as at specific (historic) points in time. Additionally, it is noted that the Asset Management system data has been subject to data cleansing over the Regulatory Years and is subject to continuing reviews.

The SPI Electricity asset categories do not directly align with the prescribed AER asset categories. In order to populate Table 5.2.1, engineering judgment has been applied to align assets in the required categorisations. Where SPI Electricity identified assets that are significantly different to the asset categories prescribed by AER, 'Other' categories have been included in Table 5.2.1 with a suitable description.

The quantity of assets included in age profile for each year is the number of assets with an installation date in that year. Assets with no installation date in the Maximo, Q4 and SDME Asset Management Systems or an installation date of 1901 (which is a default for an unknown installation date) have been included in the age profile in the final year (1910/11) in Table 5.2.1.

The Economic Life and Standard Deviation for each asset has been based on asset lives included in the 2012 Replacement Expenditure model (model template provided by the AER). The asset life data in the 2012 Replacement Expenditure Model were developed based on engineering judgment from subject matter experts within the business. The asset categories in the 2012 Repex model have been aligned with the AER asset categories to populate the required Economic Life information.

In relation to data provided for the Service Lines Asset Group, a different preparation methodology was performed due to limitations in data availability. Overhead Service Lines data is currently collected in two Asset Management Systems (SDMS and Q4). Q4 contains the total number of Overhead Service Connections but does not include installation dates. SDME contains installation dates and average total length of Overhead Service Cable but currently does not include all of the assets in this category.

To derive an estimate of the Service Lines age profile, total quantity of Service Connections was extracted from Q4. This was multiplied by the total quantity by the 'Average length per Service' based on data from SDME. This provided a total length of service cable in kilometres. Using the installation dates from SDME, an asset age profile was created with a total length to match the amount calculated above.

Estimated Information:

Data provided in Table 5.2.1 is considered estimated information.

The information extracted from the Asset Management Systems is current data as at May 2014. This is due to the Asset Management Systems being 'live' databases. System limitations prevent asset reports being run as at specific (historic) points in time.

As outlined above, estimates and assumptions have been applied to align the SPI Electricity asset categories (per the Asset Management Systems) with the prescribed AER asset categories. Additionally, the Economic Life for each asset was estimated based on information in the 2012 Replacement Expenditure model (model template provided by the AER). Assumptions were applied to align the categories in this model into the prescribed categories.

The information provided in Table 5.2.1 is considered Management's best estimate of the data required based on the information available.

5.3 MD - Network level

Table 5.3.1 – Raw and Weather Corrected Coincident Maximum Demand at Network Level (Summed at Transmission Connection Point)

Raw Network Coincident Maximum Demand, Date MD Occurred, Half Hour Time Period MD Occurred, Winter/ Summer Peaking and Embedded Generation

Maximum demand has the meaning prescribed in the National Electricity Rules. Maximum demand refers to 30 minute demand unless otherwise indicated.

Preparation Methodology:

Information was sourced from the Scada (OSI Pi) system for all Regulatory Years by zone substation.

Daily coincidental maximum demand data was extracted from Scada for each site for all days in the 2009 to 2013 Regulatory Years. Using this information, the maximum demand day was identified for each year. 30 minute maximum demand data was extracted from Scada for each zone substation, providing daily coincidential maximum demand information. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for each Regulatory Year.

Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) was identified. This information, and the sum of the demands at each zone substation, were reported in Table 5.3.1.

Embedded Generation data is sourced from an SPI Electricity Oracle SQL database which is populated using data from the Billing System. The meter data for each 30 minute period (for the coincidental and non-coincidental time periods) for each applicable zone substation is extracted using a database query. For the coincidental time periods, this is the summation of all embedded generation data for the coincidental time that the network peaks. Embedded Generation information was not available from the database for the 2009 Regulatory Year. As such, this information has been estimated as the average of the Embedded Generation data for the 2010 to 2013 Regulatory Years.

Estimated Information:

All information provided is considered actual information, with the exception of the 2009 Embedded Generation data. The data provided is considered Management's best estimate based on the information available.

Weather Corrected Coincident Maximum Demand

SPI Electricity does not calculate or maintain historical weather corrected coincident maximum demand data. On this basis the 'Weather Corrected' data cells have been shaded black.

5.4 MD & utilisation - spatial

Table 5.4.1 – Non-coincident Maximum Demand

Sub-transmission Substations

Based on the prescribed AER definitions, Sub-transmission substations are substations on a distribution network that transform any voltage to levels above 33 kv.

SPI Electricity does not own any sub-transmission substations above 33kv. Based on this, the table requiring non-coincident maximum demand at the sub-transmission substation level has not been completed.

Zone Substation

Non-coincident maximum demand has been reported at the zone substation level.

Substation Rating

Substation rating refers to normal summer cyclic rating ("SCR").

Preparation Methodology:

Substation rating information was sourced from the Asset Management System. Based on SPI Electricity's internal document 'AMS 20-101 Zone Substation Transformer Cyclic Ratings', Substation output ratings are derived by using 'Transp' excel-based program which takes into account the transformers' cyclic rating, impedance, minimum tap, load power factor and available capacitor bank in the station.

Estimated Information:

Information provided is considered actual information, no estimates or assumptions have been applied.

Raw Adjusted Maximum Demand (MW), Raw Adjusted Maximum Demand (MVA), Date MD Occurred, Half Hour Time Period MD Occurred, Winter/ Summer Peaking and Embedded Generation

Preparation Methodology:

Information was sourced from the OSI Pi (Scada) system for all Regulatory Years.

A list of all zone substations and feeders was compiled based on a combination of the latest zone substation forecasts and the 2011-15 EDPR submission, to ensure all zone substations in the reporting period were accounted for.

Daily non-coincidental maximum demand data was extracted from Scada for each site for the entire period. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for each Regulatory Year.

30 minute maximum demand data was extracted from Scada for each zone substation, providing daily coincidential maximum demand information (date, time). Daily coincidental maximum demand data was extracted from Scada for each site for the entire period. Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for each Regulatory Year.

Embedded Generation Data is sourced from an SPI Electricity Oracle SQL database which is populated using data from the Billing System. The meter data for each 30 minute period (for the coincidental and non-coincidental time periods) for each applicable zone substation is extracted using a SQL query. For non-coincidental time periods, this is the embedded generation data for the non-coincidental time that the zone substation peaks.

<u>Estimated Information:</u>

Information provided is considered actual information, no estimates or assumptions have been applied

Weather Corrected Coincident Maximum Demand

SPI Electricity does not calculate or maintain historical weather corrected coincident maximum demand data. On this basis the 'Weather Corrected' data cells have been shaded black for all zone substations.

6.3 Sustained Interruptions

A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premise. The customer interruption starts when it is recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. It does not include subsequent interruptions caused by network switching during fault finding. An interruption ends when supply is again generally available to the customer.

Both planned and unplanned interruptions to supply have been reported. A planned supply interruption is where SPI Electricity planned the interruption to supply and customers were notified in advance.

An unplanned interruption is an interruption due to an unplanned event. An unplanned event is an event that causes an interruption where the customer has not been given the required notice of the interruption or where the customer has not requested the outage.

The following events may be excluded when calculating the revenue increment or decrement under the service target performance incentive scheme (“STPIS”) when an interruption on the distribution network has not already occurred or is concurrently occurring at the same time:

(a) load shedding due to a generation shortfall
(b) automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition
(c) load shedding at the direction of the Australian Energy Market Operator (“AEMO”) or a system operator
(d) load interruptions caused by a failure of the shared transmission network
(e) load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning
(f) load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation.

An event may also be excluded where daily unplanned SAIDI for SPI Electricity’s distribution network exceeds the major event day boundary, as set out in the STPIS scheme, when the event has not been excluded under clause 3.3(a) of the AER STPIS guidelines.

For the purpose of completing Table 6.3.1 Sustained Interruptions to Supply, the following definitions were applied:

Feeder Classification	CBD feeder: a feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas. Urban feeder: a feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km. Short rural feeder: a feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km. Long rural feeder: a feeder which is not a CBD or urban feeder with a total feeder route length greater than 200 km.
Effect on unplanned SAIDI (by feeder classification)	The sum of the duration of each unplanned sustained customer Interruption in minutes divided by the total number of distribution customers. USAIDI excludes momentary interruptions (one minute or less).
Effect on unplanned SAIFI (by feeder classification)	The total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.
MED ("Major Event Days")	Has the same meaning as specified in the STPIS scheme.

Table 6.3.1 - Sustained interruptions to supply

Preparation Methodology:

Network Outage Summary reports were extracted from the Business Intelligence Enterprise Data Warehouse ("BI/EDW"). From these reports, Planned, Unplanned and Momentary outage data was obtained by Project ID or Incident Reference Number.

For each unique Project ID or Incident Reference Number, the Minutes-Off Supply ("MOS") and Number of Customers Interrupted ("Cust-Int") were aggregated. Each record identifies the feeder name and outage cause.

Using the feeder name, and with reference to previous AER Annual Reliability Reports, the feeder classification information was added to each outage record. Feeder classification information is maintained in the BI/EDW system.

For each record, the outage cause (per the system data) was aligned with the options in Table 6.3.1 'Reason for Interruption' and 'Detailed Reason for Interruption'. Where the 'Reason for Interruption' was unknown, this has been identified and the 'Detailed Reason for Interruption' has been listed as 'Unknown'. In relation to interruptions caused by vegetation, the 'Detailed Reason for Interruption' is not known as this level of information was not captured in the system and has not been previously reported. Based on this, the 'Detailed Reason for Interruption' has been 'blacked out' for vegetation related interruptions to supply. All other 'black outs' under 'Detailed Reason for Interruption' are in accordance with the template guidelines prescribed by the AER.

Using the data described above, the following calculations were performed for each outage record -

- Average Duration = MOS / Cust-Int
- USAIDI = MOS / Total Number of Customers
- USAIFI = Cust-Int / Total Number of Customers

It is noted that MOS can be either Planned or Unplanned.

The 'Total Number of Customers' was obtained from the AER Annual Performance Reports and was calculated as (January 2013 count + December 2013 count)/2.

In relation to MEDs, the MED threshold was calculated for the 2013 Regulatory Year from the daily Unplanned SAIDI data between Regulatory Years 2008 and 2012 (5 years) using the annual AER RIN Template MED calculator. Calculations performed were in accordance with the requirements of the STPIS. The calculated MED threshold was then applied as the threshold for all Regulatory Years for the purpose of identifying MEDs.

<u>Estimated Information:</u>

Information reported is considered actual information. No estimates were required.