Ausgrid response to AER Reset Regulatory Information Notice

Response to Reset Regulatory Information Notice issued by AER on 7 March 2014 (amended 21 March)

30 May 2014

Contents

Introduction

Purpose of this document

This document represents Ausgrid's written response to the Reset Regulatory Information Notice (Reset RIN), issued to Ausgrid by the AER on 7 March 2014 and amended on 21 March 2014. The purpose of this response is to address each of the requirements contained in Schedule 1 of the Reset RIN.

In addressing the requirements of Schedule 1, we have identified where information has been provided or supplemented in the documents that comprise our overall response to the Reset RIN, consisting of the following documents:

- The completed regulatory templates set out in Appendix A of the Reset RIN, as required under paragraph 1.1 of Schedule 1 and in accordance with the AER's Notice including Appendix E. This is termed "Ausgrid's completed regulatory templates". These are provided at Attachment A Ausgrid's Completed Regulatory Templates.
- The Basis of Preparation as required in paragraph 1.2 of Schedule 1. This is termed "Ausgrid's Basis of Preparation" and has been undertaken in accordance with the additional instructions set out in Schedule 2 of the AER's notice and Appendix E. This is provided at Attachment B Ausgrid's Basis of Preparation.
- The Audit and Review reports as required in paragraph 32 Schedule 1 of the AER's notice, and have been prepared in accordance with the requirements set out in Appendix C of the AER's notice. This is termed "The Audit and Review Reports" and contains a single PDF of each report. These are provided at Attachment C Audit and Review Reports.
- The board resolution required in paragraph 33 of Schedule 1 of the AER's Notice. This is termed "Ausgrid's Board resolution". This is provided at Attachment D Ausgrid's Board Resolution.

As required by paragraph 1.5(e) of Schedule 1, we must submit a table that references each response to a paragraph in this Schedule 1, where it is provided in or as part of the regulatory proposal. In effect, this element of the Notice enables a DNSP to respond to a particular question in Schedule 1 by reference to documentation submitted as part of our regulatory proposal. Due to the size of this information, our detailed response to Question 1.5(e) is set out separately as an attachment to this document, titled Table of Regulatory Proposal References. This is provided at Attachment E Table of Regulatory Proposal References.

Structure of this document

Schedule 1 requires Ausgrid to provide information on 36 matters. Each of these matters is addressed below in an individual section corresponding to the structure of Schedule 1 of the Reset RIN.

Where the answer to a Reset RIN requirement is provided as part of Ausgrid's 2014-19 regulatory proposal a reference has been provided to the relevant part of the regulatory proposal. These references fall into one of three categories:

- A chapter in Ausgrid's regulatory proposal document, denoted using a chapter reference number;
- An attachment provided as part of Ausgrid's regulatory proposal denoted using an attachment reference number; and
- A reference to a supporting document provided as part of Ausgrid's regulatory proposal, denoted using a supporting document ID and title.

In addition, certain information in support of the answers contained in this document has been provided by way of attachments.

1. PROVIDE INFORMATION

1.1 Provide the information required in each Regulatory template in the Microsoft Excel Workbooks attached at Appendix A completed in accordance with:

a) this Notice;

b) the instructions in the Microsoft Excel Workbooks attached at Appendix A;

c) the Principles and Requirements in Appendix E; and

d) the service classifications set out in the framework and approach paper.

Ausgrid has provided the information required in each Regulatory template in the Microsoft Excel Workbooks attached at Appendix A of the Reset RIN. These workbooks have been completed in accordance with:

- the Reset RIN;
- the instructions in the workbooks;
- the Principals and Requirements in Appendix E; and
- the service classifications set out in the framework and approach paper.

1.2 For information other than Forecast Information, provide in accordance with this Notice and the Principles and Requirements in Appendix E, a Basis of Preparation demonstrating Ausgrid has complied with this Notice, in respect of:

a) the information in each Regulatory template in the Microsoft Excel Workbooks attached at Appendix A; and

b) any other information prepared in accordance with the requirements of this Notice.

Ausgrid has provided a Basis of Preparation for information other than Forecast Information, in accordance with the Reset RIN and the Principles and Requirements in Appendix E.

The Basis of Preparation demonstrates Ausgrid has complied with the RIN, in respect of:

- the information in each regulatory template attached to the RIN; and
- any other information prepared in accordance with the requirements of the RIN.

The Basis of Preparation document has been provided as a separate document, and accompanies the completed Regulatory Templates.

1.3 Provide any other supporting information or documentation that is directly relevant to the preparation of the regulatory proposal.

All supporting information or documentation that is directly relevant to the preparation of the regulatory proposal has been provided either in:

- Ausgrid's regulatory proposal including the proposal itself, attachments, and supporting documents;
- Regulatory Templates and accompanying Basis of Preparation; and
- This Written Response to the Reset RIN.

1.4 Provide the applicable cost allocation methodology.

Ausgrid's applicable Cost Allocation Methodology (CAM) is provided at Attachment 5.10 to the regulatory proposal.

1.5 Provide for the purposes of the preparation of the regulatory proposal:

a) all economic analysis used to justify expenditure;

The AER has defined economic analysis as any analysis pertaining to the costs, benefits and related impacts of a decision or activity previously or as yet to be undertaken by Ausgrid. We consider that the definition would capture information relating to the following categories of documents, which we have submitted as part of our suite of supporting documents in the regulatory proposal.

- Documents which provide further guidance on how we undertake economic analysis, such as use of discount rates and net present value analysis (NPV).
- Business cases or options analysis relating to capex or opex projects justifying expenditure decisions. This includes our Area Plan related documents, Asset Condition and Planning documents (ACAPs), model data for our 11kV, low voltage and customer connections, and business cases for our technology and corporate property investments. We consider these would be the primary type of document captured by the term 'economic analysis' as it sets out the need, options, costs and benefits of investment. It would also include decisions to undertake new opex programs such as broad based demand management, where an options/ NPV type analysis has been undertaken.
- Information relating to costs which directly input into economic analysis such as descriptions of our unit cost and escalation methodologies, and documents that set out specific costings of programs. We note that some of this material may lie within the business case document such as for technology plans.

Table 1 provides a list of all documents that meet these criteria.

Table 1 Documents provided in regulatory proposal that are economic analysis used to justify expenditure

Attachment number/ supporting document	ID	Document name
5.15	ID78779	Overview of the unit cost methodology
5.16	ID36536	Overview of the cost escalation methodology
5.17	ID35107	Cost escalation inputs and model
5.18	ID94028	Independent economics – Labour escalation for NSW DNSPs
5.19	ID04288	CEG - Material escalation for NSW DNSPs
6.12	ID71045	Demand management operating expenditure plan
8.09	ID00248	Public lighting investment plan – active reactors (CONFIDENTIAL)
8.10	ID00249	Public lighting investment plan – Replacement of twin 20 luminaires (CONFIDENTIAL)
8.11	ID00250	Public lighting investment plan- Replacement of 42W CFL with LED (CONFIDENTIAL)
8.12	ID93661	Public Lighting Opex Forecast (CONFIDENTIAL)

Attachment number/ supporting document	ID	Document name
8.13	ID69562	Public lighting models (CONFIDENTIAL)
Supporting Ch 5	ID00074	(INV-STD-10024) Planning Standard - Economic Appraisal
Supporting Ch 5	ID27832	Area plan projects - 2013 review of preferred strategies
Supporting Ch 5 - Area plans	ID92461	Area Plan 1 - Lower Central Coast
Supporting Ch 5 - Area plans	ID05927	Area Plan 2 - Upper Central Coast
Supporting Ch 5 - Area plans	ID76443	Area Plan 3 - Camperdown & Blackwattle Bay
Supporting Ch 5 - Area plans	ID79200	Area Plan 4 - Sydney CBD area plan
Supporting Ch 5 - Area plans	ID56130	Area Plan 5 - Eastern Suburbs
Supporting Ch 5 - Area plans	ID09699	Area Plan 6 - Terrey Hills
Supporting Ch 5 - Area plans	ID65159	Area Plan 7 - Manly Warringah
Supporting Ch 5 - Area plans	ID84206	Area Plan 8 - Upper North Shore
Supporting Ch 5 - Area plans	ID42238	Area Plan 9 - Lower North Shore
Supporting Ch 5 - Area plans	ID11200	Area Plan 10 - Carlingford
Supporting Ch 5 - Area plans	ID75822	Area Plan 11 - North West
Supporting Ch 5 - Area plans	ID45886	Area Plan 12 - Inner West
Supporting Ch 5 - Area plans	ID67283	Area Plan 13 - Sutherland

Attachment number/ supporting document	ID	Document name
Supporting Ch 5 - Area plans	ID79350	Area Plan 14 - St. George
Supporting Ch 5 - Area plans	ID83354	Area Plan 15 - Canterbury Bankstown
Supporting Ch 5 - Area plans	ID29070	Area Plan 16 - North East Lake Macquarie
Supporting Ch 5 - Area plans	ID15229	Area Plan 17 - Port Stephens
Supporting Ch 5 - Area plans	ID40674	Area Plan 18 - Newcastle Inner City
Supporting Ch 5 - Area plans	ID18374	Area Plan 19 - Western Corridor
Supporting Ch 5 - Area plans	ID92627	Area Plan 20 - West Lake Macquarie
Supporting Ch 5 - Area plans	ID85326	Area Plan 21 - Newcastle Ports
Supporting Ch 5 - Area plans	ID08624	Area Plan 22 - Maitland
Supporting Ch 5 - Area plans	ID06271	Area Plan 23 - Upper Hunter
Supporting Ch 5 - Area plans	ID93581	Area Plan 24 - Greater Cessnock
Supporting Ch 5 - Area plans	ID39556	Area Plan 25 - Singleton
Supporting Ch 5 - Area plans	ID44497	Area Plan 26 - Inner Metro / Transmission
Supporting Ch 5 - Area plans	ID49125	Area Plan 27 - Central Coast Transmission plan
Supporting Ch 5 - Area plans	ID14220	Area Plan 28 - Lower Hunter Transmission Plan
Supporting Ch 5 - Area plans	ID29286	Network Property Plan

Attachment number/ supporting document	ID	Document name
Supporting Ch 5 - Area plans	ID75799	Conditional Projects
Supporting Ch 5 - Area plans	ID83702	Strategic asset prioritisation - 11kV switchgear
Supporting Ch 5 - Area plans	ID00144	Rationale for fixed pattern 11kV switchgear
Supporting Ch 5 - Area plans	ID17517	Strategic Asset Prioritisation subtransmission cables
Supporting Ch 5 - Area plans	ID00075	Methodology and cost estimates for pricing substations, feeders and 11kV switchboard replacement - Volumes 1 to 9
Supporting Ch 5 - Area plans	ID00077	Methodology for cost estimates for 11kV feeder transfers for Area Plans
Supporting Ch 5 - Replacement and duty of care plans	ID95984	ACAPS1001 Pole Mounted Substations
Supporting Ch 5	ID12821	ACAPS1002 Chamber and Outdoor Enclosure Substations
Supporting Ch 5	ID79488	ACAPS1003 Kiosk Type Substations
Supporting Ch 5	ID76077	ACAPS1004 Sydney CBD Underground Substations
Supporting Ch 5	ID69728	ACAPS1005 RMU, FS and I&E Switchgear
Supporting Ch 5	ID83495	ACAPS1006 HV and LV Switchgear
Supporting Ch 5	ID11805	ACAPS2001 Battery Systems
Supporting Ch 5	ID10969	ACAPS2002 Building Structures
Supporting Ch 5	ID00131	ACAPS2003 Protection and Control Systems (Reactive)
Supporting Ch 5	ID39247	ACAPS2004 Circuit Breakers and Fault Throwers

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID87011	ACAPS2005 CLC Schemes
Supporting Ch 5	ID34295	ACAPS2006 Isolator Switches
Supporting Ch 5	ID91441	ACAPS2008 Reactive Replacement <$50k
Supporting Ch 5	ID84318	ACAPS2009 Secondary Protection & Control Systems
Supporting Ch 5	ID78587	ACAPS2012 11kV Switchboard & Circuit Breakers
Supporting Ch 5	ID04397	ACAPS3001 Capacitor Banks
Supporting Ch 5	ID52955	ACAPS3003 Substation Ancillary Equipment
Supporting Ch 5	ID00049	ACAPS3004 Substation Earthing
Supporting Ch 5	ID08260	ACAPS3006 MPLS Network Switch and Router Equipment
Supporting Ch 5	ID30414	ACAPS3007 Instrument Transformers
Supporting Ch 5	ID06234	ACAPS4001 Overhead Support Structures
Supporting Ch 5	ID37578	ACAPS4002 Steel Mains and ACSR
Supporting Ch 5	ID05744	ACAPS4003 HV Air Break Switches and Underslung Links
Supporting Ch 5	ID02420	ACAPS4004 Overhead Mains Reactive Conductor Replacement (km)
Supporting Ch 5	ID06700	ACAPS4005 Re-establish Distribution Access Tracks (km)
Supporting Ch 5	ID72275	ACAPS4007 11kV Voltage Regulators

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID77594	ACAPS4010 Low Voltage Overhead Services
Supporting Ch 5	ID90973	ACAPS4020 11/5kV Underground Cable Reactive Replacement (km)
Supporting Ch 5	ID26549	ACAPS4030 Low Voltage Underground CONSAC Cable
Supporting Ch 5	ID98981	ACAPS4031 Low Voltage Underground HDPE Cable
Supporting Ch 5	ID87182	ACAPS4032 Low Voltage Underground Cable Reactive Replacement (km)
Supporting Ch 5	ID42227	ACAPS4040 Distribution Mains Reactive Unit Replacement
Supporting Ch 5	ID29733	ACAPS4041 Storms, Bushfires and Natural Disasters
Supporting Ch 5	ID08199	ACAPS5001 Transmission Overhead - Steel Towers
Supporting Ch 5	ID65155	ACAPS5002 Earthing: Sub-Transmission Feeders
Supporting Ch 5	ID68172	ACAPS5003 Transmission Overhead - Feeder refurbishment
Supporting Ch 5	ID72876	ACAPS5004 Transmission Overhead - Ground Anchors
Supporting Ch 5	ID87984	ACAPS5005 Miscellaneous and Reactive programmes
Supporting Ch 5	ID27869	ACAPS5007 Sub-transmission Underground - Cable Pressure Alarm Replacement
Supporting Ch 5	ID40391	ACAPS6001 Oil Containment
Supporting Ch 5	ID00048	ACAPS6002 Noisy Equipment - DC
Supporting Ch 5	ID99420	ACAPS6003 Reactive Environmental Projects

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID95710	ACAPS6004 Reactive Asbestos Projects
Supporting Ch 5	ID73741	ACAPS6006 Asbestos Fire Doors
Supporting Ch 5	ID29726	ACAPS6007 Underground Substation Cascade Modernisation
Supporting Ch 5	ID16982	ACAPS6008 Kiosk with Exposed 11kV
Supporting Ch 5	ID45383	ACAPS6010 Reactive OH&S Projects
Supporting Ch 5	ID27760	ACAPS6011 Optical Arc Fault Detection
Supporting Ch 5	ID24899	ACAPS6012 AC & DC Boards
Supporting Ch 5	ID60160	ACAPS6013 Mackellar Chamber Substations
Supporting Ch 5	ID88751	ACAPS6015 Fire Mitigation
Supporting Ch 5	ID97515	ACAPS6016 Fire Mitigation in Distribution Substations
Supporting Ch 5	ID97872	ACAPS6017 Perimeter Fencing for Distribution Substations
Supporting Ch 5	ID75814	ACAPS6018 Brick Wall Outdoor Enclosure Substations
Supporting Ch 5	ID80567	ACAPS6019 Perimeter Fencing
Supporting Ch 5	ID01248	ACAPS6021 Water Crossings
Supporting Ch 5	ID30153	ACAPS6022 Low Mains
Supporting Ch 5	ID20985	ACAPS6023 Relocate Poles in RMS Black-spots

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID02987	ACAPS6024 Reactive Electrical Safety Projects
Supporting Ch 5	ID06964	ACAPS6025 Electronic Security
Supporting Ch 5	ID56534	ACAPS6026 Reactive Infrastructure Risk Projects
Supporting Ch 5	ID68705	ACAPS6027 LV Board Screening
Supporting Ch 5	ID63230	ACAPS6028 Distribution Substation Security Program
Supporting Ch 5	ID95743	ACAPS7001 System Spares Equipment - DC Subs
Supporting Ch 5	ID57936	ACAPS7002 System Spares - Distribution Mains
Supporting Ch 5	ID98615	ACAPS7004 Spares Storage Facilities - Zone
Supporting Ch 5	ID04721	ACAPS7005 System Spares - Transmission Mains
Supporting Ch 5	ID40835	ACAPS7006 System Spares - Zone & STS Substations
Supporting Ch 5	ID57130	ACAPS7007 Transformer Replacement & Spares Programs
Supporting Ch 5	ID00129	Spares Strategy (ASM-STG-10004)
Supporting Ch 5	ID97884	Risk Quantification Methodology
Supporting Ch 5	ID07366	Replacement & Duty of Care Plan (distribution projects) unit cost methodology
Supporting Ch 5	ID33420	Replacement & Duty of Care Plan unit costs
Supporting Ch 5	ID50068	11kV model: Method and Outcomes of DND (explanatory)

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID21349	DND (11kV) model
Supporting Ch 5	ID60868	Low Voltage capex model: Method and Outcomes (explanatory)
Supporting Ch 5	ID56211	LV volumes model
Supporting Ch 5	ID92279	LV cost of delivery table
Supporting Ch 5	ID81882	Customer connections capex model: Method and Outcomes (explanatory)
Supporting Ch 5	ID97008	Customer connections model: volumes
Supporting Ch 5	ID70090	Customer connections cost of delivery table
Supporting Ch 5	ID68195	Feeder Category Reliability Forecast System Methodology
Supporting Ch 5	ID33258	Feeder Category Reliability Forecast System (spreadsheet)
Supporting Ch 5	ID96854	Reliability CAPEX Forecast calculation
Supporting Ch 5	ID00109	Technology Plan Business Case 01 - Regulatory Changes to Market & Enterprise Systems
Supporting Ch 5	ID00111	Technology Plan Business Case 02 - Technology Licence Growth
Supporting Ch 5	ID00115	Technology Plan Business Case 03 - Information, Communication & Technology Security
Supporting Ch 5	ID00116	Technology Plan Business Case 04 - End of Life Application Upgrades
Supporting Ch 5	ID00117	Technology Plan Business Case 05 - Mandatory Patch & Release Management
Supporting Ch 5	ID00118	Technology Plan Business Case 06 - SAP Core Maintenance

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID00119	Technology Plan Business Case 07 - Infrastructure Capacity & Maintenance
Supporting Ch 5	ID00120	Technology Plan Business Case 08 - Workplace Technology
Supporting Ch 5	ID00121	Technology Plan Business Case 09 - Telecommunications Platform Maintenance
Supporting Ch 5	ID00122	Technology Plan Business Case 10 - Distribution Monitoring & Control Rollout
Supporting Ch 5	ID00123	Technology Plan Business Case 11 - Fieldforce Automation Program
Supporting Ch 5	ID00124	Technology Plan Business Case 12 - Distribution Network Monitoring System (DNMS) and Supervisory Control and Data Acquisition (SCADA)
Supporting Ch 5	ID00137	Technology Business Case 18 - Network Secondary Systems Platform Maintenance
Supporting Ch 5	ID17472	Technology Plan costing methodology and estimates
Supporting Ch 5	ID00138	Benefits Framework
Supporting Ch 5	ID59345	Business case 1 - HOB relocation to Roden Cutler House
Supporting Ch 5	ID46954	Business case 2 - Alexandria new depot (zip including supporting documents)
Supporting Ch 5	ID61850	Business case 3 - Homebush depot master plan implementation (zip including supporting documents)
Supporting Ch 5	ID95512	Business case 4 - Potts Hill depot master plan implementation (zip including supporting documents)
Supporting Ch 5	ID17697	Business case 5 - Chatswood depot master plan implementation (zip including supporting documents)
Supporting Ch 5	ID91748	Business case 6 - Oatley depot master plan implementation (zip including supporting documents)
Supporting Ch 5	ID33790	Business case 7 - Dee Why depot master plan implementation (zip including supporting documents)

Attachment number/ supporting document	ID	Document name
Supporting Ch 5	ID68533	Business case 8 - Wallsend depot master plan implementation (zip including supporting documents)
Supporting Ch 5	ID25831	Business case 9 - Maitland depot master plan implementation (zip including supporting documents)
Supporting Ch 5	ID00024	Business Case 10 - Other Capex

b) all consultants' reports commissioned and relied upon in whole or in part;

We have interpreted the term 'consultants' reports' to be any report branded by an external person or company that we have either engaged or whose work we have relied on to justify an element of our regulatory proposal. This would include the following types of documents we have submitted in our regulatory proposal:

- External assurance reports to confirm accuracy and reliability of data, for example assurance reports on our models.
- Expert advice on key inputs used to develop rate or return estimates or forecasts of expenditure, for example real cost escalation.
- Reviews of our program/ projects or total expenditure which provides advice on our forecasts, for instance Huegin benchmarking reports.
- Advice on how to prepare forecasts, or provide evidence in accordance with the Rules, for example advice on economic interpretation of the Rules for capex and opex.
- Review of past performance, for example reviews of outcomes in the previous period.

The consultant reports that we have relied upon have been provided in our supporting documentation in our regulatory proposal, and are identified in Table 2.

Table 2 Consultant reports commissioned or relied on in Ausgrid's regulatory proposal documents

Attachment no/ supporting document	ID	Document name
2.02	ID65422	Customer engagement survey
4.12	ID92680	EY - Regulatory treatment of risk
5.01	ID02326	Arup review of outcomes for the 2009-14 regulatory period
5.18	ID94028	Independent economics - Labour escalation for NSW DNSPs
5.19	ID04288	CEG - Material escalation for NSW DNSPs

Attachment no/ supporting document	ID	Document name
5.32	ID74807	Economic Interpretation of clauses 6.5.6 and 6.5.7 of the NER (Meaning of prudency and efficiency)
5.33	ID65504	Addressing the benchmarking factor for capex and opex (including Huegin, Evans & Peck, Repex and Augex)
7.01	ID00252	Debt transition and the NER and NEL
7.02	ID26452	Calculation of proposed cost of debt and equity for NSW DNSPs
7.03	ID00110	Efficiency of staggered debt issuance
7.04	ID00225	Transition to the benchmark cost of debt
7.05	ID00226	[CONFIDENTIAL] Advice to Networks NSW
7.06	ID00227	Credit ratings for NSPs
7.07	ID00228	Debt raising costs for NSW DNSPs - Individual reports for Ausgrid, Endeavour and Essential
7.08	ID03705	Scientific Background on the Sveriges Riskbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, UNDERSTANDING ASSET PRICES
7.09	ID00222	The Fama-French Three-Factor Model
7.10	ID00229	The market, size and value premiums
7.11	ID00230	MRP, analysis in response to the AER's draft rate of return guideline
7.12	ID00231	Estimating the return on the market
7.13	ID00232	Estimating the E[Rm] in the context of recent regulatory debate
7.14	ID00234	DGM based estimates of the Expected return on the market

Attachment no/ supporting document	ID	Document name
7.15	ID00235	Black CAPM
7.16	ID00236	Expert report on equity beta
7.17	ID00237	Regression-based estimates of risk parameters for the benchmark firm
7.18	ID00238	Equity beta issues paper: International comparators
7.19	ID00239	Information on equity beta from US companies
7.20	ID00240	Comparison of OLS and LAD regression techniquest for estimating beta
7.21	ID00241	Beta - The Vaiscek adjustment to beta estimates in the CAPM
7.22	ID00242	Reliability of regression based parameter estimates of risk
7.23	ID00243	Water utility beta estimation
7.24	ID00223	Generic gamma chapter on Rule Compliance (developed to be tailored as a standalone attachment)
7.25	ID00224	An appropriate regulatory estimate of gamma
7.26	ID00244	Imputation credits and equity prices and returns
7.27	ID00245	Updated dividend drop-off estimate of theta
7.28	ID00246	The payout ratio
7.29	ID00162	Imputation credit redemption data
8.21	ID00220	Energeia review of Ausgrid's metering tariffs
Supporting Ch 5	ID90027	SKM review of Ausgrid's peak demand forecast method

Attachment no/ supporting document	ID	Document name
Supporting Ch 5	ID50783	EY Audit report of Ausgrid's BPC models
Supporting Ch 5 - Area plans	ID00212	SKM review of subtransmission cable replacement strategy
Supporting Ch 5	ID97884	Risk Quantification Methodology
Supporting Ch 6	ID00259	KPMG review of opex models
Supporting Ch 8	ID45068	Benchmarking report on public lighting

c) all material assumptions relied upon;

Under Schedule 6.1.1 and 6.1.2 of the Rules, we are required to provide the key assumptions that underlie the capital and operating expenditure forecast respectively, together with a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider.

The term 'key assumption' is not a defined term or concept in the Rules. Previously accepted practice has been that there are a small number of high level assumptions relating to facts or circumstances, the truth or correctness of which underpins or is highly material to the expenditure forecasts.

We have identified our key assumptions in Table 3 which we also consider captures the concept of materiality.

Table 3 Key assumptions relied upon

Key assumption 1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.
Key assumption 2	The capital program has been prepared on the basis of amendments to the NSW Reliability and Performance Licence Conditions that will come into effect on 1 July 2014.
Key assumption 3	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.
Key assumption 4	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.
Key assumption 5	Forecast labour cost escalation has been set consistent with our Enterprise Bargaining Agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant "Independent Economics".
Key assumption 6	The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.
Key assumption 7	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National

	Electricity Rules.
Key assumption 8	Ausgrid has supplied Transitional Services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination has yet to be given. A joint transition plan between the parties has a current target end date of 27 November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan timeline is achieved.

d) copies of the top ten contracts relating to the delivery of distribution services, by annual value, and any supporting information directly related to the procurement process for the services provided by these contracts (e.g. probity reports, Board minutes, tendering documents); and

Table 4 provides a summary of these contracts, including the annual value and a brief description of the contract. Ausgrid has provided relevant documentation for these contracts at confidential Attachment F Major Contracts Documentation.

Table 4 Summary of Ausgrid contracts for the delivery of distribution services

Contract name	Brief description of contract	Annual Value ($'000)
Contract Cable Laying Contract EA8120/10D	Contract cable laying for high voltage projects	[redacted]
Kiosks Substations Contract AG2869/11	Supply of kiosk substations	
Contract Cable Laying Contract EA8120/10C	Contract cable laying for high voltage projects	
Motor Vehicle Leasing Contract EA9449/07A	Leasing of motor vehicles	
Contract Cable Laying Contract 8120/10A	Contract cable laying for high voltage projects	
Contract Cable Laying Contract EA8120/10F	Contract cable laying for high voltage projects	
Power Transformers Contract EA7453/04A	Supply and delivery of power transformers (132/66/33kV)	
High Voltage and Low Voltage Cable Supply Contract EA1400/10B	Supply of HV and LV cable	
Telecommunications Contract EA8764/07	Provision of ICT services to Ausgrid	
Meter Reading Contract EA0587/09A	Provision of meter reading services	

e) a table that references each response to a paragraph in this Schedule 1, where it is provided in or as part of the regulatory proposal.

We have provided a Table of References as part of the accompanying documents to the proposal, at Attachment E.

1.6 Provide for each material assumption identified in the response to paragraph 1.5(c):

a) its source or basis;

In Table 5 below, we have documented the source and/or basis of each key assumption, noting the name of the relevant supporting document in our regulatory proposal.

Table 5 Source or basis of key assumptions

Assumption number	Description of assumption	Source document
Key assumption 1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.	The source document in our regulatory proposal which explains our legal entity, ownership and organisational structure is "Delivering efficiencies for our customers" which includes information on our ownership and organisational structure.
Key assumption 2	The capital program has been prepared on the basis of amendments to the NSW Design Reliability and Planning Licence Conditions that will come into effect on 1 July 2014.	The source document in our regulatory proposal is a copy of the DRP licence conditions, "Reliability and Performance Licence Conditions for DNSP, Minister for Energy, commencing 1 July 2014".
Key assumption 3	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.	The source document in our regulatory proposal which explains our prioritisation process under the strategic management framework is "Delivering efficiencies for our customers" which includes information on the prioritisation process that was used.
Key assumption 4	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.	The source documents in our regulatory proposal which provide/ explain the basis of our customer connections and spatial demand forecasts are: • The forecasts of load growth by location are contained in the attachment: "Spatial demand forecast by zones and substations". (ID33657) • The method used to develop those forecasts of load growth is contained in the supporting documents: "(INV-STD-10022) Planning Standard - Demand Forecast". • Customer number forecast methodology. • Customer number forecasts model.
Key assumption 5	Forecast labour cost escalation has been set consistent with our Enterprise Bargaining	The source documents in our regulatory proposal which provide/ explain the basis of

	Agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant "Independent Economics".	our forecast labour escalation foe casts are: • Overview of the cost escalation methodology • Cost escalation inputs and model • Independent economics - Labour escalation for NSW DNSPs.
Key assumption 6	The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.	The source document is chapter 6.3 of our regulatory proposal document which sets out how the 2012-13 base year was used.
Key assumption 7	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.	The source document in our regulatory proposal which explains the outcomes of customer engagement are: • Ausgrid's customer engagement strategy • Customer engagement survey.
Key assumption 8	Ausgrid has supplied Transitional Services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination has yet to be given. A joint transition plan between the parties has a current target end date of 27 November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan timeline is achieved.	The source document in our regulatory proposal which explains our legal entity, ownership and organisational structure is "Delivering efficiencies for our customers" which includes information on our ownership and organisational structure.

b) if applicable, its quantum;

In Table 6 below, we have set out whether the assumption can be quantified in terms of value.

Table 6 Quantum of key assumptions

Assumption number	Description of assumption	Quantum
Key assumption 1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.	There is no applicable quantum.
Key assumption 2	The capital program has been prepared on the basis of amendments to the NSW Reliability and Performance Licence Conditions that will come into effect on 1	No counter-factual plan has been developed to assess the difference this assumption made in isolation. However, comparing the outcomes of the 2012

Assumption number	Description of assumption	Quantum
	July 2014.	planning review (which did not consider this impact) and the 2013 review (which supports the submission) the difference in capacity expenditure forecast for the 14-19 period is $534M. This includes the impacts of both licence condition change assumptions and changes in the demand forecast.
Key assumption 3	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.	The process of investment prioritisation was not carried out in isolation of other changes to investment plans. However, the proposed 2014-19 capex as at November 2012 was $1.2bn higher than the expenditure forecast in the submission. Only a portion of this change would be attributable to the prioritisation element of the framework.
Key assumption 4	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.	Demand forecasts have reduced due to changes in underlying demand, and become more reliable due to changes in methodology. In combination this has meant the forecast for expenditure on capacity is $718.4M. (A reduction of $706M lower from actual 2009-14 expenditure). Connections account for $228.9M of this expenditure.
Key assumption 5	Forecast labour cost escalation has been set consistent with our Enterprise Bargaining Agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant "Independent Economics".	Real cost escalation for labour accounts for $80.1 million of the capex program.
Key assumption 6	The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.	No applicable quantum.
Key assumption 7	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.	No applicable quantum.
Key assumption 8	Ausgrid has supplied Transitional Services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination has yet to be given. A joint transition plan between the parties has a current target end date of 27	Upon termination of the TSA, Ausgrid's operational and fixed support cost of providing standard control services will increase due to the loss of scale and scope of being an integrated retail/network business. The cessation of the TSA has direct impact on operational areas of data

Assumption number	Description of assumption	Quantum
	November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan timeline is achieved.	operations and contact centre as well as support areas such as IT. The direct operational impact is $39.0 million. Ausgrid has made a commitment to offset the full annual impact of the TSA loss of synergy by the end of the next regulatory period to minimise the impact on customer pricing.

c) whether and how the assumption has been applied and was taken into account; and

In Table 7 below, we have set out whether the assumption has been applied and how this has been taken into account.

Table 7 Application of key assumptions

Assumption number	Description of assumption	Application/ Taken into account
Key assumption 1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.	Assumption was applied. Used as a basis for determining forecast opex and capex for the 2014-19 proposal, by identifying the prudent and efficient expenditure required to meet our obligations as a DNSP with incorporation of efficiencies identified under new structure.
Key assumption 2	The capital program has been prepared on the basis of amendments to the NSW Design Reliability and Planning Licence Conditions that will come into effect on 1 July 2014.	Assumption was applied. The reduction to capex as a result of the change in licence condition was applied by our network planners when developing the capacity capex forecasts.
Key assumption 3	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.	Assumption was applied. The reduction to capex as a result of the prioritisation process was applied by our network planners when developing and consolidating the final programs and projects used as a basis for total capex forecasts.
Key assumption 4	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.	Assumption was applied. The spatial demand forecasts (incorporating spot loads from customer connections) as a basis for forecasting capacity capex for the Area plans and 11kV Plans. The customer connection forecasts were applied to the low voltage and customer connection capital plans to identify forecast capex for 2014-19.
Key assumption 5	Forecast labour cost escalation has been set consistent with our Enterprise Bargaining	Assumption was applied.

	Agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant "Independent Economics".	Real cost escalators were applied as an input into our consolidation model (BPC) by escalating the component of capex related to labour by the relevant real cost escalators.
Key assumption 6	The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.	Assumption was applied. This was used as the basis for deriving the efficient forecast opex for the 2014-19 period, by using the actual cost incurred in 2012-13 for cost categories that were re-current in nature.
Key assumption 7	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.	Assumption was applied. We note that the outcomes of customer engagement confirmed that our objectives in relation to maintaining current standards of reliability and safety were valued by customers, and that we were meeting the needs of customers with respect to striving to contain the average movement of prices below CPI.
Key assumption 8	Ausgrid has supplied Transitional Services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination has yet to be given. A joint transition plan between the parties has a current target end date of 27 November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan timeline is achieved.	Assumption was applied. Used as a basis for determining forecast opex and capex for the 2014-19 proposal. Upon termination of the TSA, Ausgrid's operational and fixed support cost of providing standard control services will increase due to the loss of scale and scope of being an integrated retail/network business. The cessation of the TSA has direct impact on operational areas of data operations and contact centre as well as support areas such as IT and property.

d) the effect or impact of the assumption on the capital and operating expenditure forecasts in the forthcoming regulatory control period taking into account:

i) the actual expenditure incurred during the current regulatory control period; and

ii) the sensitivity of the forecast expenditure to the assumption

In Table 8 below, we have set out the effect of the assumption taking into account the actual expenditure incurred and the sensitivity of the forecast expenditure to the assumption.

Table 8 Expenditure impacts of key assumptions

Key Assumption	Actual expenditure incurred in current regulatory period	Sensitivity of forecast expenditure to this assumption
The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.	Relatively high. New organisational structure as a result of industry reform was relevant to reducing capex and opex in the last 2 years of the regulatory period. Further information on the impact of efficiencies achieved under industry reform is provided in the document "Delivering Efficiencies for our Customers" which shows the impact of the network reform project on savings over a 5 year period that spans the early years of the 2014-19 period.	Relatively high. The new organisational structure under industry reform has elicited efficiencies that would not have been incorporated. Further information on the impact of efficiencies achieved under industry reform is provided in the document "Delivering Efficiencies for our Customers" which shows the impact of the network reform project on savings over a 5 year period that spans the early years of the 2014-19 period.
The capital program has been prepared on the basis of amendments to the NSW Reliability and Performance Licence Conditions that will come into effect on 1 July 2014.	Not applicable. The change in licence conditions only applies from 1 July 2014.	Low to Medium. As noted above the reduction to capex as a result of the change in licence conditions is $534M which includes the impact of changes in demand forecasts.
Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.	Not applicable. The prioritisation method under the strategic management framework has only been applied to derive the capex forecast for the 2014-19 period, and therefore has not impacted the 2010-14 actual expenditure.	Relatively high. As noted above, the reduction to capex as a result of the prioritisation process was a proportion of the $1.2B reduction in forecast capital expenditure.
Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.	Medium. Growth was a key input to our actual capex in the 2010-14 period. It is difficult to precisely estimate the impact of demand forecast on capacity capex in the 2009-14 period due to the coinciding need to invest in the network to meet new security standards under our licence conditions.	Medium. As noted above, Ausgrid's capacity expenditure accounts for $718.4 million of the capex program. Connections account for $228.9M of this expenditure.
Forecast internal labour costs and wage rate increases have been set consistent with our Enterprise Bargaining Agreement (EBA) for the extent to which this applies, and that forecasts from that point on have been set based on data provided by Independent Economics.	Changes in the labour and construction costs were the major driver of our actual capex in the 2010-14 period.	Medium . As noted above, real cost escalation for labour accounts for $80.1 million of the capex program and $88.1 million for opex. This is based on a forecast average 1.8% real increase in labour costs during 2015-2019.
The opex year 2012/13 has	Not applicable. It is not possible to	Not applicable. It is not possible to provide

Key Assumption	Actual expenditure incurred in current regulatory period	Sensitivity of forecast expenditure to this assumption
been adopted as the efficient base year for deriving a forecast of recurrent opex.	provide a view on the sensitivity of the forecast, as this would require an alternative forecast using a zero base approach which has not been undertaken by Ausgrid.	a view on the sensitivity of the forecast, as this would require an alternative forecast using a zero base approach which has not been undertaken by Ausgrid.
Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.	Not applicable. Ausgrid was not subject to formal customer engagement guidelines in the 2010-14 period.	Medium. We consider that the customer engagement process has been a key driver of an approach that sought to improve affordability through lowering prices to the extent possible while still maintaining safety and reliability of services.
Ausgrid has supplied Transitional Services to EnergyAustralia since the sale of its retail business in 2011. The TSA has a maximum term until 31 December 2015. The required six months notice of termination has yet to be given. A joint transition plan between the parties has a current target end date of 27 November 2014 with post migration support obligations until 28 February 2015. In the event of EnergyAustralia being unable to transition due to unforeseen circumstances, the TSA contract has obligations on Ausgrid to continue providing services where Ausgrid has maintained the capability to provide the service. Ausgrid's regulatory proposal is based on the assumption that the current joint transition plan timeline is achieved.	Not applicable.	Medium. Upon termination of the TSA, Ausgrid's operational and fixed support cost of providing standard control services will increase due to the loss of scale and scope of being an integrated retail/network business. The cessation of the TSA has direct impact on operational areas of data operations and contact centre as well as support areas such as IT. The direct operational impact is $39.0 million. Ausgrid has made a commitment to offset the full annual impact of the TSA loss of synergy by the end of the next regulatory period to minimise the impact on customer pricing.

1.7 Capital and operating expenditure forecasts provided in the regulatory templates must be reconciled to the ex-ante capital and operating allowances in Post-Tax Revenue Model for the forthcoming regulatory control period.

Ausgrid has forecast its capex and opex for the regulatory proposal consistent with the cost drivers and cost categories we use in the day-to-day running of the business. The requirements in the RIN (or Notice) to categorise costs in different ways mean that simply adding up the expenditure presented in the templates will not immediately reconcile to the forecast expenditure proposed in our regulatory proposal, which is anticipated by the RIN.

For example, section 11.1 of Schedule 1 of the RIN requires certain costs to be reported in more than one place in the RIN:

> *If expenditure is directly attributable to an expenditure category in this regulatory template 2.6 it is a Direct Cost for the purposes of this regulatory template 2.6. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.*

It should also be noted that the PTRM capex and opex for the forthcoming regulatory period relates to only standard control services and the RIN, in parts, has requested expenditure relating to our total costs. This is another reason that the sum of the RIN expenditure needs to be adjusted to arrive at the PTRM expenditure.

Despite this, the regulatory proposal capex and opex forecasts have been used as the basis for the component parts of the templates in Attachment A, and we can confirm the forecast expenditure in the templates reconciles to the forecast expenditures in the PTRMs submitted in our regulatory proposal.

1.8 Where the regulatory proposal varies or departs from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme or service target performance incentive scheme as set out in the framework and approach paper, for each variation or departure explain:

a) the reasons for the variation or departure, including why it is appropriate;

b) how the variation or departure aligns with the objectives of the relevant scheme; and

c) how the proposed variation or departure will impact the operation of the relevant scheme.

Efficiency benefits sharing scheme (EBSS)

Ausgrid has adopted a base year approach to forecast most of its opex cost categories. We have adopted the actual opex of the financial year 2012-13, adjusted for actuarial assessment of long service leave obligations, as the efficient opex starting point upon which cost escalation and other change factors are applied to derive a total forecast opex that reasonably reflects the operating expenditure criteria.

As explained in Section 3.3 of Ausgrid's regulatory proposal, this adjustment is appropriate and necessary to ensure that the forecast opex reflects the underlying opex required to achieve the operating expenditure objectives and the opex needed to provide standard control services. This approach is consistent with the approach Ausgrid used to forecast the opex of the current 2009-14 period approved by the AER.

We note that the objective of the EBSS is to reward/penalise a DNSP for incremental efficiency gains/loss with respect to its opex performance. Efficiency gain/loss is measured as the difference between the forecast opex approved (or substituted) by the AER and the actual outturn opex. Incremental gain/loss is the difference between the efficiency gain/loss of previous year and current year.

Therefore, in measuring the difference between the forecast opex and actual outturn opex of each year of the 2014-19 period, Ausgrid proposes that the actual outturn opex of each year be adjusted to account for any actuarial assessment for long service leave obligations. This is essential to ensure comparability between forecast opex allowance and actual outturn opex and hence ensure the accuracy of the calculation of the difference between forecast opex and actual outturn opex so that the efficiency gain/loss of a particular year (and the incremental efficiency gain/loss) between year is not distorted. This is critical so that the DNSP is not rewarded /penalised unduly for incompatibility between forecast opex and actual outturn opex.

Ausgrid considers our proposal on how the EBSS should operate for the 2014-19 does not negatively impact on the operation of the EBSS. Rather, we consider our proposal represents a positive clarification on the operation of the EBSS as it ensures compatibility between the numbers used to calculate efficiency gain/loss.

Capital expenditure sharing scheme

As outlined in Chapter 3.3 of Ausgrid's regulatory proposal, we do not propose any variation or departure of any component or parameters of the CESS. Hence no further response is required.

Service target performance incentive scheme (STPIS)

As outlined in Chapter 3.3 of the regulatory proposal and in Attachment 3.02 to the regulatory proposal, for the STPIS, Ausgrid proposes that a revenue at risk of ±2.5 per cent. Ausgrid does not propose any variation or departure.

Demand management incentive scheme (DMIS)

Chapter 3.3 of the regulatory proposal outlines how Ausgrid proposes the DMIS should apply for the forthcoming regulatory period. We propose a DMIS that has two components, namely:

- a DMIA component (part A of current DMIA); and
- a DMBSS component as proposed by Ausgrid.

The DMIA component is consistent with the AER's proposed approach to the application of the DMIS for Ausgrid; whilst the DMBSS is a component that Ausgrid proposes to replace the D-factor that the AER has decided to remove from the DMIS.

Attachment 3.03 of the regulatory proposal 'Application of Demand Management Scheme' outlines the reasons for the variation, how the variation aligns with the objectives of the DMIS and the impact on the operation of this scheme.

2. CLASSIFICATION OF SERVICES

2.1 Identify each proposed service classification which departs from a service classification set out in the framework and approach paper in the regulatory proposal and explain:

a) the reasons for the departure, including why the proposed service classification is more appropriate; and

b) how the treatment of the service will differ under the proposed service classification in comparison to that in the framework and approach paper.

Ausgrid does not propose any departure from the service classification set out in the AER's framework and approach paper. However, Ausgrid has noted that there are areas where we consider the AER's determination could provide more clarity on the proposed service descriptions. These matters are set out in Chapter 3.2 of the regulatory proposal and Attachment 3.01 of the regulatory proposal which contains Ausgrid's classification proposal.

2.2 If the proposed service classifications in the regulatory proposal depart from any of the service classifications set out in the framework and approach paper:

a) provide, in a second set of regulatory templates, all information required in each regulatory template in accordance with the instructions contained therein, modified as necessary, to incorporate the proposed service classifications; and

b) identify and explain where the regulatory templates differ.

Ausgrid does not propose any departure from the service classification set out in the AER's framework and approach paper.

3. CONTROL MECHANISMS

3.1 For the proposed forecast revenues that Ausgrid estimates to recover from providing direct control services over the forthcoming regulatory control period provide:

a) formulaic expressions for the basis of control mechanisms for standard control services and for alternative control services; and

b) a detailed explanation and justification for each component that makes up the formulaic expression.

These matters are addressed in the regulatory proposal at Chapters 8.4 and 9.2 of the regulatory proposal and Attachment 9.02 to the regulatory proposal   Application and demonstration of compliance with control mechanism for standard control services.

3.2 Also demonstrate:

a) how Ausgrid considers the control mechanisms are compliant with the framework and approach paper; and

b) for standard control services, how Ausgrid considers the control mechanisms are also compliant with clause 6.2.6 and part C of Chapter 6 of the NER.

These matters are addressed in the regulatory proposal at Chapters 8.4 and 9.2 of the regulatory proposal and Attachment 9.02 to the regulatory proposal   Application and demonstration of compliance with control mechanism for standard control services.

4. STEP CHANGES

4.1 For all Step changes in forecast expenditure (including those due to changes in regulatory obligations or requirements and those due to changes in Ausgrid's own policies and strategies) provide:

The term 'step change' is not a defined term in the National Electricity Rules. The AER has defined step changes in the Reset RIN as a difference in forecast expenditure from historical expenditure not attributable to forecast output growth, real price changes or productivity change. We understand that the term is to assist the AER in developing an 'alternative' opex forecast based on an approach termed 'base-step-trend' where the AER determines an annual opex forecast based on base year costs, with an adjustment for output growth, real cost escalation and step changes. This was discussed in the AER's Forecast Expenditure Assessment guidelines where it discussed the concept of step change in the context of its assessment of the opex proposed by the DNSP:

> "Step changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria.
>
> We will assess step changes in accordance with Chapter 2.2 above. Step changes should not double count costs included in other elements of the opex forecast. Step changes should not double count the costs of increased volume or scale compensated through the output measure in the rate of change. Step changes should not double count the cost of increased regulatory burden over time, which forecast productivity growth may already account for. We will only approve step changes in costs if they demonstrably do not reflect the historic 'average' change in costs associated with regulatory obligations. We will consider what might constitute a compensable step change at resets, but our starting position is that only exceptional events are likely to require explicit compensation as step changes. Similarly, forecast productivity growth may also account for the cost increases associated with good industry practice."

In our submission to the AER's draft Forecast Expenditure Assessment Guidelines we noted that the use of such a concept to exclude expenditure has the effect of precluding costs that may satisfy the criteria and factors in the National Electricity Rules. We provided examples of gaps in legitimate expenditure that are not incorporated in the AER's overall base-step-trend approach.

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

In 2013, the NSW State Government mandated the sale of Ausgrid's head office building located in George St, Sydney. As part of the sale agreement, Ausgrid will be required to lease back the building for a period of two years (with an option for a third) to enable sufficient time to relocate staff and functions to other locations. This sale is expected to be finalised by 30 June 2014 and is considered the only step change to Ausgrid's underlying operational expenditure between regulatory periods. As Ausgrid has historically owned the head office building site, it has not incurred these lease costs in the past and as such they have not been captured in the base year expenditure. Despite a temporary increase in required Opex, the proceeds of the sale will be deducted from Ausgrid's RAB value (and RAB related revenue stream) and therefore offset the impact of the step change to the consumer. Additionally, these costs will cease upon the consolidation of staff and functions to other locations and result in a more efficient cost base going forward. On this basis, Ausgrid has applied its judgement in categorising the sale of Ausgrid's head office building as a 'step change' for the purposes of the Reset RIN.

We also note that while the AER has sought information on step changes for expenditure generally, it is clear from the AER's statements above that the concept of a step change is only relevant to the AER's assessment of opex. The AER's Forecast Expenditure Guidelines does not identify a base-step-trend approach, or identify the term 'step change' in relation to its assessment of capex. In this respect, capex is not forecast in relation to an output growth factor or productivity dividend either in our capex forecast or in recent AER determinations. Indeed the AER state that its assessment approach is as follows:

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

The AER's assessment approach recognises that capex is generally non-routine in nature, and therefore cannot be determined through a base-step-trend approach that incorporates concepts such as step change, output growth or productivity changes. This view is consistent with the manner in which we have developed our total capex, which is based on a 'zero base' approach where programs are based on addressing needs in a particular year, rather than identifying particular 'step changes' from base expenditure. As such, we consider there are no 'step changes' relevant for capex, and have not addressed this in our response below.

a) in Table 2.17.1 and Table 2.17.2 (and, if Ausgrid owns any dual function assets, Table 2.17.3 and Table 2.17.4) of regulatory template 2.17, the quantum of the Step change Ausgrid:

i) forecasts to incur in each year of the forthcoming regulatory control period;

Ausgrid has completed Tables 2.17.1 and 2.17.2 in accordance with the RIN requirements.

ii) if applicable, has incurred, or expects to incur, in the current regulatory control period relative to expenditure previously approved by the AER; and

This is not applicable to Ausgrid.

b) a description of the Step change:

Refer to response to 4.2(c).

4.2 Provide an explanation of:

a) when the change occurred, or is expected to occur;

The property sale step change provided in response to 4.1, is expected to commence in July 2014.

b) what the driver of the Step change is;

The Property Sale step change is driven by Government Mandate for the sale of Ausgrid's head office building.

c) how the driver has changed or will change (for example, revised legislation may lead to a change in a regulatory obligation or requirement); and

In 2013, the NSW State Government mandated the sale of Ausgrid's head office building located in George St, Sydney. As part of the sale agreement, Ausgrid will be required to lease back the building for a period of two years (with an option for a third) to enable sufficient time to relocate staff and functions to other locations. This sale is expected to be finalised by 30 June 2014.

d) whether the Step change is recurrent in nature;

The property sale step change is non-recurrent in nature. Upon termination of the leaseback arrangement, Ausgrid staff will be fully relocated to existing premises across the network.

4.3 Provide justification for when, and how, the Step change affected, or is expected to affect:

a) the relevant opex category;

The temporary impact of leaseback costs associated with the sale of the head office building has been factored into the Property Opex category for the next regulatory period. This has been factored into the forecast from 1 July 2014 as it is anticipated that the sale will be finalised by 30 June 2014.

As part of the sale agreement, Ausgrid will be required to lease back the building for a period of two years (with an option for a third) to enable sufficient time to relocate staff and functions to other locations. The opex forecast has factored in lease costs for the first three years of the next regulatory period and site exist costs in the third year.

Additionally, a reduction in property maintenances costs associated with occupying the building has been factored in to the opex forecast from year four onwards.

b) the relevant capex category;

The step change is not expected to affect capex.

c) total opex; and

See 4.3(a), above.

d) total capex;

The step change is not expected to affect capex.

4.4 Provide the process undertaken by Ausgrid to identify and quantify the Step change; provide cost benefit analysis that demonstrates Ausgrid proposes to address the Step change in a prudent and efficient manner, including:

a) the timing of the Step change; and

Timing was determined by the State Government mandate to sell the building.

b) if Ausgrid considered a 'do nothing' option, evidence of how Ausgrid assessed the risks of this option compared with other options;

The sale of the building was mandated by the State Government as owner of Ausgrid. Analysis was provided at the time by Ausgrid and NSW State Treasury to determine the cost/benefit of the sale in comparison with maintaining the status quo (i.e. 'do nothing' option) and it was deemed appropriate to proceed with the sale.

4.5 Provide, if the Step change is due to a change in a regulatory obligation or requirement:

a) relevant variations or exemptions granted to Ausgrid during the previous regulatory control period or the current regulatory control period;

b) relevant compliance audits Ausgrid conducted during the previous regulatory control period or the current regulatory control period;

The step changes provided in response to 4.1 are not due to changes in regulatory obligations or requirements.

4.6 with reference to specific clauses of the relevant legislative instrument(s), the:

i. previous regulatory obligation or requirement; and

ii. changed regulatory obligation or requirement that is driving the Step change.

Ausgrid has provided details of the relevant legislative instruments in the response to 4.2(c), above.

5. CAPITAL EXPENDITURE

General

5.1 Provide justification for Ausgrid's total forecast capex, including:

a) why the total forecast capex is required for Ausgrid to achieve each of the objectives in clause 6.5.7(a) of the NER;

We have articulated how our total forecast capex for Standard Control Services are to achieve each of the capex objectives in clause 6.5.7(a) of the National Electricity Rules in Attachment 5.31 - Addressing the capex and opex objectives, criteria and factors , Attachment 5.32 - Economic Interpretation of clauses 6.5.6 and 6.5.7 of the NER (Meaning of prudency and efficiency) and Attachment 5.33 - Addressing the benchmarking factor for capex and opex (including Huegin, Evans & Peck, Repex and Augex) of Ausgrid's regulatory proposal.

b) how Ausgrid's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER;

We have articulated how our total forecast capex for Standard Control Services are to achieve each of the capex criteria in clause 6.5.7(c) of the National Electricity Rules in Attachment 5.31 - Addressing the capex and opex objectives, criteria and factors , Attachment 5.32 - Economic Interpretation of clauses 6.5.6 and 6.5.7 of the NER (Meaning of prudency and efficiency) and Attachment 5.33 - Addressing the benchmarking factor for capex and opex (including Huegin, Evans & Peck, Repex and Augex) of Ausgrid's regulatory proposal.

c) how Ausgrid's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER;

We have articulated how our total forecast capex for Standard Control Services are to achieve each of the capex factors in clause 6.5.7(e) of the National Electricity Rules in Attachment 5.31 - Addressing the capex and opex objectives, criteria and factors , Attachment 5.32 - Economic Interpretation of clauses 6.5.6 and 6.5.7 of the NER (Meaning of prudency and efficiency) and Attachment 5.33 - Addressing the benchmarking factor for capex and opex (including Huegin, Evans & Peck, Repex and Augex) of Ausgrid's regulatory proposal.

d) an explanation of how the plans, policies, procedures and regulatory obligations or requirements identified in regulatory templates 7.1 and 7.3, and consultants reports, economic analysis and assumptions identified in 1.5 have been incorporated; and

In Attachment 5.31 of Ausgrid's regulatory proposal we have identified how the suite of supporting documents in our proposal have been instrumental in developing our total capex forecast, and how these documents are relevant to the AER's decision on whether to accept or reject Ausgrid's proposed capex under clause 6.5.7 of the National Electricity Rules. The supporting documents include, but are not limited to, the categories of material identified in the AER's questions, and we refer the AER to the entire list of documents we have submitted in support of our capex forecasts in our regulatory proposal. We have addressed each element of the AER's questions below.

Plans

Ausgrid has used a series of capital plans used to derive the proposed capex. Each of the capital plans have been summed together to derive the total capex forecast for the 2014-19 period. Chapter 5.3 of our regulatory proposal identifies each plan, and we note that there is a series of supporting documents termed "Overviews" that explain previous expenditure, future circumstances, forecast methodology and description of projects and programs within the capital plan.

In Attachment 5.31 we identify how our approach to use capital plans results in a total capex that addresses clause 6.5.7 of the National Electricity Rules. In particular, we note that:

- Each capital plan relates to a driver of expenditure that aligns to the capex objectives in the National Electricity Rules.
- A key feature of our planning approach is that there is a clear demarcation between the projects and programs of work in each capital plan. This type of planning approach ensures there is no overlap or gap in our expenditure requirements.
- When developing our individual plans, we have considered the most appropriate and cost effective way to estimate our requirements.

- A key element of each of our capital plans is a consistent and appropriate method for identifying investment need, and a rigorous approach to selecting of the most efficient option to address the need.

Regulatory obligations

When developing our capital plans, we identify the investment required to meet our regulatory obligations to provide safe and reliable services. Our key regulatory obligations and requirements have been identified in Template 7.3 of the regulatory templates provided as part of this response to the RIN.

Regulatory obligations influence when we need to incur expenditure. As an electricity provider, we are subject to a range of industry specific obligations regulations that set out the manner in which we supply electricity in the Australian National Electricity Market. These regulations include the Electricity Supply Act 1995 (NSW) and Regulations made under it, the National Electricity Law (NEL) and National Electricity Rules and the National Energy Retail Law and Rules. For example:

- The Electricity Supply Act imposes requirements to hold DNSP licence which in term imposes conditions with respect to reliability and performance of the network. The Electricity Supply (Safety and Network Management) Regulation imposes requirements in relation to the preparation and implementation of network management plans addressing network safety and reliability, customer installation safety, public electrical safety as well as bushfire risk management.

- The National Energy Retail Law and Rules introduced in NSW from 1 July 2013 imposes requirements in relation to connecting customers, customer connection contracts, guaranteed customer service standards and a range of customer rights and protections including notification of planned interruptions, disconnection processes and managing customer complaints. .

- The NEL and Rules regulate Ausgrid's participation in the National Electricity Market as a Network Service Provider (both and TNSP and DNSP) and cover a range of matters including system and network reliability and security, network planning, connections procedures, and system and network standards.

Ausgrid is also subject to more general obligations and requirements which direct the way we design and operate the network. These obligations are mainly concerned with environmental protection, and public and worker safety. These influence our drivers of investment, for example, we may replace an asset if the safety consequences to our workforce or the general public cannot be appropriately mitigated through maintenance. The standards also influence our construction and designs, for instance by adhering to environmental, planning and heritage legislation.

In addition to our key role of providing electricity services, we are also required to meet our obligations as a corporation in respect of corporate governance and financial accountability. These can drive the need for investment in IT and financial systems, and non-system property to house staff performing these functions. Further, as a state owned corporation, we are subject to specific legislation in respect of performing our functions. An example is the NSW State Records Act (1998) requirement to maintain records, which necessitates IT systems that record and maintain information.

As a prudent DNSP, Ausgrid also adheres to codes and guidelines that provide direction on how to meet our overriding obligation[1] to operate our network in accordance with good electricity industry practices. For example, under our Network Management Plan we adhere to guidelines on safety clearances, working in enclosed spaces, and network configuration on high bushfire risk days. Often these programs will influence our decisions to invest in replacing an asset, or on the construction standard that we apply.

Policies, procedures and strategies

Template 7.1 of the regulatory templates has identified each of the types of policies, procedures and strategies that we have at Ausgrid. These strategies influence planning approaches and expenditure decisions we make at Ausgrid, and has been pivotal to the manner in which we have developed our capex forecasts for the 2014-19 period.

Corporate planning documents

Ausgrid has a number of corporate planning documents that provide vision and objectives on how to meet our regulatory obligations in an efficient and prudent manner. Under industry reform, the NSW DNSPs now have a common set of corporate strategy documents to ensure that our capital and operating forecasts meet our primary corporate objectives of safety, affordability and reliability. These strategies are summarised in the document, "Delivering efficiencies for our customers" and include:

[1] See for example clause 5.2.1 of the National Electricity Rules which requires all registered participants to maintain and operate their facilities in accordance with relevant laws, the requirements of the rules and good electricity practice and relevant Australian Standards

- The customer value plan – Sets a vision for future engagement with customers to ensure best value for money for the services we provide. The strategy has impacted the development of our proposal in 2 fundamental ways. It has focused our programs on identifying efficiencies in our costs so as to meet our goal of affordability, and has re-focused the business on engaging with our customers on issues such as levels of reliability and safety that we should strive for.

- The safety strategic plan – The objective is to protect the safety of the public, our employees, our contractors and those who are influenced by our business undertakings. Our long term business success depends on our ability to continually improve the quality of our services while protecting people and the environment. The safety plan is a key influence on our asset replacement programs where we have sought to find efficient ways to maintain the safety of the network despite deterioration in asset condition on the network.

- Asset Management Strategic Plan Effective asset management is the key to being able to safely and efficiently deliver a reliable and sustainable electricity network, while continuing to promote customer affordability. The plan has focused on ways to prudently defer replacement of assets in the period, through activities such as the prioritisation process.

- The Risk Management Strategic Plan - Aims to embed a common Risk Management Framework across the Network companies, and accordingly provide a common basis for making decisions such as levels of investment to mitigate risk.

- Technology Strategic Plan The objective is to leverage technology, enable the business' transition to a more efficient business model, and to facilitate delivery of the new business model's objectives. The plan's scope includes information technology and telecommunications, as well as operational and grid technologies. This plan has enabled us to deliver significant reductions in our technology costs over the next period.

- The Human Resources Strategic Plan – This sets a blue-print on how to transition to efficient workplace change and structural reform introduced under industry reform, and to promote efficient leadership and performance across the business. This plan has been instrumental in shaping our expected expenditure related to implementing efficiency reforms such as the Network Reform Program and the prioritisation process.

- The Finance Strategic Plan The objective is to manage the financial health of the three NSW distribution networks in a manner that protects financial value and delivers balanced outcomes for both customers and the shareholder. This has influenced our decisions on levels of capex, and on proposing a rate of return that is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk.

Governance frameworks

Ausgrid has a well documented investment governance framework which sets out the process by which network capital investments are made and implemented within Ausgrid. The governance process ensures that projects planned through the network planning process continue to represent an optimal investment solution in light of current circumstances.

In this respect we note that our capex forecasts have been through appropriate checks and balance as part of this governance framework, and provide a level of assurance that programs will proceed in the next period in an efficient and prudent manner. Key documents which demonstrate our governance frameworks include:

- Board Policy Governance Policy This provides a robust system of governance addressing, but not limited to: integrity and efficiency of support to the Board in its roles and functioning and in its relationship with relevant Ministers; integrity and efficiency of support to the Board Committees in their roles and functioning; risk management and compliance with statutory requirements; disclosure, transparency and liaison with shareholders and stakeholders; and implementation of the company's strategy and directions through the company and business planning, resourcing processes, business systems, policies, procedures and performance monitoring.

- Board Policy Delegation of Authority - This Delegations Policy sets the framework for managing delegated authority throughout the company by the board of directors to support effective decision making. The delegations framework consists of: the Delegations Policy; the Instrument of Delegation of Authority to the CEO (A Deed which documents the written authority of the CEO granted by the board under this Policy);

the Sub-delegations Policy and Schedules (a document under which CEO sub-delegates to employees within the company); and board approved Power of Attorney.

- Executive Leadership Team Charter - The Ausgrid Executive Leadership Team (ELT) Committee provides a forum for the ELT to review and endorse strategic and operational decisions on important matters that affect the Company.

Ausgrid's capex approval processes also demonstrate that we have an effective governance process underlying our investment decisions. The Network Project Approval process and record delegated authority for projects and sub-programs. Projects and programs proceed through the planning to delivery stage with appropriate checks and balances on costing scope and delivery. For example, the development brief is an instruction issued from Chief Engineer to commence development of a project that is required as part of an area plan or replacement plan, and is supplemented with information on critical dates, costs and technical details.

Asset Management

Ausgrid's Network Asset Management Strategy has significantly shaped the decisions underlying Ausgrid's proposed replacement and maintenance expenditure for the 2014-19 period. The document provides an overall view of the approach Ausgrid takes to manage its asset portfolio to achieve business objectives. It describes the key business objectives, and relates them to the key target outcomes of the asset management processes. It describes the nature of the Ausgrid asset base at a high level and the policy level approach to asset management. It describes the key processes in the asset management framework by reference to the appropriate policy, standard and procedural documents.

Network planning and standards

Our network planning documents have been a crucial influence on the development of our capex forecasts for the 2014-19 period. They influence our decisions on when to invest, and the most efficient option to address the need taking into account safe working practices and meeting good electricity industry practice in design and construction.

Ausgrid has a series of policy documents that set out our principles for investing on the network. For example, our investment network policy defines the principles and approach by which Ausgrid decides to invest in its electricity system. The document identifies the legislative requirements and investment objectives, decision making processes and criteria, and processes to ensure these decisions are made in a consistent and transparent manner. Ausgrid also has a specific policy document relating to the principles and objectives of reliability of supply.

Our investment standards provide more detail on key aspects of our policy documents. This includes:

- The process we use to derive the programs and projects underlying each of our capital plans. For example, we have an investment standard for our Area Plans, Replacement planning, low voltage planning, and reliability planning.
- Spatial demand forecast process.
- Ratings and impedance standards for planning the capacity of our assets when making investment decisions.
- Configurations of network designs.

We also have a series of detailed standards which set out specific designs and activities that underlie our costs structures. Electrical standards mostly relate to information we provide our stakeholders on topics such as specifications for connecting to our network. Network standards set out specification for designs and construction standards for instance the design criteria for low voltage kiosks. In effect these provide additional instructions on the high level guidance provided in investment standards. Technical standards relate to work practices including qualifications and experience for working safely on the network. For example, the technical standard for underground cable work details the qualifications required for personnel, together with a set of safe working practices for construction, maintenance or operating work on or associated with underground cables.

Other policies, procedures and strategies

Template 7.1 also requests information on specific categories of procedures and strategies that impact our expenditure. In the section below we provide a brief summary of how these strategies have influenced the derivation of the total capex forecast for the 2014-19 period.

- Demand management - This policy provides an overview of Ausgrid's approach to the investigation and implementation of demand management solutions. This includes pilots and trials under the DM Innovation

Allowance, targeted DM projects to defer specific network augmentation capital projects, and broad-based DM programs to reduce peak demand in broader network areas. This has been a key framework for developing forecasts of DM expenditure and the consequent reductions in capex as part of our 2014-19 forecasts.

- Asset security and disaster recovery These policies ensure that Ausgrid keeps its assets safe from sabotage and can continue to provide services in the event of disasters. In the absence of these policies, Ausgrid's capex could be of a far higher magnitude over the 2014-19 period.
- Accounting and procurement policies These provide assurance that we capture and record costs we incur on the network in accordance with accounting standards. These have been instrumental in ensuring that our forecasts have allocated costs properly to standard control services, and that the cost relates to a capex rather than opex activity. For example our capitalisation policy provides clear guidance on what constitutes expenditure of a capital nature.
- Procurement policy and manual This document sets out minimum standards for the procurement of goods, stores, materials, equipment, works and services as well as the disposal of obsolete or surplus goods, stores, materials and equipment. It ensures that Ausgrid seeks all opportunities to efficiently reduce the capital costs we incur in providing services, through practices such as securing the lowest rates on electrical equipment.
- IT policies – IT policies provide guidance on the systems that are required to ensure that we continue to provide support to meet our network and corporate functions in an efficient manner. For instance, the IT capital approval process defines the process for all projects so as to utilise maximum benefits and ensure budgetary control. In recent times we have introduced other polices such as the Benefits Management Framework that set out a clear process for realising the benefits of IT projects that were implemented to achieve efficiencies in the business.

Economic analysis

Section 1.5 of our response identifies the suite of documents we have submitted in our regulatory proposal that we consider meets the AER's definition of economic analysis. We noted that there are 3 broad types of economic analysis that we have provided to the AER in support of our forecast capex. In the sections below, we show how these are relevant to demonstrating that our 2014-19 forecast is efficient and prudent.

Economic analysis methodology

Ausgrid has a well defined methodology for undertaking economic analysis (see Investment Standard - Performing economic appraisal of investments) when identifying capital forecasts. This methodology has applied consistently to each capital plan to develop Ausgrid's capital forecasts for the 2014-19 regulatory period.

The document provides a guide on how to undertake options assessment so as to identify the least cost/ maximum benefit project. In applying the methodologies we have used best practice techniques such as Net Present Value analysis and identification of market benefits to justify the selected option.

Investment cases

Investment cases and models relate to capex programs and projects being proposed for the 2014-19 period, which draw upon the economic analysis methodology outlined above.

Investment case material is particular to the nature of the planning approach used in each capital plan. For instance there are 28 Area Plans that provide strategic options, which are accompanied by more detailed options assessment. The investment cases for replacement plans are called Asset Condition and Planning documents (ACAPs), and contain information on particular technology types. For 11kV, low voltage and customer connections, the case for investment is based on granular models which take into account the local circumstances underlying our network. For non-system property and technology, the material is referred to as a business case.

Investment cases are important in assessing our capex proposal as they provide the detailed evidence underlying the need of the project, and demonstration that the most economically efficient project has been selected to address the need. As such, we consider that the probative value of these materials to the AER's assessment is exceptionally high, and will be more precise than using high level tools such as benchmarking or predictive models that fail to take into account our unique circumstances. In effect, they provide the AER with the ability to understand whether our forecast process has been applied appropriately, and that the project is needed and is efficient in our circumstances.

Costing programs of work

A crucial element of our investment cases is an accurate estimate of the efficient costs of undertaking the project in our circumstances. We consider this is vital in demonstrating that the most efficient option has been selected, and that the costs are efficient and prudent in our circumstances. Costing methods also involve an estimation of changes in costs over time as a result of real cost escalation, and therefore are important in demonstrating that cost projections are a realistic expectation of the costs of undertaking projects.

Ausgrid has provided evidence that our overall costing methodology is sound for each element of our program. For instance, for major projects in the Area Plans, we have relied on approaches that take into account site specific factors such as the route complexity. For cases where there are a large number of projects, we have used approaches that identify the relative complexity of the expected project on average, and developed our costs on this basis.

In addition, we have provided details on how unit costs for each project or program of work were derived, and as such, can satisfy the AER as to the source and accuracy of our costing methodologies.

Assumptions

A key element of a prudent forecasting approach is the consideration and adoption of realistic assumptions that impact the total forecast capex. In Table 9 we show how each assumption has been important to developing our proposal.

Table 9 How assumptions impacted capex forecasts

No.	Key Assumption	How assumption impacted our capex forecasts
1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.	This has been important in identifying the nature of investment we are required to undertake in our role as a DNSP. Our current organisational structure is also important in understanding deliverability of the capex program.
2	The capital program has been prepared on the basis of amendments to the NSW Reliability and Performance Licence Conditions that will come into effect on 1 July 2014.	The removal of Schedule 1 of the licence conditions means that Ausgrid does not have deterministic criteria for investing in the security of the network. This has provided opportunities to defer capacity investment where we determine a prudent level of risks could be tolerated. Despite this, opportunities are limited given that we still need to maintain reliability performance standards, and that spot loads rather than organic growth are driving capacity investment. We note that Schedule 2 and 3 which relate to average and individual feeder reliability are consistent with the licence conditions in place for the 2009-14 period, and that our reliability compliance plan has used this as a basis for identifying investment when we forecast that we cannot meet the standards in the 2014-19 period.
3	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.	Prioritisation of the program under the strategic management framework has significantly reduced the total capex proposed by Ausgrid. Further information on the prioritisation can be found in the document, “Delivering Efficiencies for our Customers”.
4	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.	This has impacted the level of capacity expenditure we have proposed for the Area Plans and the Distribution Capacity Plans, including proposed SCS capex on connecting new customers to the network.

No.	Key Assumption	How assumption impacted our capex forecasts
6	Forecast internal labour costs and wage rate increases have been set consistent with our Enterprise Bargaining Agreement (EBA) for the extent to which this applies, and that forecasts from that point on have been set based on data provided by Independent Economics.	This has impacted our forecast costs of delivering the capex program, as escalation has been applied to each program/ project in our total forecast capex.
7	The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.	This is not relevant to our capex proposal.
8	Ausgrid has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.	Chapter 1 of our regulatory proposal, and the underlying supporting documents show the activities we undertook in engaging customers on a range of issues including reliability, price, construction and design standards, metering technology, demand management and energy efficiency, support for vulnerable households, and communication and engagement. Our research findings can be found in supporting documents. The findings in some of these areas support the basis of our proposed total capex on price, reliability levels, safety and construction standards. Further information can be found in the Attachment: Addressing the Rules for capex and opex.

Consultants' reports

Consultants' reports provided expert advice on inputs or methodologies to develop our capex proposal, and also provided assurance or checks on the efficiency and prudency of the forecasts. We consider that consultant reports identified in question 1.5 should be taken into account by the AER in its assessment of our forecast capex under clause 6.5.7 of the National Electricity Rules. In particular:

- We consider that external assurance reports confirm accuracy and reliability of data, for example assurance reports on our BPC model. This is further discussed in our response to question 5.2(c) where we demonstrate that the review provides additional assurance that our final forecasts are free of error.
- The advice on key inputs used to develop forecasts, for example real cost escalation. Receiving this advice from economic experts provides an independent view on the level of escalation expected in the 2014-19 period that impact our costs of delivering the capex program.
- Reviews of our inputs, program/ projects or total expenditure which provides advice on our forecasts, for instance reviews of our demand forecasting methodology provides independent verification of our methodologies.
- Advice on how to prepare forecasts, or provide evidence in accordance with the National Electricity Rules, for example advice on economic interpretation of the National Electricity Rules for capex and opex. This has enabled us to identify the key evidence that we should submit to the AER to address the capex objectives, criteria and factors in the National Electricity Rules.
- Review of past performance, for example a review of capex and opex outcomes in the 2009-14 period. This provides independent advice on reasons for variation on previous forecasts.

e) an explanation of how each response provided to paragraph 5.1 is reflected in any increase or decrease in expenditures or volumes, particularly between the current and forthcoming regulatory control periods, provided in regulatory templates 2.1 to 2.12.

We understand that the purpose of this question is to identify changes in expenditure between the current and future period. We have explained past and future trends in capex investment in Chapter 5 of our regulatory proposal (see Chapter 5.1 and 5.2). The review of outcomes for the 2009-14 regulatory period document prepared by Arup Consulting also provides further information on past and future trends in capex by the types of categories in the AER's RIN templates, provided in Attachment 5.01 review of outcomes for the 2009-14 regulatory period. Finally, the document titled, "Addressing the capex and opex objectives, criteria and factors" addresses capex factor 4 of 6.5.7(e) of the National Electricity Rules, which relates to actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods.

Below we have provided a summarised version of the comments we have made in these documents that specifically addresses the AER's question. The key observation is that our forecast capex is far lower than actual capex for 2009-14. This reflects that we achieved considerable improvements in the security of the network in the 2009-14 period under new licence conditions, and that we can return to more steady state levels of investment in this period. The lower proposed amount also reflects the efficiencies achieved under industry reform, with a primary focus on affordability through striving to contain average increases in our share of customers' electricity bills at or below CPI.

In terms of trends in actual capex since 2009-10 through to expected and forecast 2014-19 period, we identify four key points:

- The large investment program in the early years of the 2009-14 period was in response to significant under-investment in the past. Ausgrid's assets were aging at a rapid rate as a result of low replacement allowances, and utilisation levels on our assets were too high to maintain an adequate and secure level of supply. In response to these conditions, the NSW Government required us to meet new licence conditions relating to security standards and reliability performance. At the same time, we recognised that a significant increase in replacement was required as a result of asset degradation on the network.

- While investment increased rapidly in the early years of the period (2009-10 to 2011-12), Ausgrid spent less than the forecast allowance. This was a result of delivery issues, particularly with large projects. Given these delays, Ausgrid re-orientated its capex to ensuring delivery of large sub-transmission projects, and projects to meet our licence conditions. Expenditure in distribution and replacement fell as a consequence.

- From 2012-13 onwards, Ausgrid's capital program declined significantly. This reflected that we were starting to return to a steady state of investment, after investing considerably in the early years of period in capacity to meet the new licence conditions. Further, a reduction in peak demand allowed us to further reduce capex. The decline in expenditure in the latter years of the period largely reflected strategic re-orientation of the business as a result of industry reform, with a greater emphasis on affordability of prices for customers. As part of this strategy we re-visited our risk acceptance thresholds in an effort to better target our risk mitigation strategies, put in place effective cost controls including seeking more information before approving a project through our internal governance process. The thorough review of processes has also caused delays in the delivery of large projects which are now being proposed in the initial years of the 2014-19 period.

- The capex forecast for 2014-19 seeks to maintain the downward step change in capex as a result of the capital reduction strategy implemented in the latter two years of the current regulatory period. Chapter 5.2 of our proposal identifies the drivers of expenditure that are driving the trend of capex in the 2014-19 period including:

    - We are proactively responding to the hardship faced by our customers by identifying opportunities to defer capex and implement efficiencies. This continues the reforms introduced in the last 2 years of the current regulatory period where we tried to find efficiencies to reduce the price paid by customers in the next period. This in particular explains large reductions in total capex overall, and for non-system expenditure identified in the regulatory templates.

    - We still have a large number of old assets on our network. While we made strong inroads into arresting condition issues on the transmission network, the condition of assets on the distribution network has continued to deteriorate. This explains increases in replacement expenditure between the 2009-14 and 2014-19 regulatory periods.

- ○ The backlog in investment to meet new security under licence conditions imposed in 2007 has been largely completed. Further, peak demand has continued to be largely flat. This reflects reduced spend on augmentations over the period, although we expect customer numbers to be higher over this period. Despite lower levels of augmentation, a key feature of our network is that localised growth and customer connections result in the need to invest in capacity on certain parts of our network. The change in the NSW Licence conditions to apply for the 2014-19 period has provided opportunities to prudently defer investment. Despite this, opportunities are limited given that we still need to maintain reliability performance standards, and that spot loads rather than organic growth are driving capacity investment.

5.2 Provide the model(s) and methodology Ausgrid used to develop its total forecast capex, including;

Table 10 below identifies documentation that relates to models and methodologies used to develop our total capex forecast for standard control services. The key categories of documents are:

- Overviews of our capital plans – These set out the methodology we have used to derive the proposed forecast for each capital plan, including high level description of models when these have been applied.
- Models used to derive forecast capex for a capital plan – In some cases, we have used a modelling approach to derive the proposed capex for a capital plan such as for the 11kV, low voltage and customer connections. These models include explanatory information setting out the methodology and sources underlying these models.
- Underlying inputs that rely on models Key inputs such as peak demand forecasts and customer connections rely on modelling approaches. These models include explanatory material setting our methodology and sources underlying these models.

Documents which fit within these categories have been identified in Table 10, and can be found in the material we have provided as part of our regulatory proposal.

Table 10 Documentation in Ausgrid's regulatory proposal that relates to total (SCS) capex forecast models and methodologies

Attachment number/ supporting document reference	ID	Deliverable
5.03	ID33697	Spatial demand forecast by zones and substations
5.04	ID65078	(INV-STD-10022) Planning Standard - Demand Forecast & related documents
5.10	ID45457	Approved CAM
5.15	ID78779	Overview of the unit cost methodology
5.16	ID36536	Overview of the cost escalation methodology
5.17	ID35107	Cost escalation inputs and model
5.18	ID94028	Independent economics - Labour escalation for NSW DNSPs

Attachment number/ supporting document reference	ID	Deliverable
5.19	ID04288	CEG - Material escalation for NSW DNSPs
5.23	ID94035	Overview of the Area Plans for 2014/15 to 2018/19
5.24	ID00366	Overview of the Replacement and Duty of Care Plans for the 2014-15 to 2018-19
5.25	ID37770	Overview of the Distribution Capacity Plan for the 2014-15 to 2018-19
5.26	ID18205	Overview of the Reliability (Compliance) Plan for 2014-15 to 2018-19
5.27	ID96634	Overview of the Technology Plan for 2014-15 to 2018-19
5.28	ID92188	Overview of non-system property capex and opex for 2014-15 to 2018-19 period
5.29	ID59850	Overview of fleet capex for 2014-15 to 2018-19
5.30	ID07004	Other capex - forecast & explanation (plant & tools)
Supporting Ch 5	ID00074	(INV-STD-10024) Planning Standard - Economic Appraisal
Supporting Ch 5	ID90027	SKM review of Ausgrid's peak demand forecast method
Supporting Ch 5	ID00070	Capitalised wages - GIS data operations, system control and network planning
Supporting Ch 5	ID68852	Customer number forecast methodology
Supporting Ch 5	ID32532	Customer number forecasts model
Supporting Ch 5	ID50783	EY Audit report of Ausgrid's BPC models
Supporting Ch 5 - Area plans	ID75799	Conditional Projects
Supporting Ch 5	ID97884	Risk Quantification Methodology

Attachment number/ supporting document reference	ID	Deliverable
Supporting Ch 5	ID07366	Replacement & Duty of Care Plan (distribution projects) unit cost methodology
Supporting Ch 5	ID33420	Replacement & Duty of Care Plan unit costs
Supporting Ch 5	ID50068	11kV model: Method and Outcomes of DND (explanatory)
Supporting Ch 5	ID21349	DND (11kV) model
Supporting Ch 5	ID60868	Low Voltage capex model: Method and Outcomes (explanatory)
Supporting Ch 5	ID56211	LV volumes model
Supporting Ch 5	ID92279	LV cost of delivery table
Supporting Ch 5	ID81882	Customer connections capex model: Method and Outcomes (explanatory)
Supporting Ch 5	ID97008	Customer connections model: volumes
Supporting Ch 5	ID70090	Customer connections cost of delivery table
Supporting Ch 5	ID68195	Feeder Category Reliability Forecast System Methodology
Supporting Ch 5	ID33258	Feeder Category Reliability Forecast System (spreadsheet)
Supporting Ch 5	ID96854	Reliability CAPEX Forecast calculation
Supporting Ch 5	ID17472	Technology Plan costing methodology and estimates

a) A description of how Ausgrid prepared the forecast capex, including:

We refer the AER to Chapter 5.3 of our regulatory proposal, where we have documented our methodology (including modelling approaches) underlying the preparation of our capex forecasts. We note that further information on our methodologies is contained in each of the Overviews for the capital plans (attached to our regulatory proposal) including:

- The Area Plan Overview (Attachment 5.23 Overview of the area plans for 2014-19)

- The Replacement and Duty of Care Overview (Attachment 5.24 Overview of the replacement and duty of care plans for 2014-19)
- The Distribution Capacity Plan Overview (Attachment 5.25 Overview of the distribution capacity plan for 2014-19)
- The Reliability Plan Overview (Attachment 5.26 Overview of the reliability (compliance) Plan for 2014-19)
- The Technology Plan Overview (Attachment 5.27 Overview of the technology plan for 2014-19 [CONFIDENTIAL])
- The Corporate Property and Fleet Overview (Attachment 5.28 Overview of non-system property capex and opex for 2014-19)

i) how its preparation differed or related to budgetary, planning and governance processes used in the normal running of Ausgrid's business;

Our budgetary, planning and governance processes continually evolve over time, and this has been particularly so since the strategic re-alignment process of NSW DNSPs as a result of industry reform. As part of this strategy we considered how best to apply our budgetary, planning and governance processes to improve customer affordability. This included deeper consideration of risk thresholds when developing our replacement and capacity programs, more stringent cost controls before approving a project through our internal governance process, and identification of efficiencies. To give effect to these changes, we have continually evolved our budgetary, planning and governance processes and these have influenced the development of our capex forecasts for the 2014-19 period.

The re-alignment of strategies under industry reform had the effect of greatly reducing levels of capex in the latter 2 years of the current period. The 2014-19 forecasts have also been developed with prudent deferral and efficiencies in mind, taking into account the learnings of the last 2 years of the current regulatory period.

A key factor that has influenced the preparation of our total capex forecast for 2014-19 is a change to the Investment Governance Framework in 2013, which now applies consistently across the 3 NSW DNSPs. An important element of the new governance framework was a formalised process for prioritising investments, which has assisted us to develop a capital program that represents a prudent risk level.

As such, our investment governance framework sought to apply a prioritisation method that helps us to balance these objectives when finalising the capex proposals for the 2014-19 period. The process used was as follows:

- We developed capex proposals based on our existing processes at Ausgrid. This already incorporated the refinements we had been making to our budgetary, planning and governance processes.
- Networks NSW was provided with a list of all projects and programs. Each project or program was assigned a risk ranking, based on a consistent methodology for assessing risk. The consistent application of a single approach allowed us to objectively rank projects across the businesses in a consistent way.
- Based on a holistic review of acceptable risk, Networks NSW was able to identify the total risk from different prioritisation scenarios, and to identify a level that enabled us to take on a prudent level of risk in our circumstances.

ii) the processes for ensuring amounts are free of error and other quality assurance steps; and

Ausgrid notes that we have used an internal assurance process when developing our capital plans for the 2014-19 regulatory proposal. This involves appropriate peer review, and assurance from the responsible Executive that all calculations and modelling are arithmetically correct in all material aspects and capable of replication.

This has been complemented by an independent review on the model that consolidates all the information in the capital plans. The Business Planning and Consolidation Model (BPC) is a model that identifies the quantity and price of each program or project in Ausgrid's capital plans. We engaged Ernst and Young to review the technical (ie: functionality and formula) of BPC, and also to check that the inputs are arithmetically correct to derive the total capex for each year of the 2014-19 regulatory control period.

Further, Ernst and Young have reviewed the real cost escalation model that is imputed into BPC, and verified that the BPC outputs have been correctly inserted into the Post Tax Revenue Model.

iii) if and how Ausgrid considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.

Ausgrid considers that the capex forecasts meets the National Electricity Objective in the National Electricity Law which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system.

When developing our capex proposal, we have considered 3 underlying objectives including safety, reliability and affordability of our standard control services, each of which meet the definition of long term interests of customers as expressed in the NEL. We discuss each below.

In respect of safety, our overarching objective is to continuously improve our safety performance for employees, contractors and the public. We consider that this meets the long term interests of customers as it ensures that customers and the general public are not harmed when assets fail in service, or do not meet modern day standards. We meet safety by investing in replacement and duty of care programs, and the resultant expenditure is contained in our Area Plans and Replacement and Duty of Care Plans. We also note that this objective is aligned to Capex Objective 4 under 6.5.7(a) of the National Electricity Rules, which is to maintain the safety of the distribution system through the supply of standard control services.

Our customer engagement activities have also provided further evidence to demonstrate that customers support us maintaining current safety levels. A key finding of our engagement activities was that customers expected that electricity was supplied in a safe manner and believed that this should be taken into account when constructing and operating the network.

In terms of reliability, our objective has been to ensure the on-going reliability, security and sustainability of the network. We consider this meets the long term interests of customers by maintaining the security of services in the 2014-19 period that customers received in the current regulatory period, and by ensuring that we continue to meet our reliability performance targets. We also note that this is consistent with Capex Objective 2 and 3 under 6.5.7 of the NER.

Our engagement activities with customers have further provided evidence that maintaining reliability is consistent with the long term interests of customers. We have listened to the views of our customers by not increasing or improving beyond our current standards.

Our third objective is customer affordability through striving to contain average increases in our share of customers' electricity bills at or below CPI. This meets the price element of meeting the long term interests of customers. Our means of delivering affordability to customers has been through the efficiency initiatives we have implemented under industry reforms. These efficiencies have been articulated in Attachment 1.01 - NNSW - Delivering efficiencies for our customers. We consider that the pursuit of efficiencies including prudent deferrals of capex is consistent with the capex criteria under 6.5.7(c) of the National Electricity Rules including the efficient costs of achieving the capital expenditure objectives and the costs that a prudent operator would require to achieve the capital expenditure objectives.

We also note that customer affordability is consistent with the results of our customer engagement strategies. A significant number of our customers had seen increases in their electricity bills over the past few years. Customers understood the need to spend money to maintain the electricity network. However, there was a clear preference that if prices needed to increase, they should do so in a steady manner over a number of years rather than a one-off "bill shock".

b) any source material used (including models, documentation or any other items containing quantitative data): and

The documents identified in 5.2 above include information on source material and quantitative data.

c) all calculations that demonstrate how data from the source material has been manipulated or transformed to generate data provided in the regulatory templates.

This information has been provided in the Basis of Preparation for the respective RIN templates or model documentation in relation to capex.

5.3 Identify which items of Ausgrid's forecast capex have been:

a) derived directly from competitive tender processes;

b) based upon competitive tender processes for similar projects;

c) based upon estimates obtained from contractors or manufacturers;

d) based upon independent benchmarks;

e) based upon actual historical costs for similar projects; and

f) reflective of any amounts for risk, uncertainty or other unspecified contingency factors, and if so, how these amounts were calculated and deemed reasonable.

Reliability Capex

The reliability capex component of Ausgrid's forecast capex has been derived using actual historical costs for similar projects completed by Ausgrid.

Fleet plan Capex

Ausgrid separates the expense elements of fleet capex into two categories:

- Fleet Replacement Plans;
- Fleet Refurbishment Plans;

Each expense element of fleet capex is derived using a number of the different methods outlined in 5.3, including combinations of methods.

For Fleet Replacement Plans the major elements are:

- Contracted Services
- Materials

For contracted services, Ausgrid has previously adopted a competitive tendering process to pre-select panels of preferred contractors for these works. Historical costs from previous procurements have been used to formulate estimates.

For material costs, Ausgrid's estimates have been prepared using current manufacturers and suppliers period contract prices for major fleet categories, such as vans, trucks and other vehicles. Ausgrid also uses NSW Government Supplier Contracts for available vehicle categories– these costs are derived from costs updated quarterly in NSW Procurement system.

For Fleet Refurbishment Plans the major elements are:

- Contracted Services

For contracted services, Ausgrid has previously adopted a competitive tendering process to pre-select panels of preferred contractors for these works. Historical costs from previous procurements have been used to formulate estimates. Currently a competitive tendering process is being conducted by Network NSW to deliver these services. Upon completion of the procurement exercise, these costs will form basis of refurbishment plans.

In preparing its estimates for fleet capex, Ausgrid has made no allowance for risk, uncertainty or contingency (5.3(f)).

Distribution capacity Capex

Distribution capacity capex is comprised of three component capex plans:

- 11kV plan
- Low voltage plan
- Customer connections plan

Forecast capex unit costs for Low voltage and Customer connections capex plans have been derived using historical completed projects ((e) above).

For the 11kV capex plan, unit cost components are based on Ausgrid's standing contracts which were subject to a competitive tender process ((a) above).

Non-System Property Capex

Ausgrid cost elements for non-system property capex comprises mostly of contracted services.

For contracted services, Ausgrid has adopted a competitive tendering process to select preferred contractors for these works. Additionally, Ausgrid's cost estimates for contracted services are prepared by external Quantity Surveyors using industry accepted guides.

In preparing its estimates for system planning capex, Ausgrid has made no allowance for risk or uncertainty.

For further information, please refer to the supporting document ID29045 Non-system property strategy Capex & Opex, provided as part of Ausgrid's regulatory proposal.

System Planning Capex (Area Plans, Replacement and Duty of Care Plans)

Ausgrid separates the cost elements of system planning capex into three categories:

- Contracted services;
- Labour;
- Materials.

Each cost element of system planning capex are derived using a number of the different methods outlined in 5.3, including combinations of methods.

For contracted services, Ausgrid has adopted a competitive tendering process to pre-select panels of preferred contractors for these works. Additionally, Ausgrid's cost estimates for contracted services are electronically linked and updated quarterly to Cordell's Building Industrial and Commercial Cost Guide. This guide is an industry accepted guide for the cost of buying and installing building materials that has been prepared from comprehensive analysis of the construction costs of actual building projects throughout NSW and Victoria.

For material costs, Ausgrid's estimates have been prepared using current manufacturers and suppliers period contract prices for major equipment, such as transformers, switchgear, cable etc. Ausgrid also uses its own supplies for minor electrical equipment and consumables (eg. lugs, screws, conduit etc) – these costs are electronically linked to estimates updated monthly in Ausgrid's SAP system.

For labour costs, Ausgrid's estimates have been prepared using the NECA Manual of Labour Units for the installation of equipment. These Labour Units are used for the electrical and communications industry which is the industry standard for estimating direct labour hours. Additionally, Ausgrid benchmark these rates against completed similar projects.

In preparing its estimates for system planning capex, Ausgrid has made no allowance for risk, uncertainty or contingency (5.3(f)).

For further information, please refer to supporting document ID00075 Methodology and cost estimates for pricing substations, feeders and 11kV switchboard replacement - Volumes 1 to 9, provided as part of our regulatory proposal.

ICT Capex

Each cost element is based on unit cost rates and effort estimates. Analysis of how the unit cost rates and effort estimates were derived is discussed below.

The unit rates are based on a number of inputs, as documented in Table 11.

Table 11 Unit cost elements and relevant forecast capex category(s)

Unit Cost element	Basis of the unit cost	Relevant forecast capex category(s)
Internal labour / Labour hire	FY2012/13 actual blended rates and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks
Hardware Server	Blended vendor contract cost renegotiated in FY2012	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
Hardware Storage	Blended vendor contract cost renegotiated in FY2012	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
Hardware – Telecommunications	Vendor contract cost renegotiated in FY2012 which were initially subject to competitive tenders	e) based upon actual historical costs for similar projects b) based upon competitive tender processes for similar projects
Software	Current contract cost (usually competitive tender) and consultation with vendors	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
Facilities management	Blended vendor contract cost renegotiated in FY2012 and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks
Data centre floor charge	Blended vendor contract cost renegotiated in FY2012 and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks
Desktop and service desk services	Vendor contract cost and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks

The project effort and resource estimates are largely based on historical costs for similar projects (that is, e) based upon actual historical costs for similar projects). On a business case level, the basis of the project estimates are explained in Table 12.

Table 12 Basis of business case effort estimates

Business case	Basis of the business case effort estimate	Relevant forecast capex category(s)
01. Regulatory Obligations & Licence Conditions	Historical estimates on similar regulatory projects	e) based upon actual historical costs for similar projects
02. Technology Licence Growth	Historical estimates on similar licence growth projects	e) based upon actual historical costs for similar projects
03. ICT Security	Historical estimates on similar ICT security projects	e) based upon actual historical costs for similar projects
04. End of Life Application Maintenance	Historical estimates on similar application maintenance projects and vendor contracts	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
05. Mandatory Compliance Enhancements	Historical estimates on similar mandatory changes to systems	e) based upon actual historical costs for similar projects
06. SAP Core Maintenance	Historical estimates on similar SAP maintenance projects	e) based upon actual historical costs for similar projects
07. Infrastructure Capacity & Maintenance	Historical estimates on similar infrastructure projects	e) based upon actual historical costs for similar projects
08. Workplace Technology	Historical estimates on similar workplace technology projects	e) based upon actual historical costs for similar projects
09. Telecommunications Capacity & Maintenance	Historical estimates on similar telecommunication projects	e) based upon actual historical costs for similar projects
10. Distribution Monitoring & Control Rollout	Historical estimates on the same project	e) based upon actual historical costs for similar projects
11. Fieldforce Automation Program	Stream 1A is based on competitive tender processes. Stream 1B and 1C are estimates based on historical cost estimates for	a) based upon competitive tender processes e) based upon actual historical costs for similar projects

Business case	Basis of the business case effort estimate	Relevant forecast capex category(s)
	large programs	
12. DNMS and SCADA Program	Historical estimates on similar DNMS and SCADA projects	e) based upon actual historical costs for similar projects
18. Network Secondary Systems Maintenance	Historical estimates on similar Network Secondary Systems maintenance projects	e) based upon actual historical costs for similar projects

There are no forecast capex estimates specifically due to category f) reflective of any amounts for risk, uncertainty or other unspecified contingency factors.

5.4 Provide all documents which were taken into account and relate to the deliverability of forecast capex and explain the proposed deliverability.

Consideration of our ability to deliver on capex is integrated into our business-as-usual capital planning processes. A description of our forecast capex and our approach to develop this forecast is included in the seven overview attachments that outline our capex plans. Our forecast capex for 2014-19 is lower than our actual capex for 2009-14 and so we do not envisage having to adopt any significant new delivery models to allow us to deliver our forecast capex. Ausgrid has also commented on delivery of capex projects in Chapter 5.1 of our regulatory proposal.

The capex plan overview documents are provided as the following attachments to Ausgrid's regulatory proposal:

- Area plans capex – Attachment 5.23
- ICT plan capex – Attachment 5.27
- Reliability plan capex Attachment 5.26
- Replacement and Duty of Care plans capex Attachment 5.24
- Non-system property plan capex Attachment 5.28
- Fleet plan capex – Attachment 5.29
- Distribution capacity plan capex Attachment 5.25

Capex categories

5.5 Describe each capex category and expenditures comprising these categories identified in the regulatory templates, including:

a) key drivers for expenditure;

Chapter 5.2 of our regulatory proposal sets out the key drivers of expenditure over the period.

Below we identify each of these drivers, and how they have impacted forecast capex categories identified in the AER's regulatory templates.

- Focus on affordability Industry reform has focused Ausgrid on achieving affordability for our customers. Accordingly our planning processes have been refined to consider the ability to avoid or defer investment where risks can be tolerated. Our forecasts have also incorporated prioritisation of the capex program which has identified opportunities to further defer capital programs to meet our goal of affordability. The focus on affordability has impacted all categories of capex including augmentation, replacement, connections and non-network capex. For example, we have prudently deferred replacement capex when we consider there are avenues to mitigate or tolerate the risk.
- Condition of assets on the network Our proposal recognises the need to replace assets to avoid a decline in safety and reliability. Our analysis shows that we still have a significant proportion of aged assets on our

network despite investment in the 2009-14 period. The continued deterioration in asset health has been a key driver of higher replacement expenditure in the 2014-19 period.

- Pockets of growth on network   While system peak demand is moderate, capacity investment is still required to meet pockets of growth on the network. Spot loads in localised areas of the network are a key driver of our augmentation programs and our proposed expenditure on customer connections.
- NSW licence conditions – A key consideration we have taken into account is the NSW Government change to licence conditions which will be effective 1 July 2014. In recognition of the increased flexibility these licence conditions will permit, Ausgrid has modelled its capacity driven investment requirements using less stringent decision criteria. However it should be noted that the capacity investment is largely being driven by spot loads from customer connections, and therefore there is less opportunity to defer investment as the load at risk is high. The change in licence conditions has impacted our total augmentation capex, although there were limited opportunities to defer capex as a result.

b) an explanation of how expenditure is distinguished between:

i. demand driven and non-demand driven augmentation capital expenditure;

Ausgrid's capital plans mostly relate to meeting localised demand on pockets of the network to ensure that we maintain the security of the network, and meet our average reliability performance targets. We would also consider that work undertaken to meet voltage concerns are also to some extent driven by changes in demand, and therefore do not conceive of this as separate from demand driven augmentation.

The aspect of augmentations that may be best described as non-demand driven is the program of works on remediating individual 11kV feeders that do not meet the prescribed performance in Schedule 3 of the Design, Reliability and Performance (DRP) licence conditions. This is part of our Reliability Plan.

ii. connections expenditure and augmentation capital expenditure;

Ausgrid considers that connections expenditure is a part of augmenting the network to meet demand within specified security criteria. Our manner of distinguishing between connection expenditure and reinforcement (which would be more closely related to the AER's definition of augmentation) is to develop a separate plan for each driver.

Connections expenditure is based on all the augmentations of the shared network (ie: exclusive of dedicated works which are funded by the customers) we undertake prior to connecting a customer to the network. Reinforcements relate to all augmentation expenditure on the shared network undertaken after a customer has connected, and is in response to aggregate localised demand by a combination of new customers connecting to the network and organic growth of existing customers.

iii. replacement capital expenditure driven by condition and asset replacements driven by other drivers (e.g. the need for demand or non-demand driven augmentation capital expenditure); and

There are two drivers of replacement of network assets. The first relates to when the asset's inherent condition has deteriorated due to age or other causes (for instance, operating conditions). The second relates to when the asset is failing to meet modern day standards of infrastructure. The latter is termed a Duty of Care driver.

Ausgrid's capital plans identify the driver of replacement. For example, we have separate Duty of Care plans, which identify distribution and smaller sub-transmission assets which no longer meet modern day standards. Further, our Area Plans will identify whether the driver of replacement is due to inherent deterioration in the condition of asset, or for a Duty of care reason.

iv. any other capex category or opex category where Ausgrid considers that there is reasonable scope for ambiguity in categorisation.

We have not identified any other ambiguity that may arise.

6. REPLACEMENT CAPITAL EXPENDITURE MODELLING

6.1 In relation to information provided in regulatory templates 2.2 and 5.2 and with respect to the AER's repex model, provide:

a) In relation to individual asset categories set out in the regulatory templates, provide in a separate document:

i. a description of the asset category, including:

General comments

There are two major components to Table 2.2.1: the Maintenance and Replacement Program (M&RP) and the Subtransmission Strategic Major Projects (ARA).

M&RP

Ausgrid has two primary asset management systems for assets used to 'deliver network services'. SAP is used for the technical information / characteristics of our network assets. GIS is used for the geospatial information in regard to those assets. Both asset management systems have been used to produce the asset age profiles against the defined asset categories and sub-categories on the regulatory templates '2.2 Repex' and '5.2 Asset Age Profile'.

The explanations given for the main drivers for replacement for the different asset categories is not an exhaustive explanation of those drivers comprehensive detail in regard to the main failure modes associated with the asset categories is available in the replacement asset condition and planning summary documents ('ACAPS') provided as part of the substantive regulatory submission. In addition to this, the asset replacement undertaken due to these main drivers is not necessarily always funded by Repex.

ARA

The ARA is differentiated from M&RP only in that the source data used to populate Table 2.2.1 originates from a Business Intelligence (BI) Report from Ausgrid's corporate SAP - Business Process Consolidation (BPC) database.

Figure 1 demonstrates how the BPC categories are aligned with the categories used in Table 2.2.1.

Figure 1 Alignment of BPC and RIN asset categories

BPC Categories	Rin Categories	
11kV Underground Cable, including UGOHs (XLPE)	p> 1 kV & < = 11 kV	UNDERGROUND CABLES
33 kV Concrete and Steel Pole Lines Mains Conductor & Access	p> 22 kV & < = 66 kV; CONCRETE	POLES
33 kV Underground Cables (XLPE Type)	p> 22 kV & < = 33 kV	UNDERGROUND CABLES
Zone CLC equipment (Electronic)	pZone CLC equipment (Electronic)	OTHER
Zone Communications	pCOMMUNICATIONS NETWORK ASSETS	SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS
Zone DC Systems	pMASTER STATION ASSETS	SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS
Zone General (including spares)	pZone General (including spares)	OTHER
Zone Substation Building	pBUILDINGS	OTHER
Zone Switchgear 11kV (Vacuum)	p< = 11 kV ; CIRCUIT BREAKER	SWITCHGEAR
Zone Switchgear 33kV (Gas)	p> 22 kV & < = 33 kV ; CIRCUIT BREAKER	SWITCHGEAR
Zone Transformers - 33/11kV (Oil)	pGROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA	TRANSFORMERS
Zone prot. & control equipment (Electronic)	pZone prot. & control equipment (Electronic)	OTHER
66 kV Concrete and Steel Pole Lines Mains Conductor & Access	p> 22 kV & < = 66 kV; CONCRETE	POLES
Zone Switchgear 132kV (Gas)	p> 66 kV & < = 132 kV ; CIRCUIT BREAKER	SWITCHGEAR
Zone Transformers - 132/11kV (Oil)	pGROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; < = 100 MVA	TRANSFORMERS
132 kV Underground Cable (XLPE Type)	p> 66 kV & < = 132 kV	UNDERGROUND CABLES
STS Switchgear 33kV (Gas)	p> 22 kV & < = 33 kV ; CIRCUIT BREAKER	SWITCHGEAR
STS Transformers - 132/33kV (Oil)	pGROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; > 100 MVA	TRANSFORMERS
Zone Switchgear 11kV (Oil)	p< = 11 kV ; CIRCUIT BREAKER	SWITCHGEAR
132kV Concrete and Steel Pole Lines Mains Conductor & Access	p> 132 kV; CONCRETE	POLES
Distribution Main OH System Easement	p< = 1 kV	OVERHEAD CONDUCTORS
Zone Switchgear 66kV (Gas)	p> 33 kV & < = 66 kV ; CIRCUIT BREAKER	SWITCHGEAR
Zone Transformers - 66/11kV (Oil)	pGROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; > 40 MVA	TRANSFORMERS
STS Protection & Control (Electronic)	pSTS Protection & Control (Electronic)	OTHER
STSs Switchgear 132kV (Gas)	p> 66 kV & < = 132 kV ; CIRCUIT BREAKER	SWITCHGEAR
132 kV Underground Cable (Oil Filled Type)	p> 66 kV & < = 132 kV	UNDERGROUND CABLES
STS Switchgear 66kV (Gas)	p> 33 kV & < = 66 kV ; CIRCUIT BREAKER	SWITCHGEAR
STS Reactors and Capacitors	pSTS Reactors and Capacitors	OTHER
Sub-Transmission Main OH Easement	pSub-Transmission Main OH Easement	OTHER
STS Building (incl sw. stns)	pSTS Building (incl sw. stns)	OTHER
STS Communications	pSTS Communications	OTHER
STS DC Systems	pSTS DC Systems	OTHER
STS General (including spares)	pSTS General (including spares)	OTHER
STS Switchgear 33kV (Oil)	p> 22 kV & < = 33 kV ; CIRCUIT BREAKER	SWITCHGEAR
Zone Reactors and Capacitors	pZone Reactors and Capacitors	OTHER
Zone Switchgear 33kV (Oil)	p> 22 kV & < = 33 kV ; CIRCUIT BREAKER	SWITCHGEAR
33 kV Underground Cables (Gas-Filled Type)	p> 22 kV & < = 33 kV	UNDERGROUND CABLES
33 kV Underground Cables (HSL Type)	p> 22 kV & < = 33 kV	UNDERGROUND CABLES
Zone CLC equipment (Mechanical)	pZone CLC equipment (Mechanical)	OTHER
Suburban	pSuburban	OTHER
33 kV Underground Cables (Oil-Filled Type)	p> 22 kV & < = 33 kV	UNDERGROUND CABLES
Zone Switchgear 132kV (Oil)	p> 66 kV & < = 132 kV ; CIRCUIT BREAKER	SWITCHGEAR
66 kV Underground Cable (XLPE Type)	p> 33 kV & < = 66 kV	UNDERGROUND CABLES
Zone Switchgear 66kV (Oil)	p> 33 kV & < = 66 kV ; CIRCUIT BREAKER	SWITCHGEAR
66 kV Underground Cable (Oil Filled Type)	p> 33 kV & < = 66 kV	UNDERGROUND CABLES
STS Switchgear 66kV (Oil)	p> 33 kV & < = 66 kV ; CIRCUIT BREAKER	SWITCHGEAR
11kV and 22kV Mains Bare Wire Conductor & Accessories	p> 1 kV & < = 11 kV	OVERHEAD CONDUCTORS
11kV and 22kV Mains CCT Wood Poles	p> 1 kV & < = 11 kV; WOOD	POLES
STS Transformers - 132/66kV (Oil)	pGROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; > 100 MVA	TRANSFORMERS
STSs Switchgear 132kV (Oil)	p> 66 kV & < = 132 kV ; CIRCUIT BREAKER	SWITCHGEAR
Pits	p> 1 kV & < = 11 kV	UNDERGROUND CABLES

The following detail outlines the individual asset categories which is relevant to both M&RP and ARA Programs.

A. the assets included and any boundary issues (i.e. with other asset categories);

Poles

This asset category includes all Ausgrid owned poles (including stay poles) used to 'deliver network services' in accordance with the RIN Appendix F Definitions but excludes dedicated public lighting poles which have been included under the "Public Lighting" category. Dedicated public lighting poles are those which do not have any mains attached to them other than public lighting circuits.

This asset category excludes ground stays (which are included in 'Pole top structures) and steel towers (which are included in 'Other – Towers').

Pole top structures

This asset category includes Ausgrid owned cross arms, insulators, terminations and ground stays mounted on poles used to 'deliver network services' in accordance with the RIN Appendix F Definitions. It excludes the overhead conductor component or any other assets (air break switches or links, reclosers, transformers etc) attached to the pole.

Overhead conductors

This asset category includes all Ausgrid owned overhead conductors, earthing conductors, spreaders and other conductor fittings in accordance with the RIN Appendix F Definitions. This excludes service wires (included under 'Service Lines'), public lighting conductors, pole top structures or conductors with fibre optic cables within them (OPGW / ADSS) used for protection or communications functions (included under 'SCADA, Network Control and Protection Systems').

Underground cables

This asset category includes all Ausgrid owned underground cables, cable pits / tunnels, joints, pillars / terminations in accordance with the RIN Appendix F Definitions. This asset category excludes underground service cables (included under 'Service Lines'), public lighting cables and fibre optic or copper pilot cables used for protection or communications functions (included under 'SCADA, Network Control and Protection Systems').

Service lines

This asset category includes all Ausgrid owned underground service cables and overhead service wires which directly supply an end customer in accordance with the RIN Appendix F Definitions. This asset category excludes privately owned mains and public lighting customers, as well as 'direct distributor' connections which are large supplies to a customer directly fed from the output of a distribution substation.

Transformers

This asset category includes all Ausgrid owned distribution and sub-transmission power transformers in accordance with the RIN Appendix F Definitions. This asset category does not include those used as instrument transformers (for example, current transformers or voltage transformers.

Switchgear

This asset category includes all Ausgrid owned high voltage and low voltage circuit breakers, ring main and fuse switch units, isolating / earthing switches, air break switches, enclosed load break switches, reclosers, sectionalisers, links (overhead and underground) and fuses in accordance with the RIN Appendix F Definitions.

Public lighting

This asset category includes all Ausgrid owned lamps, luminaires, brackets and dedicated public lighting poles / columns in accordance with the RIN Appendix F Definitions. Ausgrid owned assets are categorised as Rate 1 assets which have been constructed by Ausgrid and Rate 2 assets which are constructed by public lighting customers and 'gifted' to Ausgrid. The asset category excludes poles which also support assets used to 'deliver network services' and the dedicated overhead wires or underground cables used to supply public lighting. The asset category also excludes public lighting components not owned by Ausgrid (Rate 3 assets).

SCADA, Network Control and Protection Systems

This asset category includes all Ausgrid owned protection, voltage regulation and control relays, SCADA remote terminal units ('RTU's), fibre optic / copper pilot cables used for protection and / or communications functions, and

SCADA master station assets in accordance with the RIN Appendix F Definitions. The asset category excludes substation batteries and DC systems, customer load control equipment, the panels etc on which relays are mounted, local SCADA control boards / terminals in substations and secondary wiring for these assets.

Other – Distribution substations

This asset category has been added into the templates 2.2 and 5.2 by Ausgrid and includes all Ausgrid owned substation locations which transform voltage from either 33kv, 22kV or 11kV to a voltage level below 1kV as well as the assets within those locations in accordance with the RIN Appendix F Definitions. Asset category 'boundary issues' occur between this category and the 'Pole', 'Switchgear' and 'Transformer' asset categories in templates 2.2 and 5.2 because these asset categories could be considered as asset sub-categories within an overarching 'Distribution substations' category. This has created difficulties for reporting Repex expenditure against the separate asset categories, particularly in cases where a distribution substation is completely replaced, because existing financial systems and project cost allocation is not set up to provide this level of separate detail and therefore cost apportionment has been required.

The 'Distribution substations' asset category excludes distribution network assets used for voltage support on the distribution network - these assets have been included in the "Distribution voltage regulation" asset category also added into the templates 2.2 and 5.2 by Ausgrid.

Other – Distribution voltage regulation

This asset category has been added into the templates 2.2 and 5.2 by Ausgrid and includes all Ausgrid owned asset locations which provide voltage support (power factor correction by pole capacitors or voltage correction by voltage regulators) to the 11kV distribution network. A definition for this asset category is not included in RIN Appendix F Definitions. Asset category 'boundary issues' occur between this category and the 'Pole' and 'Switchgear' asset categories in templates 2.2 and 5.2 because these asset categories could be considered as asset sub-categories within an overarching 'Distribution voltage regulation' category. This has created difficulties for reporting Repex expenditure against the separate asset categories, particularly in cases where a distribution voltage regulation asset is completely replaced, because existing financial systems and project cost allocation is not set up to provide this level of separate detail and therefore cost apportionment has been required.

The 'Distribution voltage regulation' asset category excludes tap changers in transformers / capacitor banks in Zone or Sub-transmission substations. Zone and sub-transmission substation transformers are included in the 'Transformers' asset category.

Other – Towers

This asset category has been added into the templates 2.2 and 5.2 by Ausgrid and includes all Ausgrid owned steel towers used primarily for 132kV sub-transmission lines. A definition for this asset category is not included in RIN Appendix F Definitions.

Other – Zone and Subtransmission substations

This asset category has been added into the templates 2.2 and 5.2 by Ausgrid and includes all Ausgrid owned Zone and Sub-transmission substation locations in accordance with the RIN Appendix F Definitions. Asset category 'boundary issues' occur between this category and the 'Pole', 'Switchgear' and 'Transformer' asset categories in templates 2.2 and 5.2 because these asset categories could be considered as asset sub-categories within an overarching 'Zone and Subtransmission substations' category.

Other – Meters

This asset category has been added into the templates 2.2 and 5.2 by Ausgrid and includes all Ausgrid owned single phase and three phase meters used at customer installations. A specific definition for 'Meters' is not included in RIN Appendix F Definitions. This asset category excludes meters used within Ausgrid substations.

B. an explanation of how these matters have been accounted for in determining quantities in the age profile;

Poles

The asset age profile for poles includes all Ausgrid owned poles – age data has been sourced from SAP. Public lighting poles are able to be separated from 'Poles' in our SAP asset management system and have been separated into the 'Public lighting' asset category age profile information.

Pole top structures

This asset category is not included in the regulatory template tab '5.2 Asset Age Profile'. Ausgrid does not record asset information to a granular level of detail for this asset category in either SAP or GIS.

Overhead conductors

The asset age profile for overhead conductors only includes the information in regard to the Ausgrid owned conductors age data is sourced from the GIS. Ausgrid does not record asset information to a granular level of detail for spreaders or other conductor fittings. Service wires, public lighting conductors and fibre optic pilot cables are able to be separated from 'conductors' in our SAP asset management system and have been separated in the asset category age profile information as explained above.

Underground cables

The asset age profile for underground cables only includes the information in regard to the Ausgrid owned cables – age data has been sourced from the GIS. Pits / tunnels, joints or pillars / terminations are not included as it is assumed that the cable age profile is indicative of the age profile of these components as they were mostly installed at the same time as the cable. Service cables, public lighting cables and pilot cables are able to be separated from 'underground cables' in our SAP asset management system and have been separated in the asset category age profile information as explained above.

Service lines

The age profile for 'Service lines' was obtained by extracting asset information for Ausgrid owned services (those not identified as private installations), and age data is sourced from the GIS. Where multiple segments of service line supply the one customer, these are still only counted as one service. This GIS information is merged with customer information retrieved from the Metering Business System (MBS) via the National Metering Identifier (NMI) of the supply point connected to the service line. The customer type attributed to the NMI in MBS was then used to classify the service line allowing distinction of those that are for residential or commercial/industrial connections.

Commissioning dates attached to the service line in GIS have been used to determine the installation year, however in the absence of data for this the installation data of the corresponding meter in MBS has been used. Where the installation year has been provided as prior to 1911, the count of services has been redistributed proportionately to the years from 1911 to 2000. All service lines have been classified as simple type as the classification of complex type is related to the actions undertaken during the original connection and thus have no relevance to its classification in situ. However the data has been broken down into sub-categories to distinguish overhead and underground services.

Transformers

The asset age profile for transformers includes all Ausgrid owned poles – age data has been sourced from SAP. The age profile information for instrument transformers has been excluded.

Switchgear

The asset age profile for switchgear includes all Ausgrid owned switchgear – age data has been sourced from SAP.

Public lighting

The asset age profile for public lighting assets includes all Ausgrid owned (Rate 1 and Rate 2) lamps, luminaires, brackets and dedicated public lighting poles / columns age data has been sourced from SAP. Allocating the asset to a 'major road' or 'minor road' sub-category required matching the pole number on each road type from a GIS extract to the public lighting pole number from the SAP information because SAP does not capture the road type in the asset record. The asset age profiles exclude the dedicated overhead mains or underground assets used to supply public lighting. Asset information in SAP and GIS is held at a granular level which allows separation of these assets from similar assets used to 'deliver network services'.

SCADA, Network Control and Protection Systems

The asset age profiles for relays and RTUs includes all Ausgrid owned assets of these types age data has been sourced from SAP. For RTUs, data for assets with a commissioning date of prior to 1985 is considered inaccurate as they were most likely aligned to control system assets which had been replaced. Assets with commissioning dates prior to 1985 were evenly distributed across the years from 1985 to 1995 the period for which SCADA retrofits to existing substations were undertaken.

The asset age profiles for fibre optic pilot cables for the last three years has been obtained from the PNI database. Previous years were estimated based on a fibre optic rollout program which commenced in 2004/5. The asset age profiles for copper pilots have been determined from GIS.

The age profiles for master station assets have been obtained from the actual equipment acquisition dates retained in purchasing documentation.

Other – Distribution substations

The asset age profiles for 'Distribution substations' includes all Ausgrid owned locations for assets of this type age data has been sourced from SAP. The age profile is for substation locations, not for the components within the substation, and also excludes those components detailed above. For the pole, switchgear and transformer components within a distribution substation, SAP has information to the granular level required to separate the age profiles for these components into their asset category.

Other – Distribution voltage regulation

The asset age profiles for 'Distribution voltage regulation' includes all Ausgrid owned equipment for assets of this type – age data has been sourced from SAP. The age profile also excludes those components detailed above. For the pole and switchgear components within a distribution voltage regulation location, SAP has information to the granular level required to separate the age profiles for these components into their asset category.

Other – Towers

The asset age profile for this asset category includes all Ausgrid owned steel towers age data has been sourced from SAP.

Other – Zone and Subtransmission substations

The asset age profile for 'Zone and Subtransmission substations' includes all Ausgrid owned locations for assets of this type age data has been sourced from SAP. The age profile is for these substation locations, not for the components within the substation, and also excludes those components detailed above. For the pole, switchgear and transformer components within zone or sub-transmission substations, SAP has information to the granular level required to separate the age profiles for these components into their asset category.

Other – Meters

The asset age profile for 'Zone and Subtransmission substations' includes all Ausgrid owned single phase and three phase meters used at customer installations age data has been sourced from the Ausgrid Metering Business System (MBS).

C. an explanation of the main drivers for replacement (e.g. condition, etc.); and

Poles

The primary driver for pole replacement is condition. Condition issues may include pole base issues identified during the pole inspection and treatment process (inspection of the pole below and near ground line) or during the Overhead Line Inspection process (inspection of the pole from ground line up, including attachments).

Poles are also replaced due to nature-induced damage (for example, storms, trees falling on mains causing the pole to fracture, fires) or due to third party damage (for example, vehicle impact). In the case of third party damage causing the need to replace a pole, the cost of the replacement will be transferred to the third party if they are known, as opposed to requiring funding from capex.

Poles may also need to be replaced for compliance with statutory clearance requirements (that is, clearance between ground level and exposed mains) or pole-top loading requirements if the conductor arrangement is altered beyond the strength of the existing pole. Another compliance issue that possibly needs to be addressed by pole replacement is for mains that cross navigable waterways. In these cases, the mains may not be at sufficient height to be safely clear of water vessels (e.g. yachts) and the risk remediation is only possible through the replacement of existing poles with taller poles.

A final reason for pole replacement is due to existing poles being in a location that causes safety risks to motor vehicles. These are known as "blackspot" poles. Ausgrid is provided with information from the NSW government Roads and Maritime Services department in regard to road accidents where vehicles have struck poles and caused injury or a fatality. The pole locations within the Ausgrid supply area are assessed and risk mitigation strategies implemented to move the pole causing the safety risk to a more appropriate location.

Pole top structures

The primary driver for pole top structure replacement is condition. Condition issues may include deterioration of timber cross arms due to environmental exposure over their life (cracking / splitting or rot), termite activity, pole fires or mechanical stress due to conductor movement. Condition issues due to corrosion affect both the steel components of insulators and metal bracing / fixtures used at the pole top. Other insulator condition issues include damage to the "skirts" due to third party damage (bullets / rocks), bird attack, or mechanical stress due to conductor movement. It is unlikely that Ausgrid will recuperate replacement costs from third party damage to these components.

Pole top structures are also replaced due to nature-induced damage (for example, storms / lightning, trees falling on mains / cross arms, fires).

Overhead conductors

The primary driver for overhead conductor replacement is condition. Condition issues may include deterioration due to mechanical stress / fatigue due to conductor movement, corrosion / deterioration of conductor materials / fittings or damage to strands due to phases clashing together. Condition issues may also be caused by nature-induced damage (for example, storms / lightning, falling trees or branches, fires).

Overhead conductor may also need replacement because the existing design may not have sufficient current carrying capacity to accommodate the existing or forecast electricity demand that it supplies.

Underground cables

The primary driver for underground cable replacement is condition. Condition issues may include deterioration of the cable / joints due to mechanical stress ground movement, corrosion / deterioration of conductor materials due to water ingress/ fittings, age related degradation of insulating materials or damage caused by third parties. There are two types of low voltage cable that are being replaced proactively due to known condition issues which can lead to public safety risks, they being 'CONSAC cable' and 'HDPE cable'.

'Obsolescence' is another factor which may drive cable replacement, particularly for self contained fluid filled cables ('SCFF') and gas pressure cables used at voltages of 33kV and above. These types of cables are resource intensive technologies which are no longer being supported by manufacturers / cable suppliers and for which Ausgrid's specialised jointing resources are depleting. These cable technologies were predominantly installed in the 1960s and 1970s and have been superseded by cross-linked polyethylene ('XLPE') cable technology.

In addition to this, SCFF cables use mineral oils for insulation and leakages present environmental pollution risks which has led to the implementation of an environmental management plan for these assets in association with the NSW Environmental Protection Authority. Gas pressure cables are experiencing high levels of gas leakage leading to increasing failures. Ausgrid has experienced a number of high profile outage events due to co-incident failure of parallel feeders with gas pressure cables and has determined that this level of risk is no longer acceptable for these cables.

Underground cables may also need replacement because the existing design may not have sufficient current carrying capacity to accommodate the existing or forecast electricity demand that the cable supplies.

Service lines

The primary driver for replacement of overhead service lines is condition. Condition issues may be identified during the Overhead Line Inspection process or customers reporting arcing or fallen service lines.

The condition issues which lead to replacement of overhead service lines generally relate to deterioration of the insulation around the conductors. This deterioration can be a result of age / fatigue or due to ultraviolet (UV) radiation damaging the insulation. When this occurs, arcing can occur between the active and neutral conductors which further damages the insulation or results in a breakdown failure of the conductor.

Overhead service lines are also replaced due to nature-induced damage (for example, storms, trees falling on the service line, fires) or due to third party damage (for example, vehicle impact). In the case of third party damage causing the need to replace a pole, the cost of the replacement will be transferred to the third party if they are known, as opposed to requiring funding from capex. Overhead service lines may also need to be replaced for compliance with statutory clearance requirements (that is, clearance between ground level and overhead mains).

The primary driver for replacement of underground service lines is condition. These condition issues will usually only become apparent following an interruption to supply caused by a service cable failure. These failures are usually caused by age degradation of the insulation (paper insulation), moisture ingress into the cable or third party damage ('dig-ins') on the customers property. The main types of underground service cables that are being replaced based on their condition is CONSAC service cables due to the known condition issues with that type of cable.

A final driver for service line replacement is alterations in customer installations. When a customer undertakes electrical work within their installation they may be required to replace the service line to their installation as part of that work. Any service line replacement undertaken due to this driver is funded by the customer undertaking the work.

Transformers

The primary driver for replacement of distribution transformers is condition. Condition issues which lead to replacement are usually associated with failures within the winding of the transformer or damage to the bushings. Some failures (particularly for pole mounted transformers) may be caused by nature-indcued events (for example, lightning strike on overhead mains, trees falling onto components, animals bridging across live components). Other condition issues (for example, corrosion, oil leakage) may be addressed by corrective work before the transformer fails.

The primary driver for replacement of transformers in zone or sub-transmission substations is age related deterioration of the transformer winding. Age related deterioration over the life of the transformer occurs due to thermal cycling, overloading, breakdown of organic materials within the winding, through-faults and other electrical stresses. Components of the winding which deteriorate with age include the paper insulation barriers, the insulating oil and insulating tapes used on the winding. Oil impregnated paper bushings also have a finite life. Tap changers wear out due to the number of operations they perform and in some cases their design.

With age, components within a transformer winding may become loose due to vibration causing the transformer to be above allowance environmental noise limits. In these cases complaints may be made by the public to environmental or local council authorities and this may lead to replacement of the transformer if it is uneconomical to repair it.

An additional driver for replacement of any transformer is its rating. When a transformer no longer has sufficient rating to supply the required loading, a transformer with a higher rating will be installed to supply that required loading.

Switchgear

The primary driver for replacement of switchgear is condition. Condition issues which lead to replacement are usually associated with breakdown of the components used to insulate the switches due to age (e.g. paper bushings, compound filled switchgear, moisture ingress), operation of the switch beyond its design (for example, switching or carrying currents beyond its rating), deterioration of components due to exposure to the elements (for example, corrosion, timber and insulator degradation) or nature induced events (for example, lightning strike, trees falling onto components, animals bridging across live components, water entry into underground assets).

Obsolescence may also be considered a driver for some switchgear replacement. Examples of this may include circuit breakers for which spare parts are no longer available or it is uneconomical to continue repairing them (for example, older 11kV air break switches and links, older ring main units and circuit breakers). Some circuit breaker technologies are aged to the point they are at or beyond their design life, and are no longer supported by manufacturers / suppliers, or the technologies cause a loss of supply risk that is no longer acceptable – this is particularly the case for some compound filled 11kV switchboards and some types of 33kV bulk oil circuit breakers.

Public lighting

The primary driver for public lighting pole / column replacement is condition. Condition issues primarily include pole base issues identified during the pole inspection and treatment process (inspection of the pole below and near ground line) or to a lesser extent those identified during the Overhead Line Inspection process (inspection of the pole from ground line up, including attachments).

Poles are also replaced due to nature-induced damage (for example, storms, trees falling on mains causing the pole to fracture,) or due to third party damage (for example, vehicle impact). In the case of third party damage causing the need to replace a pole, the cost of the replacement will be transferred to the third party if they are known as opposed to requiring funding from capex expenditure.

Lamps are replaced under a bulk lamp replacement ('BLR') strategy. As the lamp is the only component of the asset that is replaced, BLR is funded from operations expenditure.

Luminaires may be replaced due to condition issues (for example, corrosion, nature-induced events or due to extensive failure of internal components). Luminaires may also be replaced due to lamp technology changes.

Examples of technology change is the change from incandescent lamps to compact fluorescent lamps (CFL) or as is occurring now the change from CFL to LED lamps. When lamp technology changes the new lamps will not necessarily fit into the existing luminaires. This may be due to the configuration of the electrical connection for the new lamp not matching that in the existing luminaire, or the new lamp may require different control gear within the luminaire. Luminaire replacement may be funded as minor repex for spot replacement but also may be funded by public lighting customers if they choose to undertake a public lighting trial or replacement program.

Public lighting customers (for example local councils) may also request replacement of existing assets due to modernisation in for example commercial precincts or parks. In these cases, the work may be undertaken by Ausgrid or as contestable projects but will be funded by the customers. They may also choose whether the new assets become Rate 2 or Rate 3 assets following installation. Also in these cases, the public lighting customer will also reimburse Ausgrid for the depreciated value of the existing asset if it is not at 'end of life'.

SCADA, Network Control and Protection Systems

The primary driver for replacement of relays is condition. Condition issues for relays generally relate to age related wear of electromechanical components or poor performance trends for certain relay types identified during planned maintenance. Modern numerical / digital relays are generally 'self-checking' but are more likely to have firmware or software issues which are overcome through repairs as opposed to replacement. These condition issues may result in individual relay replacements or programmed relay replacement for specific relay types if a poor performance trend is evident.

The primary driver for replacement of pilot cables is condition issues associated with copper pilots. Copper pilot cables may use paper insulation in their structure which deteriorates due to moisture ingress into cables buried directly in the ground. Ground movement or third party damage (for example, dig-ins) may also affect the cable condition. While some of these condition issues can be overcome with repairs, the deterioration that occurs could be endemic along the majority of a pilot cable length requiring full replacement to overcome the condition issue. When a copper pilot requires replacement it will generally be replaced with a fibre optic pilot to align with current and future protection and control system digital technology.

The primary driver for RTUs and master station assets is obsolescence. Although condition issues in regard to RTUs may be addressed by individual component replacement within the RTU or control boards, local RTUs / control systems and master station assets operate as an end to end 'system' which requires technology alignment at both ends of the system. These systems generally have a shorter design life than the network assets they control because of the rapid change in technology for SCADA systems and the relatively short period for which manufacturers provide support for these systems.

Other – Distribution substations

The primary driver for distribution substation replacement is condition. For pole mounted distribution substations, the condition of the pole will be the main driver for replacement at or near the current location. For kiosk substations, the age related condition issues for the switchgear, transformers, the housing (for example, kiosk housing or substation building) or other components may lead to the substation being replaced if individual components cannot be replaced or if the current design for replacement components are not able to be installed within the existing substation due to the existing substation design.

Obsolescence can be another driver for substation replacement. The obsolescence may relate to individual components with the substation because they cannot be repaired due to age and lack of spares / manufacturer support or due to the design of an existing substation that may have been constructed many years ago to safety or building compliance requirements which are no longer relevant or are unsafe.

Customer driven replacement is also required. This may be due to redevelopment of an existing substation site or building in which a substation is located. This may also be caused by additional demand requirements that an existing substation does not have the rating capacity to supply. Customer driven replacement is generally funded by the customer.

Other – Distribution voltage regulation

The primary driver for distribution voltage regulators is age related condition issues. For ground level voltage regulators, the components that are included at each location (regulator, protection and voltage regulation relays, circuit breaker, air break switch and 11kV links, current transformers and security fences) are experiencing age related degradation due to long term exposure to the elements, poor performance trends and wear due the high number of operations they have carried out.

For pole mounted distribution voltage regulators or capacitors, the condition of the pole will be the main driver for replacement at or near the current location. If the pole needs to be replaced, a new asset will be built adjacent to the existing location if voltage support is still required at that point on the 11kV feeder. In most cases, the components from the old installation can be used as rotable replacement items when maintenance is required on other regulators or following a failure.

Other – Towers

The primary driver for steel tower replacement is condition. Condition issues may include tower base corrosion issues identified during the inspection process (inspection of the pole below and near ground line) or corrosion / mechanical stress to cross-members / bracing identified during the Overhead Line Inspection process (inspection of the tower from ground line up, including attachments). While these condition issues are mostly addressed by corrective maintenance, instances may occur where total replacement of the tower is required.

Steel towers may also require replacement due to nature-induced damage (for example, storms, fires) or due to design issues with the existing tower. An engineering survey of all Ausgrid owned steel towers has identified some types / locations of towers where the structural design strength of the tower may not be sufficient if all overhead conductors attached to one side of the tower fail and fall to the ground. Overhead conductors can provide structural stability for certain tower designs and if all conductors on one side of any of the towers of these designs fail, the mechanical stresses applied to these towers due to unbalanced loading can cause the tower to fail and collapse.

Other – Zone and Subtransmission substations

Zone or sub-transmission substation may have a number of drivers for their replacement. Condition or obsolescence issues may be related to some of the components within the substation (for example, building issues, switchgear condition, transformer condition, protection systems etc) or supply to the substation (for example, SCFF cable issues). The ability of the substation or feeders to supply the current or forecast capacity is another issue which may require investment to resolve the issue. Environmental and OH&S compliance issues may be a further driver for investment environmental issues may be due to noisy transformers, leaking SCFF cables or degraded oil containment components, OH&S compliance requirements may be due to the presence of asbestos materials within the substation. These and other drivers for investment are taken into account when 'Area Plan' analysis is undertaken to determine the most appropriate investment for individual supply areas. This analysis may determine that the optimum investment for the area is to completely replace the existing substation, augment the substation or only to replace the components with the issues within that substation.

Other – Meters

There are no metering costs or quantities recorded in Table 2.2.1.

D. an explanation of whether the replacement unit cost provides for a complete replacement of the asset, or some other activity, including an extension of the asset's life (e.g. pole staking) and whether the costs of this extension or other activity are capitalised or not.

Ausgrid notes that the AER removed unit rate information from Table 2.2.1 in the amended version of the Reset RIN issued on 21 March 2014.

Poles

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Pole top structures

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Overhead conductors

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Underground cables

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Service lines

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Transformers

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Switchgear

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Public lighting

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

SCADA, Network Control and Protection Systems

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Other – Distribution substations

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Other – Distribution voltage regulation

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Other – Towers

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Other – Zone and Subtransmission substations

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

Other – Meters

Replacement unit costs were not asked for in regulatory template tabs '2.2 Repex' or '5.2 Asset Age Profile'.

ii.an estimate of the proportion of assets replaced for each year of the current regulatory control period, due to:

A. aging of existing assets (e.g. condition, obsolesce, etc) that should be largely captured by this form of replacement modelling;

Table 13 shows the proportion of the total population of assets replaced due to aging / condition / obsolescence during the current regulatory period. The final year of the current regulatory period has not been shown as it is still in progress but the proportion of assets replaced is expected to be within the ranges of the previous years.

Table 13 Proportion of assets replaced

Asset Category		2009/10	2010/11	2011/12	2012/13
Poles	% replaced % staked	0.8% 1.0%	0.8% 0.6%	0.8% 0.7%	0.7% 0.5%
Overhead conductors	% replaced	0.1%	0.1%	0.2%	0.2%
Underground cables	% replaced	0.1%	0.1%	0.2%	0.1%
Service Lines	% replaced	3.1%	2.5%	2.7%	2.0%
Transformers	% replaced	0.9%	0.7%	0.9%	0.7%
Switchgear	% replaced	3.6%	4.3%	3.3%	3.8%
Public Lighting	Lamps - % replaced Poles - % replaced	50.8% 1.5%	49.9% 1.5%	48.3% 2.4%	52.4% 2.1%
SCADA / Field Devices	% replaced	0.0%	0.0%	0.1%	0.1%
Distribution Substations – other equipment	% replaced	4.1%	3.7%	5.6%	6.5%
Distribution Voltage Regulators	% replaced	2.2%	1.0%	2.5%	5.3%
Zone and Sub-transmission substations – other equipment	% replaced	8.7%	10.7%	23.0%	11.7%

The high proportion of Service Lines replaced is based on overhead service lines. Ausgrid has a program for planned replacement of overhead service lines due to known condition issues with PVC insulation and service clamps which lead to electrical safety and fire risks to the general public.

The high proportion of switchgear being replaced is mainly driven by planned replacement of 11kV circuit breakers and operational switches (air break switches) due to known condition issues with these types of switchgear.

The proportion of public lighting lamps replaced can be explained by technology issues being experienced with the introduction of compact fluorescent (CFL) and now light emitting diode (LED) lighting technologies. Both types of lamps have experienced high failure rates leading to high levels of spot replacement.

The high proportion of 'other equipment' being replaced in distribution, zone and sub-transmission substations can be explained by inaccuracy in the total population of the 'other equipment'. 'Other equipment' being replaced includes batteries, earthing systems, current / voltage transformers, pit lids, fences, oil containment systems and other components which are not necessarily recorded in SAP to such a granular level that the exact total population can be determined.

B. replacements due to other factors (and a description of those factors);

Replacement may be required due to duty of care environmental, safety and infrastructure risk requirements and these have mostly been included in the replacement proportioning above.

The ability of the existing equipment to supply the existing or forecast electrical capacity of a part of the electrical network is another issue which may require replacement of an asset to resolve the issue.

'Area Plan' analysis is undertaken in regard to the sub-transmission supply areas to determine the most appropriate investment for each individual supply area. This analysis integrates all investment drivers within that area to determine the optimum investment required for the area and this may include completely replacing the existing substations / feeders within the area, augmenting the existing substations / feeders within that area, or only to replace the components with the condition issues within that area (for example, 11kV switchgear within the substation or replace SCFF cable only).

In 'Area Plan' projects a primary driver and its associated costs are identified. Subsequent drivers are allocated the remaining costs. The ratio of cost between drivers is used to apportion asset quantities.

C. additional assets due to the augmentation, extension, development of the network; and

As indicated above, subsequent drivers are allocated the remaining costs of a project, once the costs of the primary driver have been removed.

D. additional assets due to other factors (and a description of those factors).

Additional assets may also be installed due to reliability issues or due to design issues when assets are replaced. Reliability issues may result in re-conductoring of bare overhead mains with covered conductor to prevent interruptions due to vegetation contact and may also lead to the installation of pole top reclosers to segment the high voltage feeder into smaller separable sections to reduce the extent of interruption on the high voltage feeder when a failure occurs.

When assets are replaced, the existing assets were mostly built to old design requirements which have mostly been superseded with more onerous requirements due to safety requirements. An example of design issues is the possible requirement to install additional poles when overhead mains or condemned poles are replaced. The additional poles may be required due to changes in design standards since the existing poles were originally installed and the new standards are more onerous in regard to the location / separation / pole top loading that is now required.

GIS does not capture the investment driver for assets within those systems and as such the proportion replaced due to these investment drivers cannot be accurately estimated.

b) Justification for the replacement life statistics provided (the mean and standard deviation), including:

i. the methodology, data sources and assumptions used to derive the statistics;

Ausgrid has addressed this requirement in the Basis of Preparation accompanying the regulatory templates.

ii. the relationship to historical replacement lives for that asset category; and

Mean and standard deviations used in the RIN were based on individual assets removed from service. This gave a view of asset economic life rather than replacement life as the condition driven removals could not be separated.

iii. Ausgrid's views on the most appropriate probability distribution to simulate the replacement needs of that asset category, including matters such as:

A. **the appropriateness of the normal distribution or another distribution (e.g. the Weibull distribution);**

B. **the typical age when the "wear out" phase becomes evident;**

C. **the "skewness" of the distribution; and**

D. **the process applied to verify that the parameters are a reasonable estimate of the life for the asset category.**

Ausgrid currently does not apply probability distribution to each of its asset categories. The exception to this is zone and STS transformers. With the availability of greater data and further analysis, Ausgrid may able to simulate a probability distribution for each category to support replacement needs.

Given the electro-mechanical nature of the large majority of Ausgrid assets, it would be expected that the majority of assets would display a wear-out characteristic. This however is changing with the introduction of more complex electronic technology. The appropriate shape and hence skewness of the distribution used will vary depending on the asset group being analysed. This will be affected by environmental influences, the assets operating environment, the current maintenance regimes employed and the design of the individual and varied assets, within each asset category. This level of complexity makes prediction of imminent failure difficult.

For example, CONSAC and HDPE cables are failing prematurely due to the aluminium materials used in the cable and the influence of moisture on the cables. This technology would therefore skew the probability distribution when grouped with other underground cables at the same voltage level. This example highlights that age alone cannot be used to give an indication of failure without fully understanding the nature of failure for each asset category. It is for this reason that Ausgrid employs a rigorous maintenance regime to, where possible, effective and efficient, monitor the condition of assets and rectify imminent issues through repair or reactive replacements.

It should be noted that the consequence of failure must be taken into account when assessing and selecting optimal replacement timeframes. Assets with greater consequence may be replaced earlier in their life against assets with a lower consequence to ensure optimal risk mitigation. It is only through applying this that a risk based approach can be adopted in determining replacement needs.

c) The derivation of replacement unit costs and asset lives, including any internal documentation or analysis or independent benchmarking, that justifies or supports its cost data. This must cover:

i. the methodology, data sources and assumptions used to derive the cost data;

ii. the possibility of double-counting costs in the estimate, and the process applied to ensure this is appropriately accounted for;

iii. the variability in the unit costs between individual asset replacements, and the main drivers of the variability;

iv. the relationship of the unit cost, and its derivation, to historical replacement costs for that asset category (this should clearly differentiate and quantify any assumed cost difference due to labour/material price changes and other factors);

v. the process applied to verify that the parameter is a reasonable estimate of the unit cost for the asset category; and

vi. identify and provide information or documentation to justify and support any responses to c) above.

Ausgrid notes that the AER removed unit rate information from Table 2.2.1 in the amended version of the Reset RIN issued on 21 March 2014.

Below is an integrated response to question 6.1(c).

Ausgrid's options assessment draws on accurate data on the costs of different solutions. This in turn provides us with a level of confidence on the forecast costs of completing our planned and reactive works.

For the 2014-19 proposal, Ausgrid has used a number of sources to identify the costs of planned and reactive replacement:

- Estimating systems: We use an estimating system called ATAD to estimate the costs of completing projects at Ausgrid. The system uses labour rates, allocations, material costs and contracted services rates.
- Site specific costs: There is the ability to vary for individual site or regional differences, such as travel time or known site conditions.

Historical project information: If available, cost information regarding previous projects of a similar nature is useful when costing options. This is drawn from Ausgrid's integrated asset management system (SAP). It may prove useful as there may be costs that are not apparent when initially estimating that should be taken into consideration. It should be noted that, depending on the project, this information may not always be available. However, as a result of the works completed in the 2010 - 2014 period, more information is readily available.

More information on the exact cost method we have used to determine different elements is contained in Supporting Document ID07366 Replacement & Duty of Care Plan (distribution projects) unit cost methodology as part of Ausgrid's regulatory proposal.

d) For the previous, current and forthcoming regulatory control periods, explain the drivers or factors that have affected changing network replacement expenditure requirements. Identify and quantify the relative effect of individual matters within the following categories:

i. rules, codes, license conditions, statutory requirements;

There have been no significant changes to legislation affecting Ausgrid's maintenance during the 2009 - 2014 regulatory period. Ausgrid has however, through continuous improvement of its maintenance program, sought to ensure compliance with current legal obligations.

ii. internal planning and asset management approaches;

In 2012 Ausgrid rolled out LIDAR patrols in bushfire areas. This was a new program at the time aimed at improving inspection effectiveness.

iii. measurable asset factors that affect the need for expenditure in this category (e.g. age profiles, risk profiles, condition trend, etc.). Identify and quantify individual factors;

The maintenance requirements analysis (MRA) studies the failure data reported against an asset and thus considers the failure rate and modes in establishing the most effective maintenance standard and required periodicity. Therefore changes to a maintenance standard or periodicity applied are indicative changes in the asset's failure rate or mode of failure. Over the regulatory period the most significant changes occurred to the following asset maintenance standards periodicity:

- overhead mains inspection tasks was extended from a 4 to 5 year interval
- pole base and ground line examination was extended from a 4 to 5 year interval
- kiosk type substations was extended from a 8 to 10 year interval
- single pole substation was extended from a 8 to 10 year interval.

There were changes to over 100 other maintenance standards, however, these were either only applicable to a small number of tasks or to the latitude (allowable range) of the maintenance periodicity.

iv. the external factors that can be forecast and the outcome measured (e.g. demand growth, customer numbers) that affect the need for expenditure in this category. Identify and quantify individual factors, covering the forecasts and the outcome (external factors to be discussed here do not relate to changing obligations which are covered in paragraph 4);

This is not applicable.

v. technology/solutions to address needs, covering:

A. network; and

B. non-network.

This is not applicable.

vi. any other significant matters.

This is not applicable.

The information provided above should at least distinguish between the asset categories defined above.

vii. Identify and provide information or documentation to justify and support any responses to 0 above.

Ausgrid has provided documentation in support of the responses to (d) above at Attachment G Changing Maintenance Standards for Replacement Capital Expenditure.

7. AUGMENTATION CAPITAL EXPENDITURE MODELLING

7.1 Any instructions in this Notice relating to the augex model must be read in conjunction with the augex model guidance document available on the AER's website.

The RIN Response has been prepared consistent with the guidance document.

7.2 In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide:

a) Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Ausgrid must explain how it:

i. Prepared the maximum demand data (weather corrected at 50 per cent probability of exceedance; see Schedule 2 for further guidance) provided in the asset status tables (tables 2.4.1 to 2.4.4), including where relevant:

A. how this value relates to the maximum demand that would be used for normal planning purposes;

Table 2.4.1 – Sub-transmission Lines
Maximum demand figures presented in this table are not used in normal planning purposes. In planning, sub-transmission feeder adequacy is assessed using load-flow analysis of network constraints under credible contingencies (e.g. N-1), based on network models with current and estimated future network topology combined with Ausgrid's established 50% POE forecast substation demand. This is outlined in Supporting Document ID88032 (INV-STD-10019) - Planning Standard - Area Planning.

The information provided in this table is a historical snapshot of peak system normal loading generally based on actual data from SCADA metering and prepared especially for the RIN. It is subsequently corrected for weather power-factor, abnormal switching and diversity, using estimated correction factors.

Table 2.4.2 – High Voltage Feeders

This historical data provided are not directly used in Ausgrid's normal planning processes. Planning of augmentation of HV feeders are done by load-flow models are constructed using Ausgrid's weather-corrected and trend-adjusted substation forecasts (based on raw historical data) to estimate maximum future demand on feeders under credible contingencies (N and N-1 loading).

Table 2.4.3 – Sub-transmission Substations and Zone Substations

The values provided reflect the "Base Forecast" prepared as input to the normal planning process as described in Supporting Document ID65078 (INV-STD-10022) Planning Standard Demand Forecast & related documents. This forecast forms the basis of assessing substation adequacy in normal planning processes.

Table 2.4.4 – Distribution Substations

The maximum demand data for distribution substations is based on the load survey program and is used for normal planning purposes. A large proportion of Ausgrid's population of Distribution Substations have load readings taken on a regular basis as part of this program. When planning activities are undertaken involving distribution substations that do not have relevant load survey data the substation is surveyed to determine the maximum demand as part of the design process and this data is entered into Ausgrid's SAP asset management systems.

These readings were obtained from SAP via a Business Objects report for the financial years requested by the RIN and taken as representative of the full population of Distribution Substations with scaling based on total MVA capacity across the defined network segments.

B. whether it is based upon a measured value, and if so, where the measurement point is and how abnormal operating conditions are allowed for;

Table 2.4.1

This data was prepared especially for the reset RIN only, and is based on actual SCADA data from local area peak or system peak, with estimated correction factors to comply with the requirements of the RIN. In many cases Ausgrid does not record MW values, and therefore estimates of power factor and voltage are required to convert AMP recordings to MW and MVA. The general process is as follows:

- The raw actuals are corrected for weather, power factor and abnormal switching when identified.
- Power factor is estimated by load-flow, as well as abnormal switching corrections.
- Weather correction factors are estimated from destination substations and used to adjust raw values.

Table 2.4.2 – High Voltage Feeders

Data used to populate this table is sourced from Ausgrid's SCADA system from the date and time of non-coincidental feeder peaks. It is raw data (AMPs) corrected to 50% POE using a factor calculated and assigned to the originating substation of the feeder. The load in AMPs is converted to MVA. The power factor of a feeder is assigned based on the settings at the originating substation and used to convert MVA to MW.

In the Hunter, annual feeder peaks are manually collected annually and used a basis for zone reviews; abnormal conditions are accounted for in the manual selection of feeder peaks. In Sydney and the Central Coast, feeder peaks are manually collected each time a zone substation's HV feeders are reviewed (generally follows a 2.5 year cycle). Consequently, a set of manually selected feeder peaks at a given point in time for Sydney and Central Feeders is unavailable. However, it is believed that the impact of abnormal conditions will be negligible across a whole network segment in the Augex Model.

Table 2.4.3 – Sub-transmission Substations and Zone Substations

The values provided reflect the "Base Forecast" prepared as input to the normal planning process. These are based on actual measurements and the process for correction is as described in investment standard Supporting Document ID65078 (INV-STD-10022) Planning Standard - Demand Forecast & related documents.

Table 2.4.4 – Distribution Substations

The values provided represent the measured values taken from Ausgrid's load survey program taken as representative of the total population of distribution substations. The measurements taken are generally of the B-phase maximum current occurring between readings of the maximum demand indicator (MDI).

Where high readings are obtained during the load survey program the network connectivity is assessed to ensure that the reading is valid and indicates the maximum demand under normal operating conditions. Where an instance of LV paralleling is found to have impacted the reading it is removed from the system.

C. whether it is based on estimated (rather than actual measured) demand, and if so, the basis of this estimation process and how it is validated; and

This is not applicable to Ausgrid.

D. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.

At a system level, raw summer demand was 12.5% higher in 2012/13 than calculated 50% POE value. The 10% POE value is 7% higher than the 50% POE value. Raw winter demand was 4% lower than the 50% POE value, and the 10% POE value was 1.4% higher than the 50% POE value.

ii. Determined the rating data provided in the asset status tables (tables 2.4.1 to 2.4.4), including where relevant:

A. the basis of the calculation of the ratings in that segment, including asset data measured and assumptions made; and

Table 2.4.1 – Sub-transmission Lines

The ratings provided are long-term cyclic ratings calculated in accordance with Ausgrid's established rating methodology. This methodology is outlined in document Supporting Document ID26254 (INV-STD-10026) Planning Standard - Ratings and impedances & related documents of the regulatory submission.

Table 2.4.2 – High Voltage Feeders

Ratings are calculated in the same way as sub-transmission lines and are recorded in Ausgrid's "Ratings and Impedance Calculator" (RIC) and "Line Impedance Data" (LID).

Table 2.4.3 – Sub-transmission Substations and Zone Substations

The ratings provided are long-term cyclic ratings calculated in accordance with Ausgrid's established rating methodology. This methodology is outlined in Supporting Document ID26254 (INV-STD-10026) Planning Standard – Ratings and impedances & related documents of the regulatory submission.

For "nameplate" and "maximum cooling method" ratings – no other substation limitations have been considered (e.g bay limitations, fault level limitations etc). These ratings are therefore not used in normal planning purposes.

Table 2.4.4 – Distribution Substations

The ratings in the Distribution Substation network segments are based on cyclic transformer ratings as outlined in Network Engineering Guideline NEG PD 01-4 Low Voltage Planning Manual Thermal Rating of Distribution Substations.

B. the relationship of these ratings with Ausgrid's approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation time, these should be defined and explained.

Table 2.4.1 – Sub-transmission Lines

The ratings are consistent with those used to determine augmentation timing.

Table 2.4.2 – High Voltage Feeders

The Operational Rating is only applicable to the CBD HV feeders which form the triplex network. As the CBD HV triplex network is designed with an N-1 security standard, the Operational Rating is estimated as two thirds that of the assigned Thermal Rating of each HV feeder.

The actual Operational Rating for urban and rural HV feeders may differ to the values recorded in the RIN template due to varying Thermal Ratings on each individual HV feeder forming part of the triplex circuit (group of three HV feeders) or due to protection limitations/restrictions, for example where the protection relay pick-up is set below two thirds of the thermal rating. In this case the actual Operational Rating would be set at below the protection relay pick-up.

Table 2.4.3 – Sub-transmission Substations and Zone Substations

Cyclic and Emergency ratings provided are consistent with those used to determine augmentation timing.

However "nameplate" and "maximum cooling method" ratings are not consistent with Ausgrid's approach to operating and planning the network. No other substation limitations have been considered (e.g. bay limitations, fault level limitations etc) when providing these ratings. These ratings are therefore not suitable for use in augmentation planning.

Table 2.4.4 – Distribution Substations

The cyclic transformer rating used for the RIN population is also used for all normal planning purposes.

iii. Determined the growth rate data provided in the asset status tables (tables 2.4.1 to 2.4.4). This should clearly indicate how these rates have been derived from maximum demand forecasts or other load forecasts available to Ausgrid.

Table 2.4.1 – Subtransmission Feeders

The growth rate is determined from annual base substation or feeder forecasts which include committed spots, transfers and projects. It is a derived value from the difference between 2018/19 forecast maximum demand and 2012/13 historical maximum demand according to the relationship:

Average Annual Maximum Demand Growth = ((Maximum Demand (2018/19) / Maximum Demand (2012/13))^(1/6)-1 * 100%

Note that Ausgrid prepares detailed forecasts for each substation which include both short term spatial and long term econometric factors, and does not use a single linear p.a. growth rate for planning purposes. This growth rate is therefore derived to achieve the expected maximum demand at each substation in accordance with Ausgrid's base spatial forecast for the 2018/19 year.

Table 2.4.2 – High Voltage Feeders

The growth rates of HV feeders are assumed to be the same as the growth rate of their originating zone substation (see below).

Table 2.4.3 – Subtransmission Substations and Zone Substations

The growth rate is determined from annual base substation or feeder forecasts which include committed spots, transfers and substations. It is a derived value from the difference between 2018/19 forecast maximum demand and 2012/13 historical maximum demand according to the relationship:

> Average Annual Maximum Demand Growth = ((Maximum Demand (2018/19) / Maximum Demand (2012/13))^(1/6)-1 * 100%

Note that Ausgrid prepares detailed forecasts for each substation which include both short term spatial and long term econometric factors, and does not use a single linear p.a. growth rate for planning purposes. This growth rate is therefore derived to achieve the expected maximum demand at each substation in accordance with Ausgrid's base spatial forecast for the 2018/19 year.

Table 2.4.4 – Distribution Substations

Forecast growth in Distribution Substation augmentations has been derived from historical overload data and a 'steady state' volume of overloads is derived. Since Distribution Substation overloads are the result of localised growth, augmentation is not related to maximum demand forecasts. This is outlined in Supporting Document ID60868 Low Voltage Capex model Method and Outcomes (explanatory).

b) In relation to the capex-capacity table (table 2.4.6), Ausgrid must explain:

> **i. the types of cost and activities covered. Clearly indicate what non-field analysis and management costs (i.e. direct overheads) are included in the capex and what proportion of capex these cost types represent;**

Capex reported in this area includes direct costs and direct overheads or indirect costs. These costs predominantly reflect divisional management & attributable support costs. Overall these costs represent approximately 16% of total capital costs.

> **ii. how it determined and allocated actual capex and capacity to each of the segment groups, covering:**
>
>> **A. the process used, including assumptions, to estimate and allocate expenditure where this has been required; and**
>>
>> **B. the relationship of internal financial and/or project recording categories to the segment groups and process used.**

The method used to determine & allocate costs to each of the segment groups is outlined in the Basis of Preparation for Table 2.4.6. In summary;

- Sub-Transmission Lines capex & capacity is directly allocated to this category.
- Capex & Capacity for Zone & ST Substations are allocated on the basis of the allocation substations in Table 2.4.4.
- Actual HV Feeder & Distribution Substation Capex (including land and easement costs) & Capacity is based on data in Table 2.4.4 and allocated on the basis of the combined rate of growth of each associated feeder category.
- Unmodelled augmentation is the net remainder of the total in Table 2.3.4.

> **iii. how it determined and allocated estimated/forecast capex and capacity to each of the segment groups, covering:**
>
>> **A. the relationship of this process to the current project and program plans; and**
>>
>> **B. any other higher-level analysis and assumptions applied.**

Subtransmission Lines, Subtransmission Substations and Zone Substations

Capacity Added is derived from the latest Sub-transmission Planning project review (2012/13 forecast review). It is based on the estimated completion time for projects as of that review (Dec 2013).

HV Feeders

Ausgrid does not record the actual number of 11kV feeders added to the network. A manual comparison of the trunk feeders was done by reviewing the System Diagrams published as of 1/7/2012 and as of 9/5/2014 and the differences manually read off diagrams. Any new or removed feeder was identified and the ratings in 11kV amps for both summer and winter were recorded off the diagrams. Additional feeders that were expected to be formed between 9/5/2014 and on or before 30/6/2014 were gathered from existing projects (DNP/DBs) (advice provided by the Field Services). Their ratings were calculated based on the expected cables and configuration in the project documentation. Double banked feeders were counted as 2 separate individual feeders. Feeders that did not exit the substation were not included e.g. Aux, FIU, Cap Banks. The feeders were then classified based on the four feeder type classifications (CBD, Urban, Short Rural, Long Rural). The classifications came from the reliability group's classification of the feeders as at 1/7/2012 and their last available classification identification done on the 31/12/2013. Feeders that did not have an identified classification (e.g. new feeders) were given one based on the current planning criteria definitions. Where feeder category was not available the feeder load / length and load type and surrounding feeder classifications were used to assign feeder category. Conversion to MVA of 5kV and 11kV loads used nominal voltages of 11000V and 5000V respectively. It was not possible to obtain the Net capacity added (MVA) "For customer-initiated & capacity-related augmentation" or "For NSP-initiated & capacity-related augmentation", as this data is not recorded and cannot be estimated to a reasonable level.

Distribution Substations

The net MVA capacity added to each network segment is determined by the commissioned and decommissioned substations associated with that segment in the financial years indicated. The MVA information for 2013/14 financial year is scaled based on the known expenditure and asset information at the end of February 2014 and the expected expenditure for the financial year.

The information for customer initiated augmentation is included in the connections RIN tables and is not reproduced in this table.

c) Describe the types of projects and programs Ausgrid has allocated to the unmodelled augmentation categories in table 2.4.6, covering:

i. the proportion of unmodelled augmentation capex due to this project or program type;

ii. the primary drivers of this capex, and whether in Ausgrid's view, there is any secondary relationship to maximum demand and/or utilisation; and

iii. whether the outcome of such a project or program, whether intended or not, should be an increase in the capability of the network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level.

Unmodelled capital expenditure represented around 15% of capex prior to 2012/13 but is forecast to decline to 0.6% in 2018/19. This mostly comprises system property, communications and IT requirements.

The primary driver of this expenditure was a combination of forecast growth and network security considerations.

The outcome of this expenditure assisted in increasing the capability of the network to supply customer demand

d) Separately for each network segment that Ausgrid defined in the model segment data table (2.4.5):

i. Describe the network segment, including:

A. the boundary with other connecting network segments; and

B. the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment).

Sub-transmission and Zone

Segment 1: Sub-transmission Feeders (Sydney)

Segment 2: Sub-transmission Feeders (Hunter/Central Coast)

Segment 3: Sub-transmission & Zone Substations (Sydney)

Segment 4: Sub-transmission & Zone Substations (Central Coast)

Zone, STS and Sub-transmission feeders have been broken into two segments per group on a geographical basis. This is designed to broadly reflect the different network designs and operating conditions. The two areas are Sydney area networks and Hunter/Central Coast network areas. The primary differences are:

- The Sydney area feeder networks are predominantly shorter UG feeders compared to long OH networks in the Hunter and Central Coast.
- Sydney Substations are on average larger capacity with more transformers, resulting in a higher utilisation threshold and lower $/MVA than Hunter/Central Coast substations.
- There are differing average growth rates between the two areas.

HV Feeders

HV Feeders are segmented according to Table 2 of the AER Augmentation Model Handbook. In addition, the urban category is further segmented into the geographical network areas as listed above. Feeders are classified based on the definitions of CBD, Urban, Short Rural and Long Rural feeders types in the NSW DNSP Licence Conditions.

In summary, the network segments for the HV feeders are:

- CBD
- Urban – Sydney
- Urban – Hunter and Central Coast
- Short Rural
- Long Rural

In the urban category, the primary differences between the HV networks in these areas are:

- The Hunter and Central Coast (CC) HV feeder networks are generally less developed, higher utilised and more radialised than feeders in the Sydney network.
- There are more spare feeder panels in the Hunter and Central Coast network areas.
- There are more greenfield developments in the Hunter and CC HV feeder networks. Especially areas transitioning from rural to urban load type.
- The cable routes in Sydney are heavily congested.
- Sydney augmentation typically involves reinforcing or upgrading the existing network, in the Hunter and CC there is a more frequent need/feasibility of commissioning new feeders.

The differences above result in higher $/MVA and capacity factor for Sydney augmentation works in comparison to Hunter and CC augmentation works.

The feeder categories were not further segmented to prevent small sample size in the calculation of planning parameters.

Ausgrid notes, however, the Long Rural feeder category suffers from small sample size.

Distribution Substations

The network segments used for Distribution Substations are the highest aggregation possible under the AER's model guidelines. Each substation is allocated to a segment based on the category of the HV feeder supplying it with the exception that all Urban feeders are combined.

The large variability in the solutions applied for capacity constraints on Distribution Substations and the downstream LV network makes any further detailed segmentation counter-productive given the high prevalence of load transfer within the segment and the minimal correlation between the model's planning parameters and actual practice.

ii. Explain the utilisation threshold statistics provided (i.e. the mean and standard deviation), including:

A. the methodology, data sources and assumptions used to derive the parameters;

B. the relationship to internal or external planning criteria that define when an augmentation is required;

C. the relationship to actual historical utilisation at the time that augmentations occurred for that asset category;

D. Ausgrid's views on the most appropriate probability distribution to simulate the augmentation needs of that network segment; and

E. the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the network segment.

Zone Substations and STS

Source data for Utilisation Threshold is contained in RIN Section 2.4 and additional Licence Capacity Data is sourced from Ausgrid's Network Forecasting Team. Historical thresholds are indicative only, as past practice was to combine substation and feeder limitations into the Substation Licenced Capacity limit. Therefore some manual correction and estimation of data was required.

For Zone Substations and STS: Utilisation Threshold is derived from the relationship:

"Licence Capacity" / "Normal Cyclic"

Where Normal Cyclic is the installed *usable* capacity at a zone or STS, and "Licence Capacity" is the N-1 rating Ausgrid uses to determine investment triggers. Historically this has been based on the NSW Distribution Licence Conditions, which for many assets include an allowance for probabilistic risk (up to 20% or 10 MVA over firm N-1 capacity).

Sub-transmission Feeders

This is derived from two relationships:

- The relationship between the N loading and N-1 loading (in MVA) to determine the ratio between system normal and worst-case credible contingency loading, and
- "Licensed Capacity" and "Normal Rating", where "Licensed Capacity" is the emergency rating of a feeder in MVA (at nominal volts), plus 20% if it is an overhead feeder, and "normal rating" is as per the data provided in Table 2.4.1.

Utilisation Threshold = (N loading / N-1 loading) * (Licensed Capacity / Normal Rating)

The first relationship defines the level of utilisation under system normal that would correspond to the limiting condition under contingency analysis, and the second provides a conversion to relate the normal cyclic ratings used in the Augex model to the risk-based criterion (including where applicable both the use of emergency ratings and the additional probabilistic risk allowance of 20% for OH feeders under the NSW Licence Conditions).

This data is sampled from the Feeder Forecast results done by Area Planners.

HV Feeders

Utilisation Threshold is sourced from the analysis of 161 distribution network projects (DNPs) issued between 2008/09 and 2013/14. For each project, the utilisation of each feeder proposed to undergo augmentation (at the time of the proposal) is averaged to derive a 'project utilisation threshold'.

Each project utilisation threshold is then used to calculate a weighted mean utilisation threshold for a network segment (weighted by the project estimate):

$$\overline{x} = \frac{\sum_{i=1}^{n} w_i x_i}{\sum_{i=1}^{n} w_i} \qquad \sigma = \sqrt{\frac{\sum_{i=1}^{n} w_i (x_i - \overline{x}\,)^2}{\sum_{i}^{n} w_i}}$$

Where:

- ¯ is the weighted average of project utilisation thresholds (i.e. segment utilisation threshold)
- is standard deviation
- is the project utilisation of the i-th project in a network segment
- is the project estimate of the i-th project in a network segment
- n is the total number of projects in a network segment

Distribution Substations

The document "Inv-STD-10034 LV Planning " in "Section 6 - Investment Planning" states that:

"A planning investigation is initiated:

- *For MDI or DM&C data, if the load is measured ≥ 100% of the rating*
- *For load survey data, if the load is measured ≥ 95% of the rating*

For this purpose, distributor ratings are generally based on the fuse panel rating (refer to 7.1) unless available information indicates that the downstream elements of the distributor are loaded over their rating."

Given that the majority of distribution substation load readings are taken via MDI the utilisation threshold for a distribution substation is 100% of the substation rating.

The load survey programme allows for an average time between reads of 6 months. Therefore the maximum time for identification of a threshold breach is 6 months for most substations. Supporting Document Low Voltage planning manual (ID81963) states under section 3 that "remedial actions to ensure that the thermal capacity of the network is not exceeded are completed (where possible) before the next peak season". This allows for a target maximum of 12 months between the identification and rectification of a threshold breach giving a total theoretical maximum time between the breach of the threshold and the completion of rectification works of 18 months. During this 18 month period the maximum demand growth is therefore expected to be 1.5% (based on a maximum demand growth of 1% p.a.).

The actual time between identification of a threshold breach and the completion of works to rectify the issue will depend largely on the volume of works currently in progress and the severity of the breach. However, the magnitude of any threshold breach is expected to increase by approximately 1.5% on any given base utilisation before being rectified.

Assuming that the threshold breach is identified immediately after it occurs and that all breaches occur due to linear load growth, the standard deviation of the utilisation threshold is assumed to be 1.5% due to the demand growth escalation above.

In reality, the increase in maximum demand on a distribution substation is rarely linear and hence the magnitude of a threshold breach is highly variable and depends on the general and spot growth in a given area. As such, the exact degree to which the utilisation threshold is breached by any given overload is not able to be determined with any accuracy.

Ausgrid's views on the most appropriate probability distribution to simulate the augmentation needs of its network segments, and the process applied to verify the parameters are a reasonable estimate of utilisation limits for the network segments have been addressed in section 4.5 of the Basis of Preparation.

iii. Explain the augmentation unit cost and capacity factor provided, including:

A. the methodology, data sources and assumptions used to derive the parameters;

B. the relationship of the parameters to actual historical augmentation projects, including the capacity added through those projects and the cost of those projects;

C. the possibility of double-counting in the estimates, and processes applied to ensure that this is appropriately accounted for (e.g. where an individual project may add capacity to various segments); and

D. the process applied to verify that the parameters are a reasonable estimate for the network segment.

Sub-Transmission and Zone

The Augmentation unit costs and capacity factors have been derived from historical data of projects completed in the current regulatory submission. As has previously been raised, the derivation of project related planning parameters for asset categories with small populations of non-uniform assets *and* non-uniform solutions to growth drivers (particularly sub-transmission lines, zone substations, and STS) is difficult. It is not possible to derive statistically meaningful parameters for Augmentation Unit Cost and Capacity Factor based on the both the historical and forward-looking project sets which comprise augmentation driven works at this level of the network with any level of accuracy. As noted in the AER augmentation model handbook, sample size is very important for statistical modelling, and the lack of samples (less than 30 per segment group) in the capacity augmentation area for sub-transmission and zone segment groups mean that these variables can only be considered indicative, particularly for the forecast period going forward.

The numbers provided in Table 2.4.6 are based on historical real project costs (in real 2012/13 dollars) from last regulatory period (and the associated “capacity added”), and escalated assuming 0.3% real cost escalation over 5 years (1.5%) for the upcoming regulatory period. An estimate of indirect overheads of 10% has been made which is then removed from the resultant unit rate.

For each sample project parameters are derived from the following relationship:

Capacity Factor = [Capacity Added] / [Existing Capacity]
or alternatively expressed as ([New Capacity] – [Existing Capacity]) / [Existing Capacity]

$/MVA (forecast) = ([Project Cost]*1.015*0.9) / [Capacity Added]

$/MVA (historical) = ([Project Cost]*0.9) / [Capacity Added]

An average value is then taken for each segment group.

Only sample projects where there were clear substation and feeder cost components were used to develop these estimates, to ensure no double-counting occurred.

It was found that capacity factor is very sensitive to the sample of projects used, particularly in these segments with very small sample populations. Many augmentation solutions at this level of the network are unique, driven by existing network design and constraints. No forecast capacity factor is possible due to the lack of upcoming projects driven by augmentation requirements in the upcoming submission. To validate these results, a number of other approaches have been examined, including an assessment of typical feeder and substation configurations and using calibration techniques to simulate model output compared to past activity.

HV Feeders

The unit cost is calculated by totalling the sum of the expenditure of the projects in a network segment, divided by the sum of the increase in capacity proposed by those projects in MVA. The expenditures were sourced from the list of 161 DNPs, with the data extracted from SAP. To achieve better accuracy, actual spends were used for closed (completed) projects and the estimate is used for released (ongoing) projects.

Capacity Factor is sourced from the same list of 161 DNPs issued between 2008/09 and 2013/14. For each project, the existing and proposed capacities of the feeders proposed to undergo augmentation are used to calculate the capacity factor of each project. The weighted average is calculated with the same formula as above, except utilisation is replaced by capacity factor. Non-trunk augmentation projects (with capacity factor of zero) are included in the calculation of the average. On the rare occasion when a project addresses both urban and rural feeders, a decision is made to allocate the project to one segment based on which load type received the most investment in the proposal.

Distribution Substations

The $/MVA figure for each network segment is derived from a correlation between project cost and the transformer capacity installed for projects related to augmentation. A total of 625 completed augmentation projects in the 2009/14 regulatory period contained the required cost and asset data. These projects were split into their corresponding network segments using the associated 11kV feeder category of the associated distribution substation (as outlined under Table 2.4.4).

The total project cost in each network segment is then divided by the total MVA installed by these projects to determine the $/MVA for the segment. The value was then cross checked against the known expenditure under the relevant regulatory programs.

Note that all $/MVA calculations are based on the MVA as calculated off the assigned ERP SAP rating of the substation rather than the nameplate capacity of the transformer. In particular, this results in a high substation rating for smaller capacity single phase PTs (predominantly found on Short or Long Rural feeders) whose rating is based on a domestic load cycle. This also impacts the Capacity Factor for the short and Long Rural categories.

The capacity factor for the Urban, CBD, and Short Rural network segments is calculated based on an analysis of the scope of typical capacity driven augmentation projects across these segments combined with actual project numbers across the first four years of the current regulatory period. This information was taken from data used for cost of delivery analysis. The project types used in the cost of delivery analysis were correlated with a typical scenario for augmentation with a corresponding capacity factor. The number of each project type for one financial year and the corresponding capacity factor were used to calculate the capacity factor for the full network segment. This value is assumed to be representative of all other financial years requested for these segments.

The exception to this approach was for the Long Rural segment for which the project information mentioned above was not sufficient. The capacity factor for this segment was calculated based on a sample of typical actual projects undertaken in this regulatory period.

e) Explain the significant factors Ausgrid considers may result in different augmentation requirements between itself and other NEM DNSPs, faced with similar asset utilisation and maximum demand growth. Clearly differentiate between those factors that may result in differences between Ausgrid and other DNSPs in the NEM. The explanation should clearly indicate those factors that may impact:

i. the maximum achievable utilisation of assets for Ausgrid; and

ii. the likely augmentation project and/or cost.

For each significant factor discussed, Ausgrid must indicate relevant model segments and estimate the impact these factors will have on its augmentation levels and associated capex compared to other DNSPs.

Note it is not possible to quantify the impact these factors will have in comparison with other DNSPs, as this would imply an understanding of the factors affecting other DNSPs. The following is a summary of major factors affecting costs, including unique features of the Ausgrid system when compared to other NSW and interstate DNSPs.

1. Jurisdictional Planning Criteria

Distributors in NSW have been bound since 2008 to the NSW Distribution Licence Conditions, which provided prescriptive deterministic criteria (inclusive of some probabilistic elements for overhead sub-transmission feeders and zone substations). Ausgrid in particular had a special obligation to comply with a Sub-transmission N-2 criterion in the Sydney CBD, which although a common criterion in other major global cities, is unique within Australia. These conditions therefore impose limitations on asset utilisation under system normal which may not be imposed on other jurisdictions in the NEM.

These factors also affect the joint transmission network planned between Ausgrid and TransGrid, which covers a heavily meshed 330kV and 132kV system. Planning criteria outlined in the NSW Industry and Investment transmission reliability standards require additional security of supply for the Inner Metropolitan Area (defined as the network supplied by TransGrid BSPs Sydney North, Sydney South, Beaconsfield and Haymarket), known as

"Modified N-2". This requirement, coupled with the unique meshed arrangement with radial 330kV supplies feeding the inner city area, result in very low system normal load flows on some 132kV feeders, as they are sized to compensate for the loss of much higher capacity 330kV supplies under contingency scenarios. As these feeders are high capacity and high value, they can distort comparisons with other DNSPs which do not have a similar type of network.

In addition, due to high security standards, particularly in the Sydney CBD, these assets may appear underutilised under normal conditions.

2. *Geographic & Demographic factors*

Ausgrid has an extremely varied geographic area and customer distribution, ranging from Muswellbrook and Scone in central NSW to the Sydney CBD and Eastern Suburbs. This variation means vast differences in load density and construction requirements and suggests overall benchmarking of Ausgrid costs may be difficult. For example, the Sydney CBD has a load density of over 160 MVA/km2 compared to 0.009 MVA/km2 in the Upper Hunter area, resulting in completely different challenges and cost structures for these areas.

Assets in denser suburban areas generally cost more than an equivalent asset installed in a less dense environment. Space to install assets is limited, and access to install and maintain assets is complex. In addition, assets in suburban and inner city areas generally must be installed indoors and underground. Due to these complexities it is often cost effective to make allowances for future expansion when installing new assets. Examples of this include installation of spare UG cable ducts, or installation of extra circuit breakers and purchasing of extra land at zone substations to cater for longer term expansion or refurbishment requirements. Conversely construction in the Upper Hunter is almost exclusively overhead and outdoor, with challenges of distance and low density being the main issues.

A further key unique geographic factor affecting the Ausgrid network is the complex ria (drowned river valley) geography in the supply area, including the Sydney Harbour, Georges River and the Hawkesbury River. This geography is unique in the Australian context for a heavily urbanised area, and these natural barriers, including the surrounding sandstone cliffs and valleys, create significant additional costs for construction. This is compounded by large areas of protected vegetation (e.g. National Parks) around these areas. These factors are not shared by other urban distributors within NSW and the wider NEM.

Other factors that affect the cost of projects for Ausgrid in urban areas include typically higher re-instatement costs and temporary reinstatement requirements. This is due to the prevalent use of reinforced concrete pavements in the Sydney Metro area, which are more frequently used in Sydney than elsewhere in NSW and interstate.

Many areas in the Ausgrid distribution network have seen rapid development due to various demographic factors. The Lower Hunter area (near Maitland) have experienced rapid developments with rural areas being converted into urban residential areas to cater for demands on housing driven by mining activities in the Hunter region. The injection of mining investments in the area has also driven urban renewal and gentrification in Newcastle and its suburbs. The Central Coast is also a growth area, as high housing demands in Sydney and increased work opportunities in the Hunter drive people to reside in the area.

While Ausgrid acknowledges that other DNSPs have similar demographic changes in their supply area (e.g. urban residential developments in Western Sydney), it is believed that the combination of push and pull factors in the Central Coast and Hunter areas result in scales and rates of change that are unique to Ausgrid's network area.

3. *Network Factors (Historical and Design)*

One of the biggest factors affecting augmentation projects, costs and the resultant network utilisation are the historical design decisions and legacy systems which exist on the network.

The Ausgrid system is a combination of 132kV, 66kV, 33kV and 11kV assets. This historical configuration can lead to non-optimum sizing of assets. For example, installation of 132kV feeders to supply a single zone substation may be the most cost effective option, but results in apparent under-utilisation of the capacity of even small 132kV cables. This may be more prevalent in predominantly underground networks where the number of available cable sizes is relatively small when compared to OH conductor, and future "up-rating" of assets is very costly or impossible.

This is particularly evident during a period of asset renewal and replacement, where older, more heavily utilised assets are replaced with modern equivalent assets. In many cases the modern equivalent is larger capacity than legacy designs because of current economies of scale in procurement and where the cost differential between different sizes is small. Brownfield area development with modern standard assets may also result in a capacity mismatch between existing assets, such as 11kV trunk feeder capacity. This may limit future utilisation capabilities.

Brownfield developments will also affect unit costs. Augmenting an old legacy zone, for example, may require upgrades to protection and communication schemes which would otherwise not be required. Land costs can also be a big component, particularly in high density areas where available land is limited and expensive.

Ausgrid's urban HV feeder network is in general older than that of other DNSPs. It has been constructed with tapering conductor rating away from the zone substation. As load demand increases, it was observed in many cases that non-compliances downstream of the trunk triggered feeder augmentation. As acknowledged in Section 5.1.3 of the AER Augmentation Model Handbook, this has the effect of increasing the unit cost; with non-trunk augmentation allowing the trunk utilisation threshold to be increased. However the benefits of the augmentation would not be realised until the time augmentation is triggered.

The existence of Ausgrid's well established network also makes augmentation work difficult. The existing zone substations have limited number of available feeders for new connections. Cable routes are congested and acquisition of new easement is generally not feasible. Therefore, in many cases new feeders are prohibitively expensive or infeasible on Ausgrid's network. Augmentation is often restricted to upgrading existing feeders and reconfiguring. Such projects have low capacity factor, but achieve compliance without necessarily increasing trunk capacity.

Additional Reset RIN Requirement

Ausgrid notes that Appendix E Section 8.3 Table 2.4.2 instructions require Ausgrid to provide the following:

a) In a separate document, explain how the asset rating values reported in the table were determined. Where relevant, this explanation should include:

> **i) The basis of the calculation of the ratings reported, including asset data measured and assumptions made.**
>
> **ii) How the ratings reported for the same assets may be used in *augmentation* planning and/or the operation of the distribution *network*.**
>
> **A) If alternative ratings are used in *augmentation* planning and/or the operation of the distribution *network*, explain and define these alternative ratings.**

Ausgrid Ratings & Impedance Standard is outlined in Supporting Document ID26254 (INV-STD-10026) Planning Standard - Ratings and Impedances of Network Assets. This standard references separate detailed processes for:

- Transformer & Substation
- Sub-Transmission Feeders
- Distribution Substations & Low Voltage Cables.

8. DEMAND AND CUSTOMER NUMBER FORECASTS

8.1 Provide and describe the methodology used to prepare the following forecasts:

(a) maximum demand; and

The methodology used to prepare the maximum demand forecast is detailed in Attachment 5.04 - (INV-STD-10022) Planning Standard - Demand Forecast & related documents, provided as part of Ausgrid's regulatory proposal to the AER.

(b) number of new connections.

The methodology used for forecasting the number of new connections is outlined in Supporting Document ID68852 Customer number forecast methodology. Forecasts have been based on an established relationship between building construction activity and new connections.

8.2 Provide:

(a) the model(s) Ausgrid used to forecast customer numbers and maximum demand;

Ausgrid's model used to forecast **maximum demand** is built in SAS. Ausgrid's previous model used to forecast maximum demand existed in the form of hundreds of spreadsheets linked using Visual Basic code which was very cumbersome, involved extensive manual processes and was very difficult to debug. Whilst the outputs of the forecast are printed to Excel spreadsheets, the internal calculations are carried out and stored within the SAS software. Ausgrid has no objections to the AER reviewing the SAS forecasting system in person and the data contained therein should the AER require.

The models used to forecast **customer numbers** are provided as supporting documents for Ausgrid's regulatory proposal, as follows:

- Supporting Document ID68852 2014 05 12_Customer Number Forecast Methodology
- Supporting Document ID32532_Customer Number Forecasts Model

(b) where Ausgrid's approach to weather correction has changed, provide historically consistent weather corrected maximum demand data, as per the format in regulatory templates 5.3 and 5.4 using Ausgrid's current approach. If this data is unavailable, explain why;

Regulatory templates 5.3 and 5.4 contain historically consistent weather corrected maximum demand data using Ausgrid's current approach as explained in the Attachment 5.04. Please note that each time the forecast is produced (annually) historical weather corrected maximum demand must be re-calculated due to the inclusion of new weather data.

(c) for number of new connections, volume data requested in regulatory template 2.5; and

This information has been provided in regulatory template 2.5, and the corresponding sections of the Basis of Preparation document.

(d) any supporting information or calculations that illustrate how information extracted from Ausgrid forecasting model(s) reconciles to, and explains any differences from, information provided in regulatory templates 2.5, 5.3 and 5.4.

The supporting information or calculations that illustrate how information extracted from the Ausgrid forecasting model reconciles with Regulatory templates 3.4, 5.3 and 5.4 is explained in the Basis of Preparation.

Supporting information for the completion of regulatory template 2.5 is provided in Supporting Document ID68852 2014 05 12_Customer Number Forecast Methodology.

8.3 For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain:

(a) the models used;

For maximum demand, the methodology used to prepare the maximum demand forecast is detailed in Ausgrid's Attachment 5.04.

For customer connections, please refer to the response in section 8.2(a)

(b) a global (or top-down) and spatial (bottom-up) forecasting processes;

The top-down and bottom-up forecasting processes used in the **maximum demand** forecast are contained in the methodology document provided in Attachment 5.04 to Ausgrid's regulatory proposal.

Ausgrid's **customer numbers** forecasts utilise a bottom up process. More detail is provided in Supporting Document ID68852.

(c) the inputs and assumptions used in the models (including in relation to economic growth, customer numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions);

For maximum demand, the inputs and assumptions used in the long term growth rate model, which affects the long term growth rates in the maximum demand forecast, are described in Attachment 5.04.

For customer numbers, please refer to the response in section 8.2(a).

(d) the weather correction methodology, how weather data has been used, and how Ausgrid's approach to weather correction has changed over time;

The weather correction methodology, and how the weather data is used, is described in Attachment 5.04.

Prior to 2009, weather correction was not carried out by Ausgrid. From 2009 to 2011, a weather correction process was developed that involved raising the load vs temperature trendline to coincide with the maximum observed daily load point. After 2011, a more sophisticated Monte Carlo simulation based weather correction methodology was implemented.

(e) an outline of the treatment of block loads, transfers and switching within the forecasting process;

The treatment of block loads, transfers and switching is detailed in Attachment 5.04.

(f) any appliance models, where used, or assumptions relating to average customer energy usage (by customer type);

Assumptions relating to customer energy usage in the residential customer segment, which forms part of an end-use model, are described in Attachment 5.04.

(g) how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load on the system and substations);

The forecasting methodology uses historical observations (interval demand data) and includes calibration processes that remove the effect of abnormal loads such as switching and spikes and normalises the maximum demands against a weather set. This process is described in Attachment 5.04.

(h) how the resulting forecast data is consistent across forecasts provided for each network element identified in regulatory template 5.4 and system wide forecasts;

The supporting information or calculations that illustrate how forecast data is consistent across forecasts provided for each network element in Regulatory templates 5.3 and 5.4 is explained in the Basis of Preparation.

(i) how the forecasts resulting from these methods and assumptions have been used in determining the following:

(i) capital expenditure forecasts; and

Please refer to the answer provided in section 8.2(a).

(ii) operating and maintenance expenditure forecasts.

The forecast opex for the 2014-19 period has not explicitly accounted for increases in costs associated with maximum demand and new customer connections forecasts. Nevertheless, some specific opex categories have indirectly incorporated the impact of the above factors as outlined below.

- **Demand Forecast & Maximum Demand:** in developing the forecasts for Demand Management programs, the demand forecast and maximum demand were taken into consideration when determining the appropriate broad based demand and demand management programs to implement over the next regulatory period to control load and assist in deferring capex into the future;
- **New Customer Connections:** the main opex cost category that may be impacted by new customer connections is Data Operations which is the business unit responsible for the processing of applications and site information. Ausgrid's forecast opex for Data Operations however has not included any incremental opex to account for possible growth in new customer connections as these would be absorbed within the existing resources.

(j) whether Ausgrid used the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal;

Ausgrid uses the maximum demand forecasts as described above as a key input into joint planning processes. The outcomes of joint planning are reflected in Ausgrid's regulatory submission.

(k) whether Ausgrid forecasts both coincident and non-coincident maximum demand at the feeder, connection point, subtransmission substation and zone substation level, and how these forecasts reconcile with the system level forecasts (including how various assumptions that are allowed for at the system level relate to the network level forecasts);

Ausgrid forecasts the non-coincident maximum demand at the zone substation and subtransmission substation level and calculates diversity (coincidence) factors to enable the coincident maximum demand at the network level to be derived. The maximum demand forecast at the feeder level is calculated using loadflow techniques based on the maximum demand forecast at the subtransmission substation and zone substation level.

Ausgrid considers "connection point" as meaning transmission connection point and has interpreted this, in respect to its network, as being comprised of all subtransmission substations, zone substations connected at 132kV and high voltage customers connected at 132kV as outlined in its response to the Economic Benchmarking RIN. This is not the same as the coincident maximum demand at the network level, which has specific inclusions such as 33kV embedded generators and non-132kV substations supplied from Endeavour Energy's network and exclusions of other major customer connected directly to the transmission network. Furthermore, Ausgrid does not forecast at the connection point level since there is no business purpose for this forecast, other than to satisfy RIN requirements. The forecasts at the zone substation, subtransmission substation and feeder levels are produced since they are directly utilised by Ausgrid for network planning purposes.

The forecast at the zone substation and subtransmission substation level incorporates macro variables at the regional level in Ausgrid's network area, where the regional data comprises key variables such as projected residential customer numbers, projected changes in disposable income and retail electricity prices, expected impacts of ongoing solar PV penetration, expected impacts of the NSW Energy Savings Scheme and projected air conditioning penetration rates. These variables influence the individual substation growth rates from the 4^{th} year onwards.

(l) whether Ausgrid records historic maximum demand in MW, MVA or both;

Ausgrid records historic interval demand data in various units (amps, MW, MVA, MVAr, pf). Maximum demand is then calculated from the interval data after appropriate measures are taken to filter out abnormal loads such as switching and data spikes. Conversions between MW, MVA etc are carried out using standard formulas.

(m) the probability of exceedance that Ausgrid uses in network planning;

Ausgrid uses a 50% probability of exceedance in its network planning. This is a requirement stipulated in the Licence Conditions.

(n) the contingency planning process, in particular the process used to assess high system demand;

Ausgrid develop 'firm ratings' and 'licensed ratings' for substations which include an assessment of the worst case substation contingency (e.g. transformer failure) when determining network constraints under high system demand.

Ausgrid undertake load-flow analysis on transmission and sub-transmission feeders to identify constraints under the relevant planning criteria (e.g. N, N-1, N-2, Modified N-2, risk etc). This analysis is done using models based on the 50% POE forecasts developed by Ausgrid.

(o) how risk is managed across the network, particularly in relation to load sharing across network elements and non-network solutions to peak demand events;

The NSW license conditions (effective until July 2014) contained requirements for the application of risk in determining network constraints. Ausgrid's approach to this is described in Planning Standard INV-STD-019 Area Planning.

As part of our investment governance process, for every capex project greater than $1m a review is carried out to determine whether it would be cost-effective to defer the investment through the implementation of non-network solutions. This is assessed as part of the area planning process, and also for individual projects as appropriate. Where non-network projects identified in the investigation process are determined to be cost effective, they are implemented and the associated capex project is deferred. Further details on this process are provided in Attachment B of Attachment 6.12 Demand Management Opex Plan to the regulatory proposal.

Load-sharing across network elements is managed across planning, design, procurement and operations. Some examples include (but not limited to) specification of line reactors to control power flow on parallel paths, design of auto-close schemes to manage transformer / circuit loading under contingencies, specification of transformer impedances, and pre- and post-contingent network switching to manage network loading under various system configurations. Thus a multi-faceted approach is adopted by Ausgrid to maximise asset utilisation under a variety of operating conditions.

(p) whether and how the maximum demand forecasts underlying the regulatory proposal reconcile with any demand information or related planning statements published by AEMO, as well as forecasts produced by any transmission network service providers connected to Ausgrid's network;

Ausgrid's spatial forecast utilises NIEIR data as the basis for post model adjustments and so in this regard, does not reconcile with forecasts published by AEMO. An explanation of the differences between Ausgrid's and AEMO's forecasting methodology is provided in Attachment H Differences Between Ausgrid and AEMO Spatial Demand Forecasting Methodologies.

(q) how the normal and emergency ratings are used in determining capacity for individual zone substations and sub-transmission lines;

The substation ratings shown in 5.4 'Maximum Demand and Utilisation at spatial level' is the Firm rating of the substation. The firm rating is typically based on the emergency rating of the transformer throughput groups. The Firm rating allows for a single contingency transformer outage.

For details on how this value is derived for the different zone substation configurations is provided in Supporting Document ID38478 Standard - Reliability Planning Individual Feeder (INV-STD-10027).

The circuit capacities provided in 3.5.1 are based on the summer normal line ratings.

(r) where Ausgrid proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder:

(i) for each feeder from the zone substation that is the connecting zone substation for the relevant HV feeder, and any other feeders that the relevant HV feeder can transfer load to or from:

(A) assumed future load transfers between feeders;

For continued capex projects where the exact location of the constraints and solutions are identified, the future load transfers between HV feeders are based on a bottom up analysis to meet acceptable planning criteria.

For yet to commence capex projects where the exact location of the constraints are unknown, it is assumed that 100% load transferability is achievable between each HV feeder within the same zone substation up to the average theoretical maximum utilisation for each HV feeder within that zone substation.

(B) assumed feeder underlying load growth rates (exclusive of transfers and specific customer developments); and

The HV feeder underlying load growth rates are based on the load growth rates derived from the maximum demand forecast of the associated zone substation. The maximum demand forecast used for this purpose specifically excludes future load transfers and major projects.

(C) assumed block loads, and associated demand assumptions;

Assumed block loads and associated demand assumptions are as outlined in the Attachment 5.04.

(ii) existing embedded generation capacity, and associated assumptions on the impact on demand levels;

Existing embedded generation and associated assumptions are as outlined in Attachment 5.04.

(iii) assumed future embedded generation capacity, and associated assumptions on the impact on demand levels;

Assumed future embedded generation and associated assumptions are as outlined in Attachment 5.04.

(iv) existing non-network solutions, and the associated assumptions on the impact on demand levels;

Existing non-network solutions and associated assumptions are as outlined in Attachment 5.04.

(v) assumed future non-network solutions, and associated assumptions on the impact on demand levels; and

Future non-network solutions and associated assumptions are as outlined in Attachment 5.04.

In addition to the assumptions outlined in Attachment 5.04 indicative financial impacts of project specific non-network solutions are also included based on historical information.

(vi) the diversity between feeders;

The diversity between HV feeders are derived from a relationship between the maximum demand sum of all HV feeders in the same zone substation to the maximum demand of the zone substation itself in the same year/season.

(s) where Ausgrid proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a zone substation (or relevant substations for a sub-transmission line):

(i) assumed future load transfers between related substations;

The potential for 11kV load transfers as a demand-related capex project (or to defer a demand-related capex project) is assessed by planners at the area planning stage, and reviewed annually.

(ii) assumed underlying load growth rates (exclusive of transfers and specific customer developments);

Ausgrid uses the established substation forecasts provided in RIN Section 5.4 ("base forecast") as the starting point, with further modifications to reflect expected changes to the network due to other major projects or customer connections ("development forecast"). This forecast is used to determine the need for demand-related capex. This process is described in Attachment 5.04.

The base forecast includes an underlying substation-specific growth rate, with some specific customer developments and demand assumptions added on top where there is sufficient probability that they will proceed. This forecast methodology is described in Attachment 5.04.

(iii) assumed specific customer developments, and associated demand assumptions;

See 8.3(s)(ii). Specific customer developments are included in the demand forecast as spot loads, and are based on the projected demand information provided to Ausgrid by the customer which is reviewed to include relevant diversity factors, and a probability factor is also applied to reflect the likelihood of the demand increase occurring at the specified time.

(iv) existing embedded generation capacity, and associated assumptions on the impact on demand levels;

See 8.3(s)(ii). Existing embedded generation that is operational during peak demand events lowers the historical peak demand data, which therefore reduces the projected peak demand growth rates (as these are based on the historical data). In a few specific cases, where a large embedded generator does not meet the reliability requirements suitable for network support for planning purposes, any impact of the generator on historical peak demand is removed in the forecasting process.

(v) assumed future embedded generation capacity, and associated assumptions on the impact on demand levels;

See 8.3(s)(ii). Future uptake of solar PV and also energy efficiency programs are included in the demand forecast. Projections of future impacts from solar PV & energy efficiency were developed in partnership with external consultants, and these have been included as a post model adjustment to our forecast. Using standard profiles for rooftop solar systems, we assume that 35% of the rated capacity is effective at the typical time of network peak (4pm AEST). To derive the demand impact from the estimated volume impacts from energy efficiency, estimated peak conversion factors were applied to the various energy efficiency programs (e.g. MEPs, BCA).

For future larger scale embedded generators (e.g. cogeneration plant), we make no adjustments in the demand forecast unless there is a specific agreement with the generator owner to operate during peak demand events.

(vi) existing non-network solutions, and the associated assumptions on the impact on demand levels;

Where there is an existing non-network solution in place, the impacts on demand are included in the demand forecast and the network planning process. This information includes the location, size (in MVA), season and time of day of the related demand reductions.

(vii) assumed future non-network solutions, and associated assumptions on the impact on demand levels; and

Ausgrid is proposing a new broad-based demand management program for the forthcoming regulatory period, and the impacts of this program have been included in the base demand forecast used to develop Ausgrid's Capital Plans. This program is forecast to deliver 84MVA of demand reductions across the Ausgrid network by the end of the 2014-19 period. The details of this program are outlined in Attachment 6.12 Demand Management Opex Plan to the regulatory proposal.

In addition, where it has been concluded that targeted demand management programs will be cost effective in deferring capital projects in the 2014-19 period, the equivalent reductions have been included in the demand forecast, and the relevant capital projects deferred in the Capital Works Area Plans. Specific information on these targeted demand management programs are outlined in regulatory proposal Attachment 6.12 Demand Management Opex Plan.

(viii) diversity with related substations.

Peak load is used to determine substation constraints and the diversity of related substations does not impact augmentation timing. Where transfers are proposed, it is assumed the diversity of the load transferred is similar to the destination substation when undertaking load-flow analysis of feeder networks with diversity factors included.

8.4 Provide:

(a) evidence that any independent verifier engaged has examined the reasonableness of the method, processes and assumptions in determining the forecasts and has sufficiently capable expertise in undertaking a verification of forecasts; and

Ausgrid engaged SKM-MMA between May 2012 and July 2013 as an independent verifier with sufficiently capable expertise to examine the reasonableness of Ausgrid's maximum demand forecast methodology. Whilst the review examined the Ausgrid forecast based on summer 11/12 and winter 11 actuals, the timing of the review meant that outcomes of the review, in particular recommendations for change, could be implemented for the following forecast, being the one based on summer 12/13 and winter 12 actuals which forms the basis of Ausgrid's regulatory proposal.

Ausgrid has not sought independent verification of the reasonableness of the method, processes and assumptions in relation to its customer number forecasts. Consequently, it has not provided any evidence in response to 8.4(a).

(b) all documentation, analysis and models evidencing the results of the independent verification.

The results of SKM-MMA's independent verification of Ausgrid's maximum demand forecast methodology are contained Supporting Document ID90027 SKM review of Ausgrid's peak demand forecast method.

Ausgrid has not sought independent verification of the reasonableness of the method, processes and assumptions in relation to its customer number forecasts. Consequently, it has not provided any documentation in response to 8.4(b).

9. CONNECTIONS EXPENDITURE REQUIREMENTS

9.1 Provide and describe the methodology and assumptions used to prepare the forecasts of connection works as part of the connections program, including:
(a) Estimation of connection unit costs for each customer type; and
(b) Connection volumes for each customer type.

The methodology and assumptions used to prepare forecast connection works are outlined in the following (provided as part of Ausgrid's regulatory proposal):

- Supporting Document ID68852 - Customer Number Forecast Methodology
- Supporting Document ID81882 - Customer connections capex model: Method and Outcomes (explanatory)
- Supporting Document ID32532 - Customer Number Forecasts Model
- Supporting Document ID97008 - Customer connections model: volumes
- Supporting Document ID70090 - Customer connections cost of delivery table.

9.2 Ausgrid must provide the estimation of customer contributions based upon the estimated life and revenue to be recovered from connection assets, including:
(a) the expected life of the connection;
(b) the average consumption expected by the customer over the life of the connection; and
(c) any other factors that influence the expected recovery of the distribution network use of system charge to customers.

The forecasting methodology for Capital Contributions is outlined in Supporting Document ID70090 Customer connections cost of delivery table.

10. OPERATING AND MAINTENANCE EXPENDITURE

Total forecast operating and maintenance expenditure (opex) proposal

10.1 Provide:

(a) the model(s) and the methodology Ausgrid used to develop its total forecast opex;

Ausgrid has provided the model used to develop its total forecast opex at Attachments 6.01 and 6.02 of its regulatory proposal. There are also a number of subsidiary models supporting the total forecast opex model (provided at Attachment 6.01). These subsidiary models are provided as part of the suite of supporting documents to Ausgrid's proposal.

Chapter 6.3 of the regulatory proposal contains information on the methodology.

(b) justification for Ausgrid's total forecast opex, including:

(i) why the total forecast opex is required for Ausgrid to achieve each of the objectives in clause 6.5.6(a) of the NER;

(ii) how Ausgrid's total forecast opex reasonably reflects each of the criteria in clause 6.5.6(c) of the NER; and

(iii) how Ausgrid's total forecast opex accounts for the factors in clause 6.5.6(e) of the NER;

Information for these justifications for Ausgrid's total forecast opex is contained in Chapter 6.5 of Ausgrid's regulatory proposal as well as in Attachments 5.31 to 5.33.

10.2 Provide:

(a) the quantum of non-recurrent costs for each year of the forthcoming regulatory control period; and

(b) an explanation of each non-recurrent cost;

Leaseback of HOB: In 2013, the NSW State Government mandated the sale of Ausgrid's head office building located in George St, Sydney. As part of the sale agreement, Ausgrid will be required to lease back the building for a period of two years (with an option for a third) to enable sufficient time to relocate staff and functions to other locations. This sale is expected to be finalised by 30 June 2014.

NRP & restructure implementation costs: In an effort to create an efficient operating structure over the next regulatory period, Ausgrid, in conjunction with Networks NSW, has developed a number of efficiency programs to deliver savings. These initiatives will require upfront costs for staff exits, and implementation. Additionally, post the cessation of the TSA, Ausgrid will be required to restructure operations and exit residual staff.

Maintenance – upfront costs of data capture for private mains: The first stage of the program is the identification and data capture of all current private poles and mains attached to Ausgrid's network with immediate priority in bushfire prone areas. This will occur in FY2014/15 at a one off cost of $2.8m.

NEMS – cessation of solar bonus scheme: The Solar Bonus Scheme is due to end in November 2015. On cessation, it is anticipated that 42,000 sites will require meter tariff changes to move them from the Gross to the Net scheme. This is expected to be completed between January 2016 and December 2016. This cost is equivalent to $0.5m in FY2015/16 and $0.5m in FY2016/17.

Further details of the above costs can be found in Ausgrid's forecast opex model at Attachment 6.01 (including the quantum for each year of the 2014-19 period)

10.3 if Ausgrid used a revealed cost Base year approach to develop its total forecast opex, provide:

(a) the Base year Ausgrid used; and

The base year used is FY2012/13.

(b) explanation and justification for why that Base year represents efficient and recurrent costs;

Please see Chapter 6.3 of Ausgrid's regulatory proposal.

10.4 If Ausgrid did not use a revealed cost Base year approach to develop its total forecast opex, provide:

(a) forecast expenditure by Opex Category for each year of the forthcoming regulatory control period in:

(i) Table 2.16.2 for standard control services opex; and

(ii) if Ausgrid owns any dual function assets, Table 2.16.4 for dual function assets opex;

(b) in Microsoft Excel format, clear reconciliation (including all calculations and formulae) of Ausgrid's total forecast opex to:
(i) forecast standard control services opex by driver in Table 2.16.1;
(ii) forecast standard control services opex by Opex Category in Table 2.16.2; and
(iii) if Ausgrid owns any dual function assets, Table 2.16.3 and Table 2.16.4 for dual function assets opex by Opex Category and driver, respectively;
(c) explanation of major drivers for the increases and decreases in expenditure by Opex Category in the forthcoming regulatory control period compared to actual historical expenditure;
(d) explanation and justification for:
(i) whether Ausgrid considers there is a year of historic opex that represents efficient and recurrent costs; or
(ii) why Ausgrid considers no year of historic opex represents efficient and recurrent costs.

As noted above, Ausgrid has used a revealed cost base year approach to develop its total forecast opex. Consequently, Ausgrid has not provided a response to this question.

Output growth

10.5 Provide the amount of total forecast opex attributable to output growth changes for each year of the forthcoming regulatory control period in:
(a) Table 2.16.1 for standard control services opex; and
(b) if Ausgrid owns any dual function assets, Table 2.16.3 for dual function assets opex;

Ausgrid has completed Table 2.16.1 and 2.16.3 in line with these requirements.

10.6 Provide:
(a) the output growth drivers Ausgrid used to develop the amount of total forecast opex attributable to output growth changes;

Table 14 presents the output growth factors and the corresponding output growth drivers Ausgrid used to develop the amount of total forecast opex attributable to output growth changes.

Table 14 Output growth factors and growth drivers

Output growth factor	Output growth driver
NEMS post TSA Tier 1 & 2 State (Zero Escalation)	Number of network sites Ausgrid is responsible for billing and handling B2B transactions in the NEM from approximately 700K to 1.6M.
IDO Solar Bonus & NECF Impacts (Zero Escalation)	Number of customers on Gross Solar Bonus Scheme.
ICT Business Case Costs - Cust Ops	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Business Case Costs - Data Ops	Capital program to support increasing Network System demands requiring incremental Opex.
DNMS and SCADA Program	Capital program to support increasing Network System demands requiring incremental Opex.
Mandatory Patch & Release Management	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Business Case Costs - Eng, Plan & Proj	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Efficiency Business Case Costs - ICT	Capital program to support increasing Network System demands requiring incremental Opex.

ICT Business Case Costs - ICT	Capital program to support increasing Network System demands requiring incremental Opex.

(b) any economies of scale factors applied to the growth drivers;

Table 15 provides information on economies of scale factors applied to growth drivers.

Table 15 Economies of scale factors

Output growth factor	Economies of scale factors
NEMS post TSA Tier 1 & 2 State (Zero Escalation)	The forecast has been based on incremental direct employee costs only. No factor has been included for additional overheads as it has been assumed that this activity can be absorbed within existing overhead capacity.
IDO Solar Bonus & NECF Impacts (Zero Escalation)	The forecast has been based on incremental direct employee costs only. No factor has been included for additional overheads as it has been assumed that this activity can be absorbed within existing overhead capacity.
ICT Business Case Costs - Cust Ops	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Business Case Costs - Data Ops	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
DNMS and SCADA Program	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
Mandatory Patch & Release Management	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Business Case Costs - Eng, Plan & Proj	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Efficiency Business Case Costs - ICT	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Business Case Costs - ICT	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.

(c) evidence that the growth drivers explain cost changes due to output growth; and

Table 16 provides evidence that the growth drivers explain cost changes due to output growth.

Table 16 Evidence that growth drivers explain cost changes

Output growth factor	Evidence that growth drivers explain cost changes
NEMS post TSA Tier 1 & 2 State (Zero Escalation)	The number of NEMs sites is a direct driver of the number of billing exceptions, B2B processes and NuOS activity.
IDO Solar Bonus & NECF Impacts (Zero Escalation)	On cessation, it is anticipated that 42,000 sites will require tariff changes to move them from the Gross to the Net scheme.
ICT Business Case Costs - Cust Ops	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Business Case Costs - Data Ops	Capital program to support increasing Network System demands requiring incremental Opex.
DNMS and SCADA Program	Capital program to support increasing Network System demands requiring incremental Opex.
Mandatory Patch & Release Management	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Business Case Costs - Eng, Plan & Proj	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Efficiency Business Case Costs - ICT	Capital program to support increasing Network System demands requiring incremental Opex.
ICT Business Case Costs - ICT	Capital program to support increasing Network System demands requiring incremental Opex.

(d) if Ausgrid applied any composite multiple output growth drivers:
(i) the inputs for each composite multiple output growth driver; and
(ii) the weightings for each input;

Ausgrid did not apply any composite multiple output growth drivers.

10.7 Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Ausgrid:

(a) applied the output growth drivers; and

Table 17 explains how Ausgrid has applied the output growth drivers in developing the amount of total forecast opex attributable to output growth changes.

Table 17 Application of the output growth drivers

Output growth factor	Application of the output growth drivers
NEMS post TSA Tier 1 & 2 State (Zero Escalation)	The associated direct cost forecast has been based on the current monthly exception and billing activity volumes. The resulting workload has been calculated based on extrapolating the activity of the existing site base over the post TSA site base. The respective AHT for each variable activity has been applied to the resulting volumes to derive the labour resource FTE requirement. The resulting labour resource AHT requirement has been translated into cost based on the equivalent annual cost of the relevant Ausgrid Award employee for each activity.
IDO Solar Bonus & NECF Impacts (Zero Escalation)	The associated tariff change request will require the processing of an application and subsequent NoSW. The resulting workload has been based on the historical AHT for NoSW processing multiplied by the number of forms requiring processing.
ICT Business Case Costs - Cust Ops	Incremental costs have been estimated and applied in the forecast.
ICT Business Case Costs - Data Ops	Incremental costs have been estimated and applied in the forecast.
DNMS and SCADA Program	Incremental costs have been estimated and applied in the forecast.
Mandatory Patch & Release Management	Incremental costs have been estimated and applied in the forecast.
ICT Business Case Costs - Eng, Plan & Proj	Incremental costs have been estimated and applied in the forecast.
ICT Efficiency Business Case Costs - ICT	Incremental costs have been estimated and applied in the forecast.
ICT Business Case Costs - ICT	Incremental costs have been estimated and applied in the forecast.

(b) accounted for economies of scale.

Table 18 explains how Ausgrid has accounted for economies of scale in developing the amount of total forecast opex attributable to output growth changes.

Table 18 Economies of scale and output growth factors

Output growth factor	Accounting for economies of scale
NEMS post TSA Tier 1 & 2 State (Zero Escalation)	The forecast has been based on incremental direct employee costs only. No factor has been included for additional overheads as it has been assumed that this activity can be absorbed within existing overhead capacity.
IDO Solar Bonus & NECF Impacts (Zero Escalation)	The forecast has been based on incremental direct employee costs only. No factor has been included for additional overheads as it has been assumed that this activity can be absorbed within existing overhead capacity.
ICT Business Case Costs - Cust Ops	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Business Case Costs - Data Ops	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
DNMS and SCADA Program	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
Mandatory Patch & Release Management	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Business Case Costs - Eng, Plan & Proj	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Efficiency Business Case Costs - ICT	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.
ICT Business Case Costs - ICT	Costs associated are non-labour therefore no overheads have been factored into the resulting incremental opex.

Real price changes

10.8 Provide the amount of total forecast opex attributable to changes in the price of labour and materials for each year of the forthcoming regulatory control period in:
(a) Table 2.16.1 for standard control services opex; and
(b) if Ausgrid owns any dual function assets, Table 2.16.3 for dual function assets opex;

Ausgrid has completed Table 2.16.1 and 2.16.3 in accordance with these requirements.

10.9 Provide an explanation of:
(a) how, in developing the amount of total forecast opex attributable to changes in the price of labour and materials, Ausgrid applied the real price measures in regulatory template 2.14; and

How Ausgrid has applied the real price measures in template 2.14 is described in Chapter 6.3 of the regulatory proposal and further demonstrated and described in Attachment 6.02. The application of these real price measures can be seen in the Forecast Opex Model (Attachment 6.01). In sum, Ausgrid identified the total underlying base opex by cost categories. The total base opex of each cost category is disaggregated between different cost types. The cost types represent the costs of specific inputs (internal labour, labour hire, contracted services, and materials etc) required to undertake the necessary activities to deliver standard control services and to achieve the opex objectives. For each cost category, we identify and apply the appropriate real price measure, as contained in template 2.14, to each cost type to account for the change in prices of these cost types.

(b) whether Ausgrid's labour price measure compensates for any form of labour productivity change.

Ausgrid's labour price measure does not compensate for any form of labour productivity change. Productivity change has been incorporated at a functional or activity level through the identification of specific efficiency and business process improvement initiatives.

Productivity change

10.10 Provide the amount of total forecast opex attributable to changes in productivity for each year of the forthcoming regulatory control period in:

(a) Table 2.16.1 for standard control services opex; and

(b) if Ausgrid owns any dual function assets, Table 2.16.13 for dual function assets opex;

Ausgrid has completed Table 2.16.1 and 2.16.3 in accordance with these requirements.

10.11 Provide, in percentage year on year terms, the productivity measure that Ausgrid used to develop the amount of total forecast opex attributable to changes in productivity;

Ausgrid did not utilise a specific percentage year on year productivity measure in the forecast. The productivity savings identified in table 2.16.1 represent a total cost reduction commitment by Ausgrid for the following:

- Network Reform Program efficiency savings targets as determined in conjunction with Network NSW; and
- A management commitment to offset the loss of synergy due to the cessation of the TSA and the implementation of the approved CAM.

10.12 Provide an explanation of:

(a) how, in developing the amount of total forecast opex attributable to changes in productivity, Ausgrid applied the productivity measure in 10.11;

As discussed above Ausgrid did not apply a specific measure for productivity changes in its total forecast opex. However, the total forecast opex reflects total cost reductions as outlined in 10.11.

(b) whether Ausgrid's forecast productivity changes capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice; and

No explicit cost estimation has been undertaken for new regulatory obligations, any new obligations will either be absorbed as being immaterial or addressed through positive or negative pass through.

(c) whether Ausgrid's productivity measure includes productivity change compensated for by the labour price measure used by Ausgrid to forecast the change in the price of labour.

As noted above, Ausgrid did not apply a specific productivity measure. The total forecast opex for 2014-19 however includes labour cost reductions attributable to efficiency savings targets. These savings amounts have been derived using labour price escalators to determine efficient changes in labour costs. As noted in 10.9(b), productivity change has been incorporated at a functional or activity level through the identification of specific efficiency and business process improvement initiatives.

Step changes

10.13 Provide the amount of total forecast opex attributable to opex step changes for each year of the forthcoming regulatory control period in:

(a) Table 2.16.1 for standard control services opex; and

(b) if Ausgrid owns any dual function assets, Table 2.16.3 for dual function assets opex;

Ausgrid has completed Table 2.16.1 and 2.16.3 in accordance with these requirements.

10.14 Provide an explanation of why Ausgrid considers:

(a) the efficient costs of the Step change are not provided by other components of Ausgrid's total forecast opex such as base opex, output growth changes, real price changes or productivity change;

As explained in Chapters 6.2 and 6.3 of Ausgrid's regulatory proposal, one of the drivers underlying our forecast opex for the 2014-19 period is the sale of Ausgrid's Head Office Building, in Sydney, under the direction of the NSW State Government. This sale, expected to be settled in June 2014, involves the leaseback of this building to allow for a smooth implementation and the associated leaseback cost is not included in either the base year opex, in real cost escalation or in any other change factor.

(b) the total forecast opex will not allow Ausgrid to achieve the objectives in clause 6.5.6(a) of the NER unless the Step change is included; and

As explained and demonstrated in Chapter 6.5 and in Attachment 5.31 of Ausgrid's regulatory proposal, the total proposed forecast opex for the 2014-19 period is the amount that Ausgrid considers is required to achieve each of the operating expenditure objectives. This includes the forecast costs of leasing our head office building which has been sold and expected to be settled in June 2014. Property cost is one of operation and business support required to enable Ausgrid to operate as a DNSP (i.e. staff accommodation / work space) and is therefore would be required to achieve all opex objectives (i.e. opex objectives 1 to 4).

(c) the total forecast opex will not reasonably reflect the criteria in clause 6.5.6(c) of the NER unless the Step change is included.

Similarly, in Chapter 6.5 and Attachment 5.31, we set out our consideration of how the proposed forecast opex for the 2014-19 period reasonably reflects the operating expenditure criteria and each of the opex factors. An important element of ensuring an efficient forecast opex is the prudent process employed to derive the forecast opex. A prudent forecasting process would need to take into account the anticipated circumstances and factors for the forthcoming period. As explained in Chapter 6.3 and in Attachment 5.31, we have adopted a fit for purpose approach to opex forecasting which involves the consideration of the underlying drivers of each opex cost categories; and we have done so in respect of property cost when we consider the change in our circumstances for the next period (e.g. the sale of the head office building). We note also that clause 6.5.6(c)(3) requires the forecast opex to reasonably reflect a realistic expectation of demand forecast and cost inputs. This requirement is satisfied in relation to property cost when we took into account the change in our circumstances in the 2014-19 period.

In addition, we note that the proceeds from this sale will be deducted from the RAB as well as anticipated opex savings in the later years of the 2014-19 period.

Vegetation management

10.15 Provide compliance audits of vegetation management work conducted by Ausgrid during the current regulatory control period.

A list of audit results from 1 July 2009 to 21 February 2014 is provided at Attachment I Vegetation Management Compliance Audits.

11. RISK MANAGEMENT AND INSURANCE

Risk Management Framework

11.1 Provide information that sets out Ausgrid's governance arrangements in relation to the management of risk, including:

(a) a risk appetite statement, which details the level of risk Ausgrids board is willing to accept including the nature and level of risks and the level of loss that can be sustained;

Risk is inherent in all areas of the Ausgrid business and, as such, Ausgrid is committed to achieving a positive culture of risk management based on the proactive and systematic identification and management of risk that enables effective delivery of the Corporate Plan. The risk appetite is identified in Ausgrid's Risk Matrix which is included in the Risk Management Board Policy (see Supporting Document ID00216 provided as part of Ausgrid's regulatory proposal). The risk matrix considers likelihood criteria and consequence criteria, specifically relating to: Safety, Network, Finance, Compliance, Reputation and Environment. The finance consequences in the matrix are shown in the table below.

Insignificant	Minor	Moderate	Major	Severe
<= $500K	$500K to $10M	$10M to $50M	$50M to $100M	>$100M

(b) a risk management strategy that describes Ausgrid's strategy for managing risk and the key elements of the risk management framework that give effect to this strategy; and

In 2012/13, Ausgrid, together with Endeavour and Essential Energy, implemented a revised common risk management policy and framework. The risk assessment process within the framework incorporated the use of the bow-tie methodology and a common risk matrix. This enabled Ausgrid to identify and manage risks that could affect customers, the community, environment, our people, assets and financial resources.

For the 2013/14 year Ausgrid reviewed major risks to our strategic objectives and developed and implemented action plans to help manage them.

Our management of business risk is based on three key behaviours:

- We are aware of our activities, operations and objectives.
- We consider what can go wrong and the consequences.
- We take action to prevent what can go wrong.

Also implemented were initiatives outlined in the risk management strategy to strengthen risk management practices across the company.

The Risk Management Strategic Plan and Ausgrid's Business Risks are reviewed by the Audit and Risk Committee of the Board throughout the year. 'Risk owners' provide regular reports to management and to the Audit and Risk Committee on the results of ongoing monitoring and review of risks, and on action plans to manage them. Risks which may impact on the achievement of our Corporate Plan are continually identified and assessed across nine categories, as shown in the table below.

Table 19 Outline of business risk categories

BUSINESS RISK CATEGORY	RISK DESCRIPTION
Safety	Fatality/serious injury of employee or member of public
Network	Significant customer impact related to the network
Finance	Significant unbudgeted financial loss
Compliance	Liability associated with a dispute or material breach

BUSINESS RISK CATEGORY	RISK DESCRIPTION
	of legislation or licence
Reputation	Sustained public criticism of Ausgrid
Environment	Significant environmental incident
People	Failure to deliver performance through people
Strategy	Strategic objectives are not delivered and business opportunities are lost
ICT	Significant information communications technology (ICT) &/or organisational technology service failure

Ausgrid reviewed the major risks to achieving our strategic objectives and developed and implemented action plans to help manage them. The outcomes of this work formed the Ausgrid 2013/14 Risk Management Plan, which includes the key elements of the risk management framework that give effect to these strategic objectives.

Ausgrid has provided a copy of its Risk Management Plan at Supporting Document 'ID12627-Risk management framework'.

(c) any other information that demonstrates Ausgrid's governance arrangements in relation to risks and their management.

Emerging risks, key risk indicators, the status of treatment action plans and progress against the Risk Management Strategic Plan are reported via an Executive Audit, Risk and Compliance Committee to the Board Audit Risk Committee.

Insurance (regulatory template 2.15)

11.2 General instructions:

(a) Table 2.15.1 must provide a summary of all Ausgrid's proposed insurance costs.

[redacted]

(b) Tables 2.15.2 and 2.15.3 seek more detailed information regarding total property and liability premiums only. The total property premiums forecast in table 2.15.2 must equal the sum of the premium forecasts classed as property insurance in table 2.15.1. The total liability forecast in table 2.15.3 must equal the sum of the premium forecasts classed as liability insurance in table 2.15.1.

[redacted]

(c) Amounts are exclusive of GST.

[redacted]

11.3 Provide the following information for each commercially insured risk listed in table 2.15.1:

(a) the name and description of each insured risk, including policy limits and sub-limits;

[redacted]

(b) a description of the general method used to forecast premiums (this may be in the form of an insurance premium forecast report by a qualified risk specialist); and

[redacted]

(c) any changes in insurance cover between the current and forthcoming regulatory control periods.

[redacted]

11.4 Provide the following information regarding total property and total liability insurance reported in tables 2.15.2 and 2.15.3 respectively:

(a) a description of the systematic drivers of insurance premiums;

[redacted]

(b) a description of the circumstances that have led to any premium changes over the current regulatory control period;

[redacted]

(c) a description of the method used to forecast premiums for the forthcoming regulatory control period, including estimated exposure growth and premium rate changes and any other adjustments made. Provide supporting evidence for exposure, premium rate changes, or any other proposed adjustments; and

[redacted]

(d) an explanation of how the value of insured assets is derived for property insurance (e.g. replacement costs, insured value etc.).

[redacted]

11.5 Where insurance is shared with other entities, provide:

(a) an explanation of the cost allocation approach used for each risk class;

[redacted]

[redacted]

Liability Allocation	2011/12	2012/13	2013/14	2014/15
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

(b) cost allocations (percentage) by risk class for the current regulatory control periods; and

[redacted]

(c) the cost allocation (percentage) that underlies forecast premiums for the forthcoming regulatory control period. If the proportion allocated to Ausgrid has changed, explain why.

[redacted]

11.6 Provide a report from an appropriately qualified risk specialist verifying that Ausgrid's forecast insurance premiums are efficient.

[redacted]

Self-insurance

11.7 For each risk for which Ausgrid is proposing a self-insurance allowance in the regulatory proposal:

(a) provide a description of the risk and risk exposure including cover, exclusions and limit;

[redacted]

(b) explain how each self-insurance allowance has been calculated describing the modelling and detailing key assumptions;

[redacted]

(c) provide a record of historic losses and claims against the self-insurance fund as far as records allow;

[redacted]

(d) explain why compensation should be provided for the risk. Where insurance is available from a commercial insurer and an insurance quote has been obtained, provide evidence that it is more efficient to self-insure for that risk;

[redacted]

(e) confirm that the risk for which self-insurance is being sought is not recovered through any other mechanism; and

[redacted]

(f) explain why, if a self-insurance allowance has not been sought for a particular risk in the 2009–10 to 2013–14 regulatory control period, it is being sought in the 2014–15 to 2018–19 regulatory control period.

[redacted]

11.8 If Ausgrid is proposing self-insurance for asset failure risk in the revenue proposal:

(a) provide:

- **(i)** the annual number of failures for each asset category for which self-insurance is being sought
- **(ii)** the historical costs for each asset failure
- **(iii)** a description of what those costs relate to, including any split between capex and opex.

(b) explain:

- **(i)** where the self-insurance allowance is not based on the actual historical asset failure rates and costs, how the allowance has been forecast and why it is efficient
- **(ii)** how the proposed capex has been taken into account in calculating the probability of asset failure for each asset category for which self-insurance is being sought.

[redacted]

11.9 Provide a report from an appropriately qualified actuary or risk specialist verifying the calculation of risk and corresponding self-insurance premiums.

[redacted]

12. ALTERNATIVE CONTROL SERVICES AND OTHER ACTIVITIES

12.1 The overheads relating to each alternative control service or Other Activity must be disclosed in accordance with paragraph 12.2.

Alternative Control Services: Metering Services for Meter Installation Types 5 and 6

In Chapter 4.3 of Attachment 8.15 'Type 5 and 6 metering services proposal', we outline the process used to allocate overheads to Type 5 and 6 Metering Services and the amounts allocated are shown in the attachment to the proposal titled, "Type 5 -6 Metering Pricing Model.xls", worksheet titled "Calc Overheads"

Alternative Control Services: Ancillary Network Services:

In section 3.2 of Attachment 8.22 'Ancillary network services proposal', we outline the process used to allocate overheads. The overheads allocated to each service are also shown in relevant service spreadsheets that are provided as Attachments 8.23 ('Metering related ancillary network services models') and 8.24 ('Connection related ancillary network services models').

Alternative Control Services: Public Lighting:

Attachment 8.13 ('Public lighting models') details the calculations and contributions of overheads the public lighting price lists. Attachment 8.08 ('Public lighting investment plan summary ') further details overheads associated with capital expenditure and Attachment 8.12 ('Public lighting opex forecast') further details overheads associated with operational expenditure.

12.2 Provide a list of all of the individual services that Ausgrid intends to provide to customers and levy charges for in the forthcoming regulatory control period that fit within the broader definitions of distribution services that the AER proposed to classify as alternative control services in the Framework and Approach Paper.

Alternative Control Services: Metering Services for Meter Installation Types 5 and 6

In Section 1.1 of Attachment 8.15, we list the four sub-categories of Metering Services relating to Type 5 and 6 meters that Ausgrid provides, consistent with the AER's Framework and Approach paper (March 2013).

Alternative Control Services: Ancillary Network Services:

The list of individual Ancillary Network Services is provided in the RESET RIN Templates 4.3 and 4.4.

Alternative Control Services: Public Lighting:

Attachment 8.01 details Ausgrid's public lighting objectives, actual and forecast expenditure, revenue and a general overview of Ausgrid's Public Lighting service. Attachment 8.05 further details the public lighting services Ausgrid provides to its customers and the service levels Ausgrid strives to maintain.

12.3 Provide a definition of each alternative control service listed in paragraphs 13, 14 and 15, where Ausgrid proposes a classification different to that in the Framework and Approach Paper.

This is not applicable.

12.4 For each alternative control service listed in paragraphs 13, 14 and 15, specify the charges applicable during each year of the current regulatory control period. Also include proposed charges for each year of the forthcoming regulatory control period.

Alternative Control Services: Public Lighting:

Currently, there are three categories of public lighting charges, capital, maintenance and residual charges:

- Fixed capital charge for assets installed prior to 2009;
- Annuity capital charge for assets installed post 2009;
- Maintenance charge that is applied to all assets; and
- Residual charges for assets replaced before the end of their economic life.

Attachment 8.14 details all charges associated with public lighting and Attachment 8.13 contains all models used in the calculation of this price list.

Alternative Control Services: Metering Services for Meter Installation Types 5 and 6

No separate charges are applicable for these services in the current regulatory period.

The AER defines forthcoming regulatory control period to include both the Transitional Regulatory Control period and the Subsequent Regulatory Control period. We note that no separate charges for Metering Services for Meter Installation Types 5 and 6 will apply in the Transitional year.

The charges for the Subsequent Regulatory Control Period for the different Type 5 & 6 Metering Services is shown in Sections 7.3 (up-front meter charges), 7.4 (annual meter service charges) and 7.5 (meter exit fee) of Attachment 8.15.

Alternative Control Services: Ancillary Network Services

The AER defines forthcoming regulatory control period to include both the Transitional Regulatory Control period and the Subsequent Regulatory Control period. We note that the charges for the Transitional year were set using the charges from FY14 escalated by CPI, as per the AER's preferred approach.

The charges for both the Current and Transitional Year are provided here in Table 21, Table 22 and Table 23. The charges for the Subsequent Regulatory Control Period are provided in Tables 3, 4 and 5 of Attachment 8.22 'Ancillary network services proposal'.

Table 21 Miscellaneous fees for current regulatory control period and transitional regulatory control period (1 July 2009 to 30 June 2015)

Miscellaneous Service	FY10 to FY14 price ($ exc GST)	Indicative Price FY15
Special Meter Read	$44	$45.10
Meter test	$73	$74.83
Supply of conveyancing information - desk inquiry	$37	$37.93
Supply of conveyancing information - field visit	$73	$74.83
Off-peak conversion	$59	$60.48
Disconnection visit (only) acceptable payment received	$44	$45.10
Disconnection (for non payment) at meter box	$88	$90.20
Disconnection at pole top / pillar box	$148	$151.70
Rectification of illegal connection	$221	$226.53
Reconnection outside normal business hours	$95	$97.38

Table 22 Prices for Monopoly Services for Current Regulatory Control Period (inclusive of GST)

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
Design information	Up to 5 lots $174.90 6 to 10 lots $262.90 11 - 40 lots $437.80 Over 40 lots $525.80	$88.00 per hour	$88.00 per hour	$88.00 per hour	$88.00 or $105.60 per hour
Design certification	Up to 5 lots $88.00 6 to 10 lots $174.90 11 - 40 lots $262.90 Over 40 lots $349.80	1 - 5 poles $88.00 6 -10 poles $174.90 11 or more poles $262.90	Up to 10 lots $174.90 11 - 40 lots $262.90 Over 40 lots $525.80	$105.60 per hour	$88.00 or $105.60 per hour
Design rechecking	$88.00 per hour	$88.00 per hour	$88.00 per hour	$105.60 per hour	$88.00 or $105.60 per hour
Inspection of service work (level 1 work)	Grade: A per lot / B per lot / C per lot First 10 lots: $44.00 / $105.60 / $220.00 Next 40 lots: $26.40 / $61.60 / $132.00 Remainder: $8.80 / $35.20 / $61.60	Grade: A per pole / B per pole / C per pole 1-5 poles: $52.80 / $105.60 / $193.60 6-10 poles: $44.00 / $88.00 / $174.90 11+ poles PTs: $35.20 / $61.60 / $132.00	Grade: A per lot / B per lot / C per lot First 10 lots: $44.00 / $105.60 / $220.00 Next 40 lots: $44.00 / $105.60 / $220.00 Remainder: $44.00 / $105.60 / $220.00	$88.00 or $105.60 per hour plus $44 flat fee (travel time)	$88.00 or $105.60 per hour plus $44 flat fee (travel time)

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
	plus $44 flat fee (travel time)	$306.90 $612.70 $773.30 plus $44 flat fee (travel time)	plus $44 flat fee (travel time)		
Access permit	Residential subdivisions: $29.70 per lot combined fee	$1299.10 max. per access perit	$1299.10 max. per access pemit	$1299.10 max. per access permit	$1299.10 max. per access permit
Substation commissioning		$974.60 per substation	$974.60 per substation	$974.60 per substation	$974.60 per substation
Administration	Up to 5 lots $212.30 6 - 10 lots $283.80 11 - 40 lots $354.20 Over 40 lots $425.70	Up to 5 poles: $212.30 6-10 poles: $283.80 11 or more poles $425.70	$70.40 per hour (max 6 hours)	$70.40 per hour (max 6 hours)	$70.40 per hour
Notice of arrangement	$212.30				
Re-inspection (level 1 & 2 work)	$88.00 per hour (maximum 1 hour per level 2 re-inspection) plus $44 flat fee (travel time) for level 1 re-inspections				
Re-inspection (installation	$88.00 (there is no charge for the initial installation inspection during normal working hours)				

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
work)					
Access (standby person)	$70.40 per hour				
Authorisation	$174.90				
Inspection of service work (level 2 work)	All Service connections: (NOSW = Notification of Service Work)	A Grade : $22.00 per NOSW	B Grade: $36.30 per NOSW	C Grade: $105.60 per NOSW	
Site establishment	$152.90				

Table 23 Indicative Prices for Monopoly Services for Transitional Regulatory Control Period (FY15) (exclusive of GST)

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
Design information	Up to 5 lots $162.98 6 to 10 lots $244.98 11 - 40 lots $407.95 Over 40 lots $489.95	$82 per hour	$82 per hour	$82 per hour	$82 or $98.40 per hour
Design certification	Up to 5 lots $82.00 6 to 10 lots $162.98 11 - 40 lots $244.98 Over 40 lots $325.95	1 - 5 poles $82.00 6 -10 poles $162.98 11 or more poles $244.98	Up to 10 lots $162.98 11 - 40 lots $244.98 Over 40 lots $489.95	$98.40 per hour	$82 or $98.40 per hour
Design rechecking	$82 per hour	$82 per hour	$82 per hour	$98.40 per hour	$82 or $98.40 per hour
Inspection of service work (level 1 work)	Grade: A per lot, B per lot, C per lot First 10 lots: $41.00, $98.40, $205.00 Next 40 lots: $24.60, $57.40, $123.00 Remainder: $8.20, $32.80, $57.40	Grade: A per pole, B per pole, C per pole 1-5 poles: $49.20, $98.40, $180.40 6-10 poles: $41.00, $82.00, $162.98 11+ poles PTs: $32.80, $57.40, $123.00	Grade: A per lot, B per lot, C per lot First 10 lots: $41.00, $98.40, $205.00 Next 40 lots: $41.00, $98.40, $205.00 Remainder: $41.00, $98.40, $205.00	$82.00 or $98.40 per hour plus $41 flat fee (travel time)	$82.00 or $98.40 per hour plus $41 flat fee (travel time)

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
	plus $41 flat fee (travel time)	$285.96 $570.93 $720.58 plus $41 flat fee (travel time)	plus $41 flat fee (travel time)		
Access permit	Residential subdivisions: $27.68 per lot combined fee	$1210.53 max. per access permit	$1210.53 max. per access permit	$1210.53 max. per access permit	$1210.53 max. per access permit
Substation commissioning		$908.15 per substation	$908.15 per substation	$908.15 per substation	$908.15 per substation
Administration	Up to 5 lots $197.83 6 - 10 lots $264.45 11 - 40 lots $330.05 Over 40 lots $396.68	Up to 5 poles: $197.83 6-10 poles: $264.45 11 or more poles $396.98	$65.60 per hour (max 6 hours)	$65.60 per hour (max 6 hours)	$65.60 per hour
Notice of arrangement	$197.83				
Re-inspection (level 1 & 2 work)	$82.00 per hour (maximum 1 hour per level 2 re-inspection) plus $41 flat fee (travel time) for level 1 re-inspections				
Re-inspection (installation	$82.00 (there is no charge for the initial installation inspection during normal working hours)				

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
work)					
Access (standby person)	$65.60 per hour				
Authorisation	$162.98				
Inspection of service (L2) work	All Service connections: (NOSW = Notification of Service Work)	A Grade : $20.50 per NOSW	B Grade: $33.83 per NOSW	C Grade: $98.40 per NOSW	
Site establishment	$142.48				

12.5 **For each alternative control service listed in paragraphs 13, 14 and 15, specify the total revenue earned by Ausgrid in each year of the current regulatory control period and forthcoming regulatory control period.**

Alternative Control Services: Public Lighting:

Actual and forecast public lighting revenue can be found in Attachment 8.01, in tables 2 and 6 respectively.

Alternative Control Services: Ancillary Network Services and Metering

Revenue forecast for forthcoming regulatory control period is included in Reset RIN Template 3.1.

Revenue from existing miscellaneous and monopoly services for the current regulatory control period is shown in Table 24 below.

Table 24 Revenue from existing Miscellaneous and Monopoly charges in the Current Regulatory Control Period

OPERATIONS	2012/13	2011/12	2010/11	2009/10
	Annual Actuals	Annual Actuals	Annual Actuals	Annual Actuals
Monopoly Fees				
Design Information	(642,168)	(717,862)	(781,377)	(641,061)
Administration Fees	(240,546)	(233,439)	(286,397)	(250,542)
Design Certification	(330,059)	(361,386)	(412,850)	(352,801)
Design Rechecking	(104,025)	(133,829)	(112,772)	(79,369)
Notice of Arrangement	(55,388)	(57,166)	(54,732)	(47,488)
Authorisation Fee	(239,615)	(207,766)	(218,451)	(180,392)
12Inspection (Level 1)	(1,058,714)	(1,022,656)	(784,381)	(822,517)
Monopoly Fees - Reinspection (Level 1 & 2)	(99,517)	(136,441)	(155,116)	(91,032)
Substation Commissioning	(404,889)	(334,197)	(277,005)	(286,103)
Access Permits	(1,058,941)	(826,752)	(751,321)	(640,576)
Inspection of Service Work (Level 2) (NOSW)	(1,114,493)	(1,015,758)	(1,773,310)	(872,762)
Access (Standby Person)	-	(23,092)	-	-
Site Establishment Fee	(2,575,514)	(2,313,540)	(2,584,628)	(1,932,635)
Reinspection NOEW (Electrical Contractor) (CCEW)	(194,408)	(322,238)	(180,398)	(148,075)
Off Peak Conversion	-	-	-	-
Rect of illegal conn	-	-	-	-
Total Monopoly Fees	(8,118,278)	(7,706,121)	(8,372,739)	(6,345,353)

OPERATIONS	2012/13	2011/12	2010/11	2009/10
Miscellaneous Network Charges				
ToU 1/2hrly met data	-	-	-	-
Special Meter Reading Fee	(1,889,492)	(1,201,376)	(949,793)	(820,563)
Meter Test Fee	(69,861)	(67,744)	(47,377)	(51,328)
Off Peak Conversion	(6,785)	(7,803)	(8,614)	(11,611)
Conveyancing Inquiry	-	-	-	-
Disconnection Visit	-	119	60	-
Rect of illegal conn	(5,083)	(13,481)	(10,387)	(22,938)
Supply of Conv Info Desk	-	-	-	-
Supply of Conv Inf Field	-	-	-	-
Disconnection Visit Paid	(948,904)	(688,556)	(507,144)	(1,226,518)
Discon at Meter box	(3,287,240)	(3,044,008)	(2,632,856)	(2,603,108)
Disc at Pole/Pillar Box	(9,620)	(12,580)	(5,712)	(4,674)
Re Con after Bus Hours	(137,845)	(132,925)	(107,635)	(100,105)
Total Miscellaneous Network Charges	(6,354,830)	(5,168,354)	(4,269,458)	(4,840,845)
TOTAL FEES	(14,473,108)	(12,874,475)	(12,642,197)	(11,186,198)

12.6 For metering and public lighting alternative control services, specify the number of customers in each year of the current regulatory control period, and forecasts for the forthcoming regulatory control period.

Alternative Control Services: Metering Services for Meter Installation Types 5 and 6:

The volumes (meter numbers rather than customer numbers, as this is the relevant factor for metering) is provided in template 4.2 of the Reset RIN.

Alternative Control Services: Ancillary Network Services (metering-related)

The volumes (meter numbers rather than customer numbers, as this is the relevant factor for metering) is provided in template 4.3 of the Reset RIN.

Alternative Control Services: Public Lighting:

Public lighting has 104 customers comprising of local councils and community groups. This number is assumed to remain static over the regulatory control period.

12.7 For each alternative control service listed in paragraphs 12, 13 and 14, provide the labour rate(s) used to calculate the charges for the current and forthcoming regulatory control periods

(a) Specify the labour classification level used to provide the services e.g. outsourced or internally provided and labourer type.

(b) List all direct costs, and their quantum, in the make-up of the labour rate(s)

Alternative Control Services: Metering Services for Meter Installation Types 5 and 6

Metering Services for Meter Installation Types 5 and 6 are not classified as alternative control services in the current regulatory control period.

The AER defines forthcoming regulatory control period to include both the Transitional Regulatory Control period and the Subsequent Regulatory Control period. No charges for Metering Services for Meter Installation Types 5 and 6 will apply in the Transitional year, as per the AER's preferred approach.

The labour rates used to calculate the charges for the Subsequent Regulatory Control period are included in the Attachment to the proposal titled "Forecast capex for Type 5 & 6 metering.xls" worksheet titled "Summarised" and associated links within the spreadsheet, as well as Attachment 8.15, Section 5.2.

(a) As shown in the Attachment titled "Type 5 -6 Metering Pricing Model.xls, worksheet titled "2013-14 Capital Oct YTD". *Labour Classification Level – Skilled electrical worker*

(b) As shown in the Attachment titled "Type 5 -6 Metering Pricing Model.xls, worksheet titled "Summarised" and "2013-14 Capital Oct YTD"

Alternative Control Services: Ancillary Network Services:

There is not an exact correlation between the AER's labour classification levels and the levels used to provide the services. We have developed a table that maps the services to the AER's labour classification, as a closest approximation: see Table 25,

Table 26, and

Table 27 below.

Further information is contained in Attachment 8.22 table 4 and the supporting documents to Attachment 8.23 and 8.24.

Table 25 AER definitions of *Labour Classification*

AER Labour Classification	Definition
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).
Executive manager	A manager responsible for managing multiple senior managers. NSPs typically may have one or more executive managers in areas such as CEO, HR, Finance & Treasury, Legal, Corporate and Network Operations.
Intern, junior staff, non-field work apprentice	Interns, junior staff and apprentices undertaking non field work. All apprentices undertaking or training to undertake field work should be reported under Labour Classification Level – Apprentice.
Manager	A manager responsible for managing up to full project 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).

AER Labour Classification	Definition
Senior manager	A manager responsible for managing multiple managers who each manage work teams and projects within the organisation.
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.
Support staff	Non-professional support staff not undertaking field work (e.g. clerical support, secretaries).
Unskilled labour	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 26 Mapping of services to AER Labour classifications - metering related Fee-based and quoted services

AER Service Group	Services	Mapping to AER Labour classification
Site establishing fee services	Site establishment	Internally provided *Support Staff*
Ancillary Metering Services	a - Special Meter Reading	Outsourced & Internally provided *Unskilled labour*
	b - Meter Test	Internally provided *Skilled electrical worker*
	c - Franchise (CT) Meter Install	Internally provided *Skilled electrical worker*
	d - Replace/Remove T5/6 Meter	Internally provided *Skilled electrical worker*
	e - Type 5-7 non-standard Meter Data Services	Internally provided *Support Staff*
	f - Emergency Maintenance of Failed Metering Equipment not owned by DNSP	Internally provided *Skilled electrical worker*

AER Service Group	Services	Mapping to AER Labour classification
Off Peak conversion	Off Peak conversion	Internally provided *Skilled electrical worker*
Reconnections/ Disconnections	a - Disconnection - Site Visit	Internally provided *Skilled electrical worker*
	b - Disconnection/Reconnection - Disconnection Completed	Internally provided *Skilled electrical worker*
	c - Disconnection/Reconnection - Technical Disconnect	Internally provided *Skilled electrical worker*
	d - Disconnection/Reconnection - Pillar/Pole - Disconnection Complete	Internally provided *Skilled electrical worker*
	e - Disconnection/Reconnection - Pillar/Pole - Site Visit	Internally provided *Skilled electrical worker*
	f - Reconnection outside of business hours	Internally provided *Skilled electrical worker*
Network Tariff change request	Network tariff change request	Internally provided *Support Staff*
Move in move out meter reads	Move in, Move out meter reads	Outsourced & Internally provided *Unskilled labour*
Recovery of debt collection costs dishonoured transactions	Recovery of debt collection costs - dishonoured transactions	Internally provided *Support Staff*
Services provided in relation to a Retailer of Last Resort (ROLR) event	Services provided in relation to a Retailer of Last Resort (RoLR) event	Internally provided *Support Staff*
Attendance at customers' premises to perform a statutory right where access is prevented.	Attendance to perform a statutory right where access is prevented	Internally provided *Skilled electrical worker*

AER Service Group	Services	Mapping to AER Labour classification
Vacant Property reconnect/disconnect	a - Vacant property reconnect/disconnect	Internally provided *Skilled electrical worker*
	b - Vacant property reconnect/disconnect. (site visit only)	Internally provided *Skilled electrical worker*

Table 27 Mapping of services to AER Labour classifications - connection related Fee-based and quoted services

AER Service Group	Service	Mapping to AER Labour Classification
Design related services	Design information	Internally provided *Professional, Semi-professional, Manager*
	Design certification	
	Design rechecking	
ASP inspection services	Inspection of service work by Level 1 ASPs	Internally provided *Professional, Semi-professional, Skilled electrical, Manager*
	Inspection of service work (by Level 2 ASPs)	*Semi-professional*
	Re-inspection of L1 & L2	Internally provided *Professional, Semi-professional, Manager*
Reinspection of installation work in relation to customer assets	Re-inspection	Internally provided *Semi-professional*
Contestable Substation Commissioning		Internally provided *Semi-professional, Professional, Skilled electrical*
Access Permits		Internally provided *Semi-professional, Skilled electrical*
Clearance to work		Internally provided *Semi-professional*
Access (standby person)		Internally provided *Semi-professional*
Notices of arrangement	Level 1 ASP	Internally provided *Support staff*
Authorisation of ASPs	Level 1 ASP	Internally provided *Support staff, Semi-*

AER Service Group	Service	Mapping to AER Labour Classification
		professional, Manager
	Level 2 ASP	Internally provided *Support staff, Semi-professional*
Administration services relating to work performed by ASPs including processing work		Internally provided *Support staff*
Supply of conveyancing information	Desk enquiry	Internally provided *Support staff*
	Field Visit	Internally provided *Support staff, Professional*
Customer interface coordination for contestable works		Internally provided *Professional, Manager*
Preliminary enquiry service		Internally provided *Professional, Manager*
Connection offer service (basic or standard)		Internally provided *Support Staff, Professional, Manager*
Rectification works	a. Rectification of illegal connections	Internally provided *Skilled electrical*
	b. Provision of service crew/additional crew	Internally provided *Skilled electrical*
	c. Fitting of Tiger tails	Internally provided *Skilled electrical*
	d. High load escorts	Internally provided *Semi professional, Skilled electrical*
Connection / relocation process facilitation		Internally provided *Professional, Manager*
Services to supply and connect temporary supply to one or more customers		Internally provided *Semi professional, Skilled electrical*
Carrying out planning studies and analysis relation to distribution (including sub-transmission and dual-function assets) connection applications		Internally provided *Manager*
Services involved in obtaining deeds of agreement in relation to property rights associated with contestable connection works		Outsourced (*professional*) and internally provided *Support Staff, Semi professional, professional, manager*

AER Service Group	Service	Mapping to AER Labour Classification
Investigate, review & implementation of remedial actions associated with ASP's connection works		Internally provided *Manager*

Alternative Control Services: Public Lighting:

Public lighting labour rates can be found in Attachment 8.12. The breakup of costs of labour performed by Ausgrid staff versus external service providers can be found in the public lighting pricing models at Attachment 8.13.

Supporting documentation within Attachment 8.12 '2014.04.29 Public Lighting Opex - Consolidated Supporting Figures v1.xlsx' details the calculations of labour rates, on-costs and overheads associated with public lighting pricing.

12.8 List each material category (e.g. meters, poles, brackets) required for the provision of alternative control services listed in the response to paragraphs 12, 13 and 14.

(a) Provide a description of each material category

(b) Provide the average unit costs for each material category

(c) List all direct costs included in the unit costs

(d) Specify the calculation of the quantum of direct materials costs included in the unit cost of materials.

Alternative Control Services: Metering Services for Meter Installation Types 5 and 6

Section 14 of this response covers all of these requirements and we provide a response to these requirements there.

Alternative Control Services: Ancillary Network Services:

Two Ancillary Network services have a material component and the detail is included in the relevant service spreadsheets that are provided in Attachments 8.22 and 8.23 Filenames: Rectification_works.xls and Temp_Power.xls

Alternative Control Services: Public Lighting:

Attachment 8.02 Introduction to Ausgrid's Public Lighting Business, details all components that make up Ausgrid's street lighting network.

The average unit costs for each component can be found in Table 4.1.3 of the reset RIN template.

Attachment 8.13 - Public Lighting models includes the build up of all component pricing and costs.

Supporting documentation to Attachment 8.13 - '2014.04.29 Public Lighting Opex - Consolidated Supporting Figures v1.xlsx' details the inputs, including materials pricing, to the public lighting price lists.

13. FEE BASED AND QUOTED ALTERNATIVE CONTROL SERVICES

13.1 Provide a description of each fee based and quoted service, explaining the purpose of the service and list the activities which comprise each service. The list of fee based and quoted services should be consistent with those services listed in Ausgrid's annual tariff proposals.

(a) Specify if the charges are for fee based and/or quoted alternative control services;

(b) Explain the reasons for the different charge with reference to the costs incurred;

(c) Explain the method used to set the different charge; and

(d) Provide the calculations underpinning the different charge.

Alternative Control Services: Ancillary Network Services:

The description of each fee based and quoted service is included in the Basis of Preparation. Section (a), (b), (c) and (d) are included in the relevant service spreadsheets that are provided in Attachments 8.23 and 8.24 of Ausgrid's regulatory proposal.

13.2 Identify the tasks involved in providing the service in regulatory templates 4.3 and 4.4

(a) Map the class of labour required to provide the service listed in regulatory templates 4.3 and 4.4.

(b) The number of workers required to undertake the task and deliver the service

(c) The average time required to complete the task and deliver the service

Alternative Control Services: Ancillary Network Services:

The tasks in providing the services are outlined in the service spreadsheets. (a), (b), (c) and (d) are included in the relevant service spreadsheets that are provided as Attachments 8.23 and 8.24.

13.3 If materials are required to provide the service, specify each material category

Alternative Control Services: Ancillary Network Services:

Two Ancillary Network services have a material component and the detail is included in the relevant service spreadsheets that are provided as Attachments 8.23 and 8.24, filenames: Rectification_works.xls and Temp_Power.xls

13.4 Provide all current and proposed charges for each fee based and quoted alternative control service in the current and forthcoming regulatory control periods.

Alternative Control Services: Ancillary Network Services:

The AER defines forthcoming regulatory control period to include both the Transitional Regulatory Control period and the Subsequent Regulatory Control period. We note that the charges for the Transitional year were set using the charges from FY14 escalated by CPI, as per the AER's preferred approach.

The charges for both the Current and Transitional Year are provided in 12.4 above. The charges for the Subsequent Regulatory Control Period are provided in Tables 3, 4 and 5 of Attachment 8.22.

14. METERING ALTERNATIVE CONTROL SERVICES

14.1 For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the:

Ausgrid RIN includes all network metering costs, excluding ancillary metering services.

(a) Direct materials and direct labour costs;

Labour and associated incidental materials are detailed in Table 4.2.2 cost section.

(b) Installation costs;

For new and upgraded metering in NSW, customers pay ASP directly for installation costs.

(c) Meter purchase costs;

Meter hardware costs are detailed in Table 4.2.2 cost section rows 11 and 12 with columns depicting years.

(d) Volumes of work;

Work volumes for Type 5 and 6 metering are detailed in Table 4.2.2 Volumes section with columns depicting years.

(e) Other costs associated with providing metering services;

Metering costs not attributed to specific metering costs i.e. data validation.

(f) Type of meters installed and forecast to be installed, separately for new meters and for replacement meters;

Volumes of meters installed and projected to be installed by type relating to new meter installation, and meter replacement detailed in Table 4.2.2 Volume section rows 26/27 and 29/30 respectively – with columns depicting years.

(g) The volume of meters by type set out in (f) and the revenue earned and forecast to be earned by each meter type; and

Volume of meters by type as per (f). No revenue specifically recovered for metering services in the current regulatory control period, it is recovered as part of NUoS. The basis of revenue is the forecast costs in columns X to AB.

(h) The total operating and maintenance costs incurred, and forecast to be incurred, for metering services.

Total operating and maintenance costs are detailed in Table 4.2.2 cost section all rows except 1-12 and 25-30 with columns depicting years.

14.2 For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of:
(a) The type of work undertaken (e.g. meter reconfiguration, special meter read) including a description of the activities undertaken to provide the service;

Metering works is not a defined term. The services provided as an example are currently miscellaneous services and will form part of Ancillary Network Services from 1 July 2015. The descriptions of these services have been covered in the response to 13.1.

If the AER intended to cover Type 5 and 6 Metering Services, refer to response in 12.2.

(b) The labour costs involved in providing the service, including any overheads;

Labour costs for metering services excluding Ancillary Network Services are covered in 14.1.

(c) Any materials costs involved in providing the service;

There are no material costs for metering-related Ancillary Network Services.

Material costs (meters) are covered in 14.1 (c).

(d) The number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;

Volumes for metering-related Ancillary Network Services are provided in Template 4.3 of the Reset RIN.

Volumes for Type 5 and 6 Metering Services are provided in Template 4.2.2.

(e) The charge per service; and

Charges for metering-related Ancillary Network Services are provided in 12.4 and in Table 1.

There are no separate charges for Type 5 and 6 Metering Services in the Current Regulatory Control period.

(f) The revenue earned by each service.

Revenue for metering-related Ancillary Network Services is covered in 12.5.

There is no specific historical revenue in Type 5 and 6 metering services.

The forecast Type 5 and 6 metering costs will form the basis of alternative control metering revenue.

15. PUBLIC LIGHTING ALTERNATIVE CONTROL SERVICES

15.1 Specify which items are capital expenditure and operational expenditure for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period.

This information has been provided in Ausgrid's regulatory proposal for the forthcoming regulatory control period. Please see Attachment 8.01 – Public Lighting Overview – Section 8.3.

15.2 Provide unit costs for the current regulatory control period and forecast for the forthcoming regulatory control period for:

- **(a) Luminaires;**
- **(b) Dedicated street lighting poles;**
- **(c) Brackets;**
- **(d) Lamps;**
- **(e) Photoelectric cells;**
- **(f) Labour rate (per hour);**
- **(g) Miscellaneous materials.**

This information has been provided in Ausgrid's regulatory proposal. Please see Attachment 8.01 – Public Lighting Overview – Section 5.

Note, the Post 2009 'Annuity' Capital Charge Model is confidential.

15.3 Provide the depreciation period in years for each type of luminaire.

This information has been provided in Ausgrid's regulatory proposal. Please see Attachment 8.01 – Public Lighting Overview – Section 5.

Ausgrid uses an annuity model to price luminaires and therefore there is no depreciation period associated. Luminaires are assumed to have a life of 20 years and this is the basis of the pricing of the annuity model.

15.4 Provide the bulk change cycle in years for lamps and photoelectric cells.

This information has been provided in Ausgrid's regulatory proposal. Please see Attachment 8.01 – Public Lighting Overview – Section 3.

15.5 Provide details of the average replacement age of each type of luminaire.

Ausgrid has provided this information in Table 5.2.1 of the regulatory templates.

15.6 Provide the number of luminaires, by type.

Ausgrid has provided this information in Table 4.1.1 of the regulatory templates.

15.7 Provide the number of luminaires, poles and brackets replaced per year, for the current and forthcoming regulatory control periods.

Ausgrid has provided this information in Table 2.2.1 of the regulatory templates.

15.8 Provide details, including assumptions used, for any other costs that are incurred for the provision of public lighting services.

This information has been provided in Ausgrid's regulatory proposal. Please see Attachment 8.01 – Public Lighting Overview – Sections 3 & 5, and Attachments 8.12 and 8.13 - Operational expenditure and associated cost build up model.

15.9 Provide models and/or modelling that underpins proposed charges for the forthcoming regulatory control period and the reasons for the assumptions behind those forecasts.

This information has been provided in Ausgrid's regulatory proposal. Please see Attachment 8.01 Public Lighting Overview Section 5, and the following public lighting models in Attachment 8.13:

- Pre 2009 'Fixed' Charge Model (Confidential)
- Post 2009 'Annuity' Capital Charge Model (Confidential)
- Opex Model (Confidential).

16. ECONOMIC BENCHMARKING

16.1 Complete the Economic Benchmarking regulatory templates (3.1 to 3.7) in accordance with:

(a) The instructions and definitions for variables within: Economic benchmarking RIN For distribution network service providers Instructions and Definitions Ausgrid (ABN (ABN 67 505 337 385)) November 2013

(b) and the instructions in paragraphs 16.1 to 16.4.

The Economic Benchmarking regulatory templates in the Reset RIN have been completed in accordance with these requirements.

16.2 The instructions in paragraphs 16.2(a) to 16.2(f) take precedence over those in Economic benchmarking RIN For distribution network service providers Instructions and Definitions Ausgrid (ABN (ABN 67 505 337 385)) November 2013.

(a) The forecast revenue groupings in tables 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous regulatory years. However:

(i) Total revenues must equal total forecast revenues as proposed by Ausgrid in its revenue proposal, and

(ii) Revenue groupings must reflect Ausgrid's forecast demand for its services in the Forthcoming Regulatory Control Period in its revenue proposal.

Total revenues included in Tables 3.1.1 and 3.1.2 equal total forecast revenues as proposed by Ausgrid in its revenue proposal, noting that revenues in Ausgrid's revenue proposal are presented in nominal dollars whereas Tables 3.1.1 and 3.1.2 requires revenues in real dollars.

The forecast revenues in the groupings requested in Tables 3.1.1 and 3.1.2 reflect Ausgrid's forecast in relation to the relevant services, noting that different forecasts are applicable to standard control services and alternative control services and that forecast revenues for alternative control services are shown as alternative control services in year 14/15.

In addition, revenue from other sources in Table 3.1.1 comprises forecast revenue from transmission standard control services. While revenue from other customers in Table 3.1.2 comprises revenue from Ausgrid's transmission standard control services only.

(b) The definition of a tree must be applied when completing the variables "Average number of trees per urban and CBD vegetation maintenance span" (DOEF0208) and "Average number of trees per rural vegetation maintenance span" (DOEF0209)

Information in the RIN has been provided in this manner and explained in the Basis of Preparation.

Ausgrid utilised LiDAR acquired data for 2012 and 2013 to calculate vegetation within the vicinity of its network covered by vegetation management activities. The spread or coverage of the LiDAR data and tree identification was up to 8 meters from the network. Trees and vegetation outside of this corridor were ignored and deemed not to be within the vicinity of the network for vegetation management activities.

(c) In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Ausgrid is not responsible for the vegetation management associated with the span are not to be counted.

Ausgrid has provided information for these variables in the regulatory templates in a manner consistent with this requirement.

The total vegetation maintenance spans is an average of the 2011-2013 for vegetation maintenance spans / the total number of spans percentage applied to the forecast results for total number of spans. The feeder category split is based on the percentage of each classification to total vegetation maintenance spans for the 2013 results (most accurate data). This percentage is applied to the projected total vegetation maintenance spans"

(d) "Total number of spans" (DOEF0205) does not include service line spans.

Services have been included and explained in the Basis of Preparation.

Services line lengths are an arbitrary length of 10 metres towards the centre of the supplied land parcel; therefore they have been excluded when calculating the lengths.

In areas where the service span connected to Ausgrid's network is subject to vegetation management practises it has been counted as a span, it has also been counted as a span when calculating the total number of spans.

This is because the span connected to our network where it is connected to the POA, or as defined in the NSW Service Installation Rules is considered part of Ausgrid's network. In some regions these spans are subject to vegetation management practises and by removing them may result in the "Total Vegetation Management Spans" (DOEF0204) to be greater than "Total Number of Spans" (DOEF0205).

(e) Ausgrid must report the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length (this is the total feeder route line length for all CBD, urban, short rural and long rural feeders) against "Rural proportion" (DOEF0201).

Ausgrid has provided information for these variables in the regulatory templates in a manner consistent with this requirement.

(f) For the purposes of calculating the "Route line length" variable (DOEF0301) or other variables measured in terms of route line length:
(i) The length of service lines are not to be counted
(ii) the length of a span that shares multiple voltage levels is only to be counted once
(iii) the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately

Ausgrid has provided information for these variables in the regulatory templates in a manner consistent with this requirement.

16.3 All forecast variables in the Economic Benchmarking regulatory templates must align with those in Ausgrid's regulatory proposal. For the avoidance of doubt this includes forecast:
(a) opex and capex;

All forecast variables contained in the Ausgrid's completed regulatory template 3.2 "Opex" aligns with those in Ausgrid's regulatory proposal.

Ausgrid notes there is no forecast capex information required in the Economic Benchmarking regulatory templates of the Reset RIN.

(b) Maximum demand, customer numbers, Energy delivery;

All forecast maximum demand variables contained in the Ausgrid's completed regulatory templates 3.4, 5.3 & 5.4 align with those in Ausgrid's regulatory proposal.

Forecast customer numbers, forecast energy and revenues align with those presented in Ausgrid's regulatory proposal. The customer number forecast presented in Table 3.4.2 is consistent with the supporting document to the regulatory proposal, 'ID68852 Customer Number Forecast Methodology'.

Energy Delivered in Table 3.4.1 is based on Attachment 4.11 to the regulatory proposal *Energy Forecasts to 2018/19 December 2014.*

(c) Revenues;

Forecast revenues in Table 3.1.1 and 3.1.2 reconcile to the revenues in Ausgrid's PTRM for standard control services and regulatory proposal for both standard control services and alternative control services. Noting that revenues for metering services Type 5-6 and metering related ancillary network services are not bundled with standard control services for FY15 but are included as alternative control services for all years 2014-19.

See also the answer in relation to 16.2(a) above with respect to revenue from other sources in Table 3.1.3 and revenue from other customers in Table 3.1.2.

(d) quality of services variables including SAIDI , SAIFI and MAIFI; and

All forecast variables contained in the Ausgrid's completed regulatory template 3.6 "Quality of Service" aligns with those in Ausgrid's regulatory proposal. All SAIDI, SAIFI and MAIFI variables contained in regulatory template 6.2 "Reliability and Customer Service Performance" also aligns with those in Ausgrid's regulatory proposal.

(e) Quantities of physical assets

In the absence of specifically retained forecast values for quantities of physical assets, historical levels and trending data was used in conjunction with known forecast works that have been included in the regulatory submission, to produce an overall forecast that is harmonious to the information contained within Ausgrid's regulatory proposal. However future direction changes and an incongruent regulatory determination would affect the accuracy of these predictions.

16.4 RAB asset financial data in the Assets (RAB) regulatory template must reconcile to that in Ausgrid's PTRM and RFM.

RAB asset financial data presented in Templates 3.3 Assets reconciles to Ausgrid's PTRM and RFM.

17. PROVISIONS

17.1 For each of Ausgrid's provisions, provide the information required in regulatory template 2.13 in accordance with:

(a) regulatory template 2.13; and

(b) Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.

Ausgrid has provided the information required in Regulatory template 2.13 in the Microsoft Excel Workbooks attached at Appendix A of the Regulatory Information Notice (RIN) issued to Ausgrid on 7 March 2014, and amended to include the relevant Microsoft Excel Workbooks on 21 March 2014.

Information reported in Table 2.13.1 is consistent with the requirements in paragraph 17.1 of Schedule 1 of the RIN. The information reported is in accordance with the Regulatory Accounting statements as well as Ausgrid's Cost Allocation Methodology and the instructions Worksheet 2.13.

Ausgrid has provided the information in regulatory template 2.13 in accordance with the Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.

Ausgrid prepares Standard Control Services Annual Regulatory Statements for AER which comply with Australian Accounting Standards and the Regulatory Information Requirements Guidelines for the NSW Electricity Distributors. These are independently audited and reviewed each year before reporting separately to the AER. The Regulatory Accounting Statements include Standard Control Services (Distribution) and Standard Control Services (Transmission) and Alternative Control Services (public lighting).

17.2 If, in a given year, there is an increase in the amount of a provision, provide reasons for this increase, including:

(a) the expected timing of any resulting outflows of economic benefits;

(b) an explanation of the uncertainties about the amounts or timing of the outflows;

(c) supporting consultant's advice, including actuarial reports; and

(d) if there is no supporting consultant's advice, the process and assumptions Ausgrid used in determining the increase in the provision.

Employee Benefits

Significant fluctuations in employee benefits mainly reflect the movements based on actuarial assessments and calculations as a result of changes in long government bond rates. In Table 2.13.1, the increases in the provisions in FY2007/08, FY2009/10 and FY2011/12 mainly relate to the decreasing long term government bond rate and this also affects the "increase during the period in the discounted amount arising from the time and discount rate" and "unused amounts". The timing of the outflows is dependent upon when employees take leave or leave the organisation. The actuary prepares this information based on historic trends.

The amounts are supported by actuarial reports which have then been rolled forward to 30 June. Copies of the actuary reports are provided at Attachment M Employee Benefits Actuary Reports. The discount rate amounts have been estimated (as stated below) as this was not provided by the actuaries.

Restructuring Costs

The movement in FY2013 represents cost related to recent restructuring in Ausgrid. This was disclosed separately for the first time in FY2013. In previous years, this was disclosed in the Other Provision category. FY2014 restructuring cost movement has not been forecasted as information is currently not available.

Ausgrid is undergoing a significant reorganisation as it moves towards a lower cost operating model. The expected timing of outflows is for 2013-2015. The amounts also include estimates of the "Mix and Match program". This program allows eligible employees to leave through an Early Retirement Scheme and create vacancies for other staff, whose roles will be redundant.

Insurance

Significant increase in FY2012 relate to workers' compensation adjustments based on actuarial calculations. The movement in FY2013 in Table 3.1.2 and movement in 'unused amounts' in Table 3.1.1 reflect the adjustment to the workers compensation related to the changes in the legislation and hence change in measurement for the year end actuarial calculation.

Other

Significant movement is noted in FY2010 due to increase in provision mainly relating to site remediation. A new provision was recognised for contaminated land restoration and an increase in asbestos work. It is expected that these provisions will be utilised across the next 4 years (FY2011-2015). FY2012 increases in the provision related to an update in the assumptions and impact of the discount rate for the provision related to the removal of Polychlorinated Biphenyls (PCB) oil which is required by legislation, a further recognition of decommissioning costs and restructuring costs.

17.3 Provide the allocation of the movement in total provisions in regulatory template 2.13, Table 2.13.2 to:

(a) opex;

Ausgrid has provided the information required in Regulatory template 2.13 in the Microsoft Excel Workbooks attached at Appendix A of the Regulatory Information Notice (RIN) issued to Ausgrid on 7 March 2014, and amended to include the relevant Microsoft Excel Workbooks on 21 March 2014. Further information is below and stated in the Basis of Preparation.

(b) as-incurred capex by roll forward model asset class; and

Ausgrid has not shown 'movement in provisions allocated to as-incurred capex by asset class' (Table 2.13.2) as the net impact of the provision movement is fully utilised, i.e. increases in capex are fully utilised during the year.

(c) other, where the movement in the provision is neither capex nor opex.

Employee benefits

The provision movement reflects the impact of the defined benefits superannuation which is posted to equity accounts. This follows the accounting standard treatment. This accounting standard change commenced in FY2009.

Dividend

Provision for dividend is 70% of Ausgrid's Net Profit After Tax subject to guidelines provided by the Treasury and in line with Ausgrid's Cost Allocation Methodology.

Other

Provision for PCB disposal and decommissioning movements reflect the increase in the discount impact which is reflected in interest expense as well as the impact to asset values (not capex). This is in line with the accounting standards.

17.4 Identify and explain any assumptions applied for the allocation of asset class provided under paragraphs 17.3(b).

Financial information on provisions reconciles to the reported closing balances for provisions in the Regulatory Accounting Statements for each Regulatory Year. Ausgrid has deviated from the Regulatory Accounting Statements, where more information has been obtained to meet the required categories in the Reset RIN. Where deviations have occurred, the information has been extracted from the accounting system. Movements in the provision accounts reflect the movements in the accounting system.

The disclosure of the discount rate may have impacted the values reported in the Regulatory Accounting Statements for each Regulatory Year in the categories of "increases to the provision" or "unused amount reversed during the period". The discount rate impact was estimated and was not sourced from the accounting system.

The discount rate assumptions applied to the provisions are outlined below

Defined Benefits Superannuation (in Employee Benefits Provisions)

The defined benefits superannuation position has been assessed by an actuary each year. The impact and value of this assessment is recognised by Ausgrid. The actuary did not provide Ausgrid any information on the impact of discount rates unless specifically requested. The discount rate impact is known for the years ended 30 June 2012 and 2013. For FY2008 to FY2011, the discount rate impact is not known. The "increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate" for FY2008 to FY2009 has been estimated by Ausgrid as the year-end adjustment. The discount rate for FY2010 and FY2011 has been estimated by Ausgrid as the net impact of actuarial gains and losses as the "discounted rate impact". The discount rate for FY2014 was not able to be estimated. The expected timing of any resulting outflows is in line with the actuarial assessments obtained.

Long Service Leave, Supplementary Superannuation and Severance allowance, and Preserved Sick leave (in Employee Benefits Provisions)

The position of these provisions has been assessed by an actuary each year. The impact and value of this assessment is recognised by Ausgrid. The actuary only provided information as at 31 December of each financial year. Therefore Ausgrid has rolled forward this discount rate impact to calculate an estimated 30 June discount rate effect. The discount rate for FY2014 was not able to be estimated. The expected timing of any resulting outflows is in line with the actuarial assessments obtained.

Workers' Compensation Insurance

The position of this provision has been assessed by an actuary each year. The impact and value of this assessment is recognised by Ausgrid. The actuary did not provide any information on the impact of discount rates. The "increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate" for FY2008 to FY2013 has been estimated by Ausgrid using the actuarial numbers of "effect of change in economic assumptions" over the "sum of changes across the period". This actuarial information used by the actuary is based on data extraction dates which are not exact balance sheet dates. The discount rate for FY2014 was not able to be estimated. The expected timings of any resulting outflows are in line with the actuarial assessments obtained.

PCB and Site Remediation provisions (in Other Provisions)

The discount rate applied to the PCB and the Site Remediation provisions was based on market yield on Commonwealth government 10 year bond rate as at 30 June for the relevant year.

18. FORECAST PRICE CHANGES

18.1 Provide, in regulatory template 2.14, the labour and material price changes assumed by Ausgrid in estimating Ausgrid's forecast capex proposal and the forecast opex proposal. All price changes must be expressed in percentage year on year real terms.

This information has been provided in the RIN as required. Data provided in RIN Template 2.14.1 contains historic & forecast labour & material price changes.

18.2 Provide:

(a) the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;

Supporting information provided as part of the regulatory proposal are the models used to derive the historic & forecast price changes developed by CEG, including:

- Attachment 5.16 - Overview of the cost escalation methodology
- Attachment 5.17 - Cost escalation inputs and model
- Attachment 5.18 - Independent Economics - Labour escalation for NSW DNSPs
- Attachment 5.19 - CEG Material escalation for NSW DNSPs

(b) in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and

Ausgrid has provided a copy of the current Enterprise Bargaining Agreement at Attachment N Current Enterprise Bargaining Agreement.

(c) evidence that the forecast price changes accurately explain the change in the price of goods and services purchased by Ausgrid, including evidence that any materials price forecasting method explains the price of materials previously purchased by Ausgrid.

Evidence that forecast price changes accurately explain changes in prices of goods & services is contained in major contract information that have been in confidential Attachment F. These contracts include price adjustment mechanisms which have be reflected in Ausgrid's cost escalation model which translates forecast increases in commodity prices into cost indexes for major material costs.

18.3 In Ausgrid's Basis of Preparation, explain:

(a) the methodology underlying the calculation of each price change, including:

(i) sources;

(ii) data conversions;

(iii) the operation of any model(s) provided under paragraph 18.2(a); and

(iv) the use of any assumptions such as lags or productivity gains;

The methodology used for forecasting labour, contracted services and materials is outlined in the methodology documents provided in Attachment 5.16 to Ausgrid's regulatory proposal. This includes data sources, data conversion and use of the model. No productivity adjustments were made to forecast labour and materials cost forecasts.

(b) whether the same price changes have been used in developing both the Forecast capex Proposal and forecast opex proposal; and

The same prices changes have been applied to both capex & opex proposals.

(c) if the response to paragraph 18.3 is negative, why it is appropriate for different expenditure escalators to apply.

Not applicable.

18.4 If an agreement provided in response to paragraph 18.2(b) is due to expire during the Forthcoming regulatory control period, explain the progress and outcomes of any negotiations to date to review and replace the current agreement.

The current agreement is due to expire in December. Negotiations have commenced but at early stages and the expected outcome of these negotiations is unknown at this stage.

19. RELATED PARTY TRANSACTIONS

19.1 Identify and describe all other entities which:

(a) are a related party to Ausgrid and contribute to the provision of distribution services; or

Ausgrid Pty Limited ACN 060 979 688 is a wholly owned subsidiary of Ausgrid. Under arrangements described in 19.3, Ausgrid Pty Limited is the body that provides the head office accommodation including accommodation for a control room and is therefore considered to be a body that contributes to the provision of distribution services by Ausgrid.

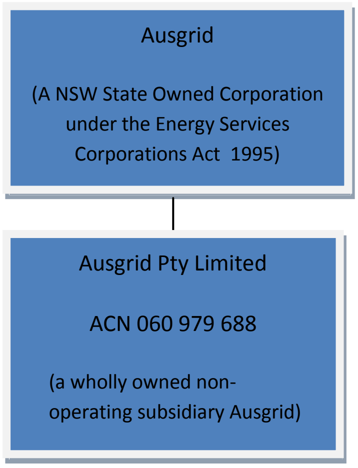
(b) have the capacity to determine the outcome of decisions about Ausgrid's financial and operating policies.

Nil.

19.2 Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 19.1.

Figure 2 depicts the relationships between the entities identified in 19.1(a).

Figure 2 Organisational structure of Ausgrid's related party entities



19.3 Identify:

(a) all arrangements or contracts between Ausgrid and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services; and

Ausgrid is the registered proprietor of 570 George Street, Sydney (the **Ausgrid Building**). The Ausgrid Building is currently occupied by Ausgrid. The Ausgrid Building is Ausgrid's head office accommodation and includes accommodation for a control room.

The contracts that relate to the provision of distribution services by Ausgrid include a lease agreement (the Ausgrid Lease) and a Licence Agreement. Both contracts are between Ausgrid and Ausgrid Pty Limited. Further details are provided in 19.3 (b).

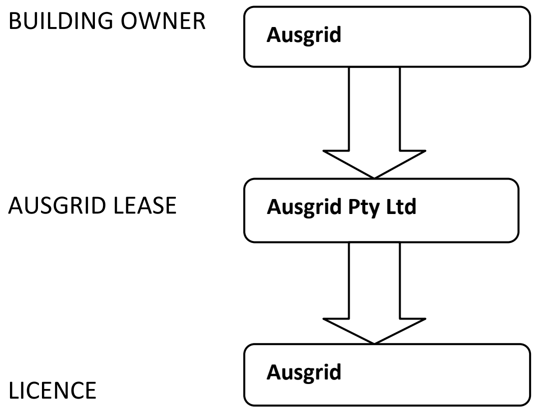
(b) the service or services the subject of each arrangement or contract.

Ausgrid has granted to Ausgrid Pty Ltd a lease of the whole of the Ausgrid Building excluding certain premises subject to existing leases. The Ausgrid Lease is for a term commencing on 7 March 2014 and expiring on 30 June 2016 with one option to renew for a period of one year expiring on 30 June 2017.

Although Ausgrid has granted the Ausgrid Lease to Ausgrid Pty Ltd, Ausgrid still needs a right to use and occupy and operate its business from the Ausgrid Building. By a licence, Ausgrid Pty Ltd has granted the right to Ausgrid as licensee to use and occupy and operate its business from the Ausgrid Building. The licence agreement was entered into on 29 May 2014 and will have a term concurrent with the lease between Ausgrid and Ausgrid Pty Ltd. Copies of the lease and licence agreement are attached at Attachment O Supporting Documents for Related Party Services.

Figure 3 depicts the provision of these services.

Figure 3 Provision of related party services



19.4 For each service identified in the response to paragraph 19.1:

(a) provide:

(i) a description of the process used to procure the service; and

(ii) supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ausgrid and the relevant provider;

The NSW Government through two shareholding Ministers is the owner of Ausgrid.

The Ausgrid Building was identified for sale as part of Tranche 2 of the NSW Government's asset divestment process.

The process for the sale of the Ausgrid building as going concern was devised and managed by advisers and consultants engaged as part of the broader NSW Government divestment process.

On 6 March 2014, Ausgrid entered into a sale contract for the sale of the Ausgrid Building to Far East Town Hall Pty Ltd (**Purchaser**) (**Sale Contract**). It is anticipated that the sale of the Ausgrid building will be finalised by 1 July 2014.

The sale of the Ausgrid building as a going concern and the need to enable Ausgrid to transition the relocation of staff and facilities from the Ausgrid building necessitated the lease and licence arrangements referred to in answer to 19.3(b)

The lease for 570 George Street is based on the average rate for commercial office on a per m2 for mid town Sydney CBD. A property valuation was completed by Colliers on behalf of the NSW State Government Divestment team within the Department of Finance. This valuation was based on this rate per m2 contained within the lease for 570 George Street. A copy of the valuation calculation summary is provided on a confidential basis as part of Attachment O.

(b) explain:

(i) why that service is the subject of an arrangement or contract (i.e. why it is outsourced) instead of being undertaken by Ausgrid itself;

See answer to 19.4(a).

(ii) whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement (or similar);

See answer to 19.4(a).

(iii) whether the services were procured on a genuinely competitive basis and if not, why; and

See answer to 19.4(a).

(iv) whether the service (or any component thereof) was further outsourced to another provider.

See answer to 19.4(a).

20. PROPOSED CONTINGENT PROJECTS

20.1 For each contingent project proposed in the regulatory proposal, provide:

(a) a description of the proposed contingent project, including reasons why Ausgrid considers the project should be accepted as a contingent project for the forthcoming regulatory control period;

(b) the proposed contingent capital expenditure which Ausgrid considers is reasonably required for the purpose of undertaking the proposed contingent project;

(c) the methodology used for developing that forecast and the key assumptions that underlie it;

(d) information that demonstrates that the undertaking of the proposed contingent project is reasonably required to meet one or more of the objectives referred to in clause 6.6A.1(b)(1) of the NER;

(e) a demonstration that the proposed contingent capital expenditure for each proposed contingent project:

(i) is not included (either in part of in whole) in Ausgrid's proposed total forecast capital expenditure for the forthcoming regulatory control period;

(ii) reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of the proposed contingent project; and

(iii) exceeds either $30 million or 5 per cent of Ausgrid's proposed annual revenue requirement for the first year of the forthcoming regulatory control period, whichever is larger amount.

(f) the proposed trigger events relating to the proposed contingent project.

20.2 For each proposed trigger event relating to the proposed contingent project referred to in 20.1(f), demonstrate:

(a) the proposed trigger event is reasonably specific and capable of objective verification

(b) the occurrence of the proposed trigger event makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives;

(c) the proposed trigger event generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole;

(d) the proposed trigger event is described in such terms that the occurrence of that event or condition is all that is required for the distribution determination to be amended under clause 6.6A.2 of the NER;

(e) the proposed trigger event is a condition or event, the occurrence of which is probable during forthcoming regulatory control period, but the inclusion of capital expenditure in relation to the proposed trigger event under clause 6.5.7 of the NER is not appropriate because:

(i) it is not sufficiently certain that the event or condition will occur during the forthcoming regulatory control period or if it may occur after that regulatory control period or not at all; or

(ii) the costs associated with the event or condition are not sufficiently certain.

20.3 Provide a summary of Ausgrid's proposed contingent projects for the forthcoming regulatory control period including the proposed contingent capital expenditure and trigger events for each proposed contingent project in the regulatory template 7.2.

Ausgrid's regulatory proposal for the forthcoming regulatory period does not contain any contingent projects.

21. NON-NETWORK ALTERNATIVES

21.1 Identify the Policies and Strategies and Procedures which relate to the selection of efficient non-network solutions.

The Ausgrid policies, strategies and procedures relevant to the consideration of cost effective non-network options are provided as follows:

- Ausgrid Demand Management Policy
- Ausgrid Demand Management Standard
- Ausgrid Demand Management Engagement Strategy.

These documents are provided in full as attachments to this response document, at Attachment P Demand Management Policies.

21.2 Explain the extent to which the provision for efficient non-network alternatives has been considered in the development of the forecast capex proposal and the forecast opex proposal.
Regulatory Proposal

1. Development of the Targeted DM Program

For Ausgrid's Targeted Demand Management (DM) program, where non-network options have been selected to defer specific capital projects within the 2014-19 period, this information is provided in Attachment 6.12, and repeated below.

Ausgrid develops strategic business plans for meeting the expected needs for electricity services in each of 28 defined geographic areas covering the Ausgrid network. These Subtransmission Area Plans cover a 20 year forward planning horizon, and are reviewed every two to three years.

Based on the most recent demand forecast information, strategy options are developed to meet network needs taking into account relevant planning criteria, asset replacement requirements, and infrastructure compliance issues. A preferred strategy option is selected based on the lowest net present cost that will meet all the relevant network needs in the area.

For each of the strategy options within an Area Plan, demand management options are included alongside supply side options in developing the suite of potential projects to meet the relevant network needs. Generally at the Area Plan stage there is little or no specific information known about actual demand management options available in the area, so assumptions are made about the likely scale and cost based on previous experience with development of actual demand management programs. The demand management programs are then incorporated into the Area Plan strategies as non-network operating expenditure where they can be identified and are considered to be cost effective, and the relevant capital projects are deferred. The potential for deferral of all demand driven capital projects above $1m are considered in this process. For the 2015-19 period these costs are then included in the Capital Project Plan expenditures.

For the 11kV and LV Plan, details of specific capital projects for the 2014-19 period are not known at the time of development of the regulatory reset proposal. In this case an estimate of DM expenditure for the 11kV Distribution System in the 2014-19 period has been estimated based on expenditure in the current regulatory period, and scaled according to the relative level of growth driven 11kV investment proposed.

2. Development of the Broad-Based DM Program

Ausgrid has developed a Broad-Based DM program to address emerging constraints to achieve benefits primarily beyond the 2014-19 period.

A suite of program options have been developed with reference to DM trial outcomes and shared knowledge in Broad-Based DM deployment obtained from Queensland DNSPs in their current regulatory period. The proposed level of investment is relatively modest in recognition that this is a first step of a new category of demand management and a step change compared to the previous regulatory period. Program options include Power Factor Correction and OP2 rescheduling, which are very low cost DM options and are considered to be suitable for wide deployment across the Ausgrid network area. However to attain sufficient magnitude of demand reductions in specific areas to achieve deferral benefits, additional DM solutions are necessary, and we have proposed a mix of program options in the Broad-Based DM Plan, both residential and non-residential, that can be directed to areas of emerging network constraints and suited to the predominant customer type and time of day of peak for that area.

Broad-based programs will be focussed in the regions of the network identified to have emerging constraints in a ten year horizon. These emerging constraints are identified in the Area Planning process and actual expenditure will be scaled to any changes in demand forecasts and the needs of the network.

In completing the business case for these programs, full market benefits are considered, including the expected capex deferred in the distribution, transmission and generation sectors, and these are based on average costs of providing additional capacity in each case. The Broad-Based DM business case has a minimum benefit to cost ratio of 2.0 over the ten year time period.

The impacts of Broad-Based DM programs have been incorporated into the spatial demand forecast used in the development of the network capital works plans.

21.3 Identify each non-network Project that Ausgrid has:
(a) commenced during the current regulatory control period; and
(b) selected to commence during, or will continue into, the Forthcoming regulatory control period.

This information is included in Attachment 6.12, specifically:

- Section 1.3 (page 16-17) for targeted DM projects in 2009-14 regulatory period
- Section 4.3 (page 36) for targeted DM projects in the 2014-19 regulatory period.

The relevant information has been extracted from the DM Opex Proposal and shown below:

a) Non-network projects commenced in 2009-14 Period

Wollombi Generator Project

This project consisted of a 1MW relocatable diesel generator to provide voltage support to a long rural feeder in the Wollombi area by reducing demand at times of high load. The program was completed in 2011/12 at a cost of $802,600 in the 2009-14 regulatory period.

Warringah STS DM Project

This program focused on reducing load at risk at Warringah STS in winter 2009, prior to construction of the $51m Balgowlah Zone Substation. It consisted of three elements a network support agreement with Sydney Water for a 1.4MW cogeneration system, a dispatchable network support agreement with a third party aggregator, and installation of leased diesel generators. The program was completed in 2009/10 at a cost of $841,900 in the 2009-14 regulatory period.

Nelson Bay Generator Project

This project involved the installation of 3MVA of diesel generators connected to an 11kV feeder in order to reduce demand in the Nelson Bay area in summer 2009/10. This enabled an alternate strategy for the supply to the Nelson Bay area that was substantially less expensive to other proposed options. The program was completed in 2009/10 at a cost of $591,700 in the 2009-14 regulatory period.

Adamstown DM Project

This project consisted of the installation of 2.4MVA of temporary diesel generation at the existing Broadmeadow Zone Substation in the Newcastle area. The objective was to reduce demand on this substation in summer 2009/10, which was forecast to be above the applicable planning design criteria, prior to construction of the new $26.2m Adamstown Zone Substation. The program was completed in 2009/10 at a cost of $434,600 in the 2009-14 regulatory period.

Greenacre Park DM Project

This program focused on reducing load at risk at Greenacre Park Zone Substation in summers 2009-10 & 2011/12 prior to the construction of the $51m Potts Hill Zone Substation. It consisted of a network support contract with customer standby generators, and a relatively small customer power factor correction program. Total costs for the DM program were $1.46m in the 2009-14 regulatory period.

Terry Hills PFC and Generation Project

This program consisted of two elements - installation of 3MW of embedded relocatable generators and a customer power factor correction (PFC) program. The objective was to reduce demand on the 33kV network supplying Terrey Hills and several other zone substations from Sydney East subtransmission substation (STS) in winter 2009, enabling the deferral of an $8m investment in a new 33kV feeder to Terrey Hills Zone Substation by one year. The total cost of the DM program in the 2009-14 regulatory period was $219,100.

Willoughby STS DM Project

This program consisted of two elements a non-dispatchable network support agreement with a gas-fired cogeneration site, and a customer power factor correction program in Sydney's Lower North Shore area supplied by Willoughby STS. The objective was to reduce demand on Willoughby STS by 6.3MVA in summer 2009/10 & 2.6MVA in summer 2010/11, to reduce load at risk until the commissioning of a new zone substation at a cost of $53.7m. The total cost of the DM program was $674,500 over two years.

North West Pennant Hills Generator Project

This program consisted of the installation of between 0.4MVA & 0.8MVA of temporary diesel generators in the summer season over a three year period from 2010/11 to 2012/13. The objective was to maintain network performance in the North West Pennant Hills area, enabling the deferral of a proposed $3.8m in laying new 11kV cable from Pennant Hills Zone Substation to an area north of Cherrybrook. The program completed in summer 2012/13 was the third stage of a proposed five year program.

The total cost of the DM program was $743,000 over three years. Due to a subsequent reduction in the demand forecast for the area at this time, it was determined that the need for the network capacity upgrade had been deferred indefinitely, effectively avoiding the need for the $3.8m capital project completely. This is an excellent example of the option value of DM in managing the uncertainty related to future demand growth.

Medowie DM Project

This program consists of installation of 5.0MVA of temporary diesel generators and 62kVA of power factor correction in the summer seasons of 2011/12 and 2012/13, and 2.5MVA of temporary diesel generators in summer 2013/14. The objective was to reduce load at risk in the Medowie area, prior to the construction of the new $29.6m Medowie Zone Substation. The total cost of the DM program was $2.19m.

b) Non-network projects proposed to commence in 2014-19 Period

Load Transfer from Tarro Zone Substation

Demand growth at Tarro Zone Substation in the Lower Hunter Region is forecast to exceed the relevant capacity limits in Summer 2017/18. The preferred Area Plan Strategy includes a project for 11kV cable works to transfer up to 15MVA of load from Tarro to an adjacent zone substation at a cost of almost $12m. We have determined that it will be cost effective to defer the load transfer works for at least two years by implementing 1.4MVA of DM options.

At this point in time we do not know the exact type of DM options that will be implemented in the Tarro area, however this will be determined from the investigation, consultation & assessment process. The total estimated cost of this DM program in the 2014-19 regulatory period is $500,000.

Upgrade of 33kV feeder S03 at Manly Warringah

Demand growth at Manly Warringah area in the Sydney Region is forecast to exceed the relevant capacity limits in Summer 2017/18. The preferred Area Plan Strategy includes a project for upgrade of a 33kV feeder to accommodate the demand increase at a cost of $1.6m. We have determined that it will be cost effective to defer the feeder upgrade works for one year by implementing DM options.

At this point in time we do not know the exact type of DM options that will be implemented in the Manly Warringah area, however this will be determined from the investigation, consultation & assessment process. The total estimated cost of this DM program in the 2014-19 regulatory period is less than $50,000.

11kV Distribution Plans

Because the specific demand driven capital investments in the 11kV Distribution System are not known at the time of the regulatory reset, DM expenditure for the 11kV Distribution System in the 2015-19 period has been estimated based on expenditure in the current regulatory period, and scaled according to the relative level of growth driven 11kV investment proposed in 2015-19 period. This has been estimated at $1.5 million ($, 2013-14) for the 2015-19 period. At this point in time we do not know the exact location and type of DM options that will be implemented to defer 11kV capital investments in 2014-19.

21.4 For each non-network Project identified in the response to paragraph 21.3, provide a description, including cost and location.

See response to Item 21.3 above.

21.5 Provide, for each year of the current regulatory control period, and for the forthcoming regulatory control period, details of each payment made, or expected to be made, by Ausgrid to an Embedded Generator in reflection any costs avoided by deferring augmentation of:

(a) Ausgrid's distribution network; or

(b) the relevant transmission network.

See Table 28 below for a summary of payments to generators in the current regulatory period.

In addition to the listed payments, a number of payments were made to generators as part of Ausgrid's Dynamic Peak Rebate Trial under the DM Innovation Allowance, however these were not related to avoided or deferred network augmentation.

For the forthcoming regulatory period, Ausgrid proposes to make payments to embedded generators as part of the Broad-Based a[redacted]ed DM Programs, however the amounts and specific generator sites are not known at this point in time. [redacted]s been allocated over the 2014-19 period for demand response and energy efficiency programs in the non-residential sector, and it is likely that a significant proportion of this amount will be paid to embedded generators as part of network support agreements.

Table 28 Ausgrid summary of payments to embedded generators in 2009-14

						Generator Payment ($)
[redacted]						

[redacted]

22. EFFICIENCY BENEFIT SHARING SCHEME

22.1 To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Ausgrid's current regulatory control period:

(a) provide the forecast and actual operating expenditure amounts in regulatory template 7.5;

(b) identify all changes to Ausgrid's Capitalisation Policy during the current regulatory control period.

Information reported in table 7.5.1 is in accordance with the Regulatory Accounting statements as well as Ausgrid's CAM and Ausgrid's PTRM model. Ausgrid prepares Standard Control Services Annual Regulatory Statements for AER which comply with Australian Accounting Standards and the Regulatory Information Requirements Guidelines for the NSW Electricity Distributors. These are independently audited and reviewed each year before reporting separately to the AER. The Regulatory Accounting Statements include Standard Control Services (Distribution) and Standard Control Services (Transmission) and Alternative Control Services (Public Lighting).

No changes to Ausgrid's Capitalisation Policy occurred during the currently regulatory control period.

22.2 For each change identified in the response to paragraph 22.1(b):

(a) state, if any, the financial impact of the change;

(b) state the reasons for the change;

(c) explain the effect of the change, if any, on the forecast operating expenditure for each year of Ausgrid's current regulatory control period; and

(d) explain the effect of the change, if any, on the actual operating expenditure for each year of Ausgrid's current regulatory control period.

No changes to Ausgrid's Capitalisation Policy occurred during the currently regulatory control period.

22.3 For the purposes of applying the efficiency benefit sharing scheme:

(a) identify all cost categories proposed to be excluded from the operation of the efficiency benefit sharing scheme;

Ausgrid does not propose to have any cost categories to be excluded from the operation of the EBSS. As noted in our regulatory proposal, we have used the base year approach to forecasting opex and the base year used is the actual outturn opex for 2012-13. We have excluded from this base amount the component of long service leave costs relating to actuarial assessment. Consequently Ausgrid also proposed that, in relation to the operation of the EBSS, the actual outturn opex of each year be adjusted to account for any actuarial assessment for long service leave obligations.

(b) explain for each cost category identified in the response to paragraph 22.3(a) the reasons for the proposed exclusion.

This adjustment is necessary to ensure comparability between forecast opex allowances and actual outturn opex, and ensure accuracy of the calculation of the difference between forecast opex and actual outturn opex so that the efficiency gain/loss of a particular year is not distorted. This will also ensure the DNSP is not rewarded /penalises unduly for incompatibility between forecast opex and actual outturn opex.

23. SERVICE AND QUALITY

23.1 Provide Ausgrid's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS);

(a) the SAIDI, SAIFI and MAIFI targets for each supply reliability area;

Ausgrid calculates unplanned SAIDI and unplanned SAIFI targets in accordance with clause 3.2.1 of the STPIS for each network type. Ausgrid is proposing a variation to exclude MAIFI from the STPIS for the 2015-19 regulatory control period. Therefore, MAIFI targets have not been calculated.

Unplanned SAIDI and unplanned SAIFI for each network type are forecast with Ausgrid's Reliability Forecast System (RFS). The RFS is based on raw historical data from Ausgrid's completed regulatory template 6.2 "Reliability and Customer Service". The raw data has had exclusions under clause 3.3 and Appendix D of the STPIS applied. The RFS takes into account completed and planned reliability improvements that are:

- Included in the expenditure program proposed by Ausgrid in regulatory proposal, or
- Proposed by Ausgrid (and the cost of improvements is allowed) in the previous regulatory proposal, and
- Expected to result in material improvements to supply reliability.

Other factors that affect reliability performance are also taken into account. Ausgrid's completed regulatory template 6.2 contains the outputs of the RFS for 2013-14 to 2018-19. The RFS methodology is provided in supporting document ID68195 to Ausgrid's regulatory proposal (Feeder Category Reliability Forecast Methodology).

The unplanned SAIDI and unplanned SAIFI are set to the results of the RFS. If the results of the RFS indicate deterioration in performance, the targets are adjusted to be equal to the forecast value of the previous regulatory year.

(b) the customer service parameters and targets;

This has been provided in section 4 of Attachment 3.02 Application of STPIS to Ausgrid's regulatory proposal.

(c) daily SAIDI, SAIFI, MAIFI and customer service performance derived from the individual interruption data under 23.2;

Daily unplanned SAIDI is calculated by summating the "Effect on unplanned SAIDI" column in Ausgrid's completed regulatory template 6.3 "Sustained interruptions to supply". The values are summed for each day in the 2008-09 to 2012-13 regulatory years. Any interruption that spans multiple days is accrued to the day on which the interruption begins. Planned interruptions and excluded interruptions under clause 3.3 (a) of the STPIS are not included in the calculation.

Daily unplanned SAIFI is calculated by summating the "Effect on unplanned SAIFI" column in Ausgrid's completed regulatory template 6.3 "Sustained interruptions to supply". The values are summed for each day in the 2008-09 to 2012-13 regulatory years. Any interruption that spans multiple days is accrued to the day on which the interruption begins. Planned interruptions and excluded interruptions under clause 3.3 (a) of the STPIS are not included in the calculation.

Ausgrid is proposing a variation to exclude MAIFI from the STPIS for the 2015-19 regulatory control period, therefore daily MAIFI performance has not been calculated.

(d) the MED threshold derived from the daily SAIDI data;

Ausgrid proposes to derive MED thresholds at the end of each regulatory year for use during the next regulatory using the 2.5 beta method in accordance with Appendix D of the STPIS. The daily unplanned SAIDI performance derived from the individual interruption data under 23.2 is used as the input to calculate the 2013-14 MED threshold. Subsequent MED thresholds will be calculated at the end of each regulatory year using the same calculation r

Ausgrid has applied the Anderson-Darling statistical test to the daily unplanned SAIDI data to determine the goodness-of-fit of a range of probability distributions. It was found that the lognormal distribution had the best fit of all tested distributions. Therefore, Ausgrid is not proposing an alternative data transformation method and step 4 (b) of Appendix D of the STPIS will be followed.

(e) The incentive rates to apply to each supply reliability area.

The incentive rates for unplanned SAIDI and unplanned SAIFI are calculated in accordance with clause 3.2.2 of the STPIS for each network type. Ausgrid is proposing a variation to exclude MAIFI from the STPIS for the 2015-19 regulatory control period. Therefore, MAIFI incentive rates have not been calculated.

Ausgrid utilises the formulae provided in Appendix B of the STPIS. Ausgrid is not proposing an alternative VCR or network type segmentation. The sources for input parameters required in the formulae are detailed in the following table.

Table 29 Source for STPIS input parameters

Parameter	Source / calculation method
VCR	The VCRs provided in clause 3.2.2(b) of the STPIS
CPI	CPI as applied to regulatory price setting
w_n	Weighting for unplanned SAIDI and unplanned SAIFI in Table 1 of the STPIS
C_n	The expected average annual energy consumption by network type for the 2015-19 regulatory control period. This is calculated according to the following method: 1. Calculate the 2012-13 annual energy consumption for each network type (by summating the energy consumption of active customers connected to each network type) 2. Determine the ratio of total energy delivered in 2012-13 to the forecast total energy delivered in 2014-15 (from Ausgrid's completed regulatory template 3.4) 3. Multiply the 2012-13 annual energy consumption for each network type by the ratio from step 2 in order to determine the forecast energy consumption by network type for 2014-15 4. Repeat steps 2 and 3 for regulatory years 2015-16 to 2018-19 5. Calculate the expected average annual energy consumption for the 2014-15 to 2018-19 regulatory period for each network type (Note: Ausgrid does not forecast energy consumption by network type)
R	The average of the smoothed annual revenue requirement for the 2015-19 regulatory control period as determined by the AER.
$SAIDI_n$	The average of Ausgrid's proposed unplanned SAIDI targets for the 2015-19 regulatory control period.
$SAIFI_n$	The average of Ausgrid's proposed unplanned SAIFI targets for the 2015-19 regulatory control period.

Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.

23.2 Details of all interruptions that occurred in the 2008-09 to 2012-13 regulatory years must be provided in regulatory template 6.3, in accordance with the instructions and definitions contained in this Notice and definitions contained in the STPIS.

Details of all sustained interruptions that occurred in the 2008-09 to 2012-13 regulatory years are provided in Ausgrid's completed regulatory template 6.3. Where possible, Ausgrid has calculated parameters in accordance with definitions contained in the Reset RIN and definitions contained in the STPIS. Ausgrid calculates all SAIDI and SAIFI metrics according to the following assumptions:

STPIS Appendix A, Note 1: All SAIDI and SAIFI metrics are calculated using daily customer counts. Ausgrid has consistently adopted this approach because average customer counts do not result in stable metrics suitable for trend analysis due to the constant adding, removing and reconfiguring of feeders.

STPIS Appendix A, Note 2: All unmetered supplies are excluded from the calculation of SAIDI and SAIFI metrics.

STPIS Appendix A, Note 3: All active customers are included in the calculation of SAIDI and SAIFI metrics. All inactive customers are excluded in the calculation of SAIDI and SAIFI metrics. The following assumptions regarding the definition of active and inactive customers have been made:

- Active = Energised + De-energised
- Inactive = Extinct = Deactivated
- De-energised (AER) = Temporary disconnection (Ausgrid)
- Inactive (AER) = Permanent disconnection (Ausgrid).

23.3 If Ausgrid proposes adjustments to the STPIS targets away from those based upon raw historical data Ausgrid must provide:

(a) the reasons for the change;

(b) the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and

(c) the method, basis and empirical data used as justification for the adjustment.

Ausgrid proposes to calculate STPIS targets in accordance with clauses 3.2.1 and 5.3.1 of the STPIS. The targets are based on the average performance over the past five regulatory years. For further information see Attachment 3.02.

24. SHARED ASSETS

24.1 Provide Ausgrid's shared assets information in Regulatory template 7.4.

Ausgrid's shared assets information has been provided in Regulatory template 7.4.

25. REVENUE AND PRICES FOR STANDARD CONTROL SERVICES

25.1 Provide Ausgrid's calculation of the unsmoothed and smoothed revenues, and prices for the purposes of the control mechanism proposed by Ausgrid using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.

Ausgrid has provided its calculation of the unsmoothed and smoothed revenues using the AER's post-tax revenue models submitted as part of the regulatory proposal.

This information is set out in Chapter 4 of Ausgrid's regulatory proposal and in the post-tax revenue model provided at Attachments 4.01 and 4.02. To calculate forecast prices, Ausgrid has used smoothed revenues from the PTRMs (using the revenue smoothing functions) to populate our indicative price model used to determine the indicative prices included in our regulatory proposal and to populate regulatory template 7.7.1.

25.2 Provide details of any departure from the AER's post-tax revenue model for the calculations referred in paragraph 25.1 and the reasons for that departure.

Ausgrid has not departed from the AER's post-tax revenue model, however, it has had to modify its application in some respects to accommodate the AER's decision to recover revenue for certain alternative control services as standard control services in FY14.

26. INDICATIVE IMPACT ON ANNUAL ELECTRICITY BILLS

26.1 For the purposes of calculating the impact of Ausgrid's Regulatory proposal on the annual electricity bill of typical residential and business customers in New South Wales, provide the data/information required in regulatory template 7.6. Provide the data source for each input used for the calculation.

Ausgrid has provided the calculations requested by the AER in Template 7.6.

The information provided is consistent with the requirements of the Reset RIN, instructions and definitions. The requirements include (but are not limited to) the following:

- To provide the data/information required for the purpose of calculating the impact of Ausgrid's regulatory proposal on the annual electricity bill of our typical residential and business customers.
- To provide the data source for each input used for the calculation.

Input Data and sources used to calculate our indicative Distribution Use of system bill outcomes for residential and small business customers in each year of the next regulatory control period

Ausgrid's calculation of the indicative bill impacts for our typical residential and business customers in each year of the next regulatory control period is based on the following information:

1. EnergyAustralia's regulated retail for residential customers in FY 2013/14. This information has been sourced from the EnergyAustralia website, see link below:
    - http://www.energyaustralia.com.au/servlet/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobheadername1=Content-Disposition&blobheadervalue1=attachment%3B+filename%3D%22Residential+prices.pdf%22&blobkey=id&blobtable=MungoBlobs&blobwhere=1343702898052
2. EnergyAustralia's regulated retail for business customers in FY 2013/14. This information has been sourced from the EnergyAustralia website, see link below:
    - http://www.energyaustralia.com.au/servlet/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobheadername1=Content-Disposition&blobheadervalue1=attachment%3B+filename%3D%22Small+business+prices.pdf%22&blobkey=id&blobtable=MungoBlobs&blobwhere=1343702898066&ssbinary=true
3. Ausgrid's Distribution Use of System (DUOS) Tariffs for FY 2013/14. This information has been sourced from Table 3a on page 33 of the Ausgrid's annual pricing proposal document website, see link below:
    - http://www.ausgrid.com.au/Common/Our-network/Network-prices/~/media/Files/Network/Electricity%20Supply/Network%20Pricing/201314%20Pricing%20Proposal.pdf
4. The proposed Forecast smoothed revenue in each year of the next regulatory control period. This information has been sourced from the Ausgrid's PTRM and our Indicative Pricing Model.

Assumptions made to calculate our indicative Distribution Use of system bill outcomes for residential and small business customers in each year of the next regulatory control period

Ausgrid's calculation of the indicative bill impacts for our typical residential and business customers in each year of the next regulatory control period is based on the following assumptions:

1. The DNSP does not undertake any tariff reform in the forecast period.
2. The volumes at the tariff component level change at the same rate as the overall volumes.
3. There is no volume forecasting error. i.e. no actual over/under recovery of DUOS revenue during the forecast period.
4. Typical residential customer consumes 5,000 kWh of energy per annum and consumes 1,050 kWh in the peak period, 2,550 kWh in shoulder period and 1,400 kWh in the off-peak period.
5. Typical small businee customer consumes 10,000 kWh of energy per annum and consumes 2,100 kWh in the peak period, 5,100 kWh in shoulder period and 2,800 kWh in the off-peak period.
6. A forecast CPI assumption of 2.5% has been applied to each year of the next regulatory control period.
7. Metering charges for Type 5-6 metering services have been included in the calculation for all years to ensure comparability to year 13/14 required by the template.

Methodology for calculating indicative Distribution Use of system bill outcomes

In general terms, the forecast of Distribution Use of System (DUOS) bill outcomes for residential and small business customers have been calculated for FY 2013/14 on the basis of following basis:

1. **Step One**: Calculate the regulated retail bill outcome in FY 2013/14.

Ausgrid has calculated the regulated retail bill outcomes for a customer with typical consumption in FY 2013/14 for the tariffs below:

- EnergyAustralia All time Residential Tariff
- EnergyAustralia Power Smart Home Residential Tariff
- EnergyAustralia General Supply All time Residential Tariff
- EnergyAustralia Power Smart Business Tariff.

Ausgrid has calculated the above-mentioned regulated retail bill outcomes in FY 2013/14 using the following method, as expressed in formulaic terms:

$$\mathrm{Re}tail_t = \sum_{i=1}^{m} p_t^i q_t^i$$

Where:

$Retail_t$	is the annual bill for a typical customer on a regulated retail tariff in year t
P^t_i	is the price of component i of regulated retail tariff in year t
q^t_i	is the assumed quantity of component i of regulated retail tariff in year t
t	Financial year ending 30 June 2014
m	Total number of components of the regulated retail tariff

2. **Step Two**: Calculate the Distribution Use of System bill for a typical customer in FY 2013/14

Ausgrid has calculated the Distribution Use of System bill outcomes for a customer with typical consumption in FY 2013/14 for the following tariffs:

- Ausgrid Residential Inclining Block Tariff
- Ausgrid Residential Time of Use Tariff

- Ausgrid Small Business Inclining Block Tariff
- Ausgrid Small Business Time of Use Tariff.

Ausgrid has calculated the above-mentioned distribution use of system bill outcomes in FY 2013/14 using the following method, as expressed in formulaic terms:

$$Dist_t = \sum_{i=1}^{m} p_t^i q_t^i$$

Where:

$Dist_t$	is the annual bill for a typical customer on a distribution use of system tariff in year t
P^t_i	is the price of component i of distribution use of system tariff in year t
q^t_i	is the assumed quantity of component i of distribution use of system tariff in year t
t	Financial year ending 30 June 2014
m	Total number of components of the distribution use of system tariff

3. **Step Three**: Calculate the percentage share accounted for by the DUOS bill in the regulated retail bill for a typical customer in FY 2013/14

Ausgrid has calculated the percentage share accounted for by the DUOS bill in the regulated retail bill for a typical customer using the following method, as expressed in formulaic terms:

$$D_t = \frac{Dist_t^r}{Retail_t^r} + \frac{Dist_t^{r(i)}}{Retail_t^{r(i)}} + \frac{Dist_t^b}{Retail_t^b} + \frac{Dist_t^{b(i)}}{Retail_t^{b(i)}} \times \left[\frac{1}{4}\right]$$

Where:

D_t	is the share of the DUOS bill in the regulated retail bill in year t
$Dist^r$	is the share of the DUOS bill for a typical customer on the residential IBT in year t
$Dist^{r(i)}$	is the share of the DUOS bill for a typical customer on the residential TOU tariff in year t
$Dist^b$	is the share of the DUOS bill for a typical customer on the small business IBT in year t
$Dist^{b(i)}$	is the share of the DUOS bill for a typical customer on the small business TOU tariff in year t
t	Financial year ending 30 June 2014

4. **Step Four**: Calculate the indicative Distribution Use of System bill for a typical customer in FY 2013/14

Ausgrid has calculated the indicative Distribution Use of System bill for a typical customer in FY 2013/14

$$Dist(I)_t = Retail_t \times D_t$$

Where:

Dist(I)t	is the indicative annual Distribution Use of System bill for a typical customer in year t
Retailt	is the annual bill for a typical customer on a regulated retail tariff in year t (as per Step One)
Dt	is the share of the DUOS bill in the regulated retail bill in year t (as per Step Three)
t	Financial year ending 30 June 2014

Step Five: Calculate the indicative Distribution Use of System bill outcome for a typical customer in each year of the next regulatory control period

Ausgrid has calculated the indicative Distribution Use of System bill outcome for the above-mentioned tariffs for a typical residential and small business customer in each year of the next regulatory control period using the following method, as expressed in formulaic terms::

$$Dist(I)_t = Dist(I)_{t-1} \times g_t$$

$$g_t = \left[\frac{ap_t}{ap_{t-1}} \right] - 1$$

$$ap_t = \left[\frac{R_t}{Q_t} \right]$$

Where:

$Dist(I)_t$	is the indicative annual Distribution Use of System bill for a typical customer in year t
$Retail_t$	is the annual bill for a typical customer on a regulated retail tariff in year t (as per Step One)
g_t	is the growth rate in year t
ap_t	Average price in year t
ap_{t-1}	Average price in year t-1
R_t	Forecast Smoothed Revenue in year t
R_{t-1}	Forecast Smoothed Revenue in year t-1
Q_t	Forecast Total Energy Consumption in year t
t	Financial year that the indicative distribution bill outcome is calculated
t-1	Financial year prior to the year that the indicative distribution bill outcome is calculated

27. REGULATORY ASSET BASE

27.1 Provide Ausgrid's calculation of the regulatory asset base for the relevant distribution system in respect of standard control services for each regulatory year of current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal

Ausgrid has provided the calculation of its regulatory asset base as required by paragraph 27.1 of the RIN in its regulatory proposal. Please refer to Chapter 4 of Ausgrid's regulatory proposal as well as Attachments 4.03 and 4.04.

27.2 Provide details of any departure from the underlying methods in the AER's roll forward model for the calculation referred in 27.1 and the reasons for that departure.

Ausgrid has departed from the underlying methods in the AER's roll forward model for the calculations referred to in 27.1 as follows:

- As approved by the AER, Ausgrid has used the distribution roll forward model for its transmission assets.
- Ausgrid has departed from the RFM to calculate the opening tax asset base as at 1 July 2014. Refer to Attachment 4.08 of Ausgrid's regulatory proposal for more information.
- Ausgrid has also used a separate approach to estimating tax remaining life from that set out in the AER's roll forward model. The details of this are outlined in Attachment 4.08 of Ausgrid's regulatory proposal for more information.

27.3 If the value of the RAB as at the start of the forthcoming regulatory control period is proposed to be adjusted because of changes to asset service classification, provide details including relevant supporting information used to calculate that adjustment value.

Ausgrid's Regulatory Asset Base has been adjusted for the change in classification of assets relating to the provision of type 5 and 6 metering services. The process by which we have adjusted the RAB to remove these assets is outlined in Attachments 4.05 and 8.17 to the regulatory proposal.

28. DEPRECIATION SCHEDULES

28.1 Provide Ausgrid's calculation of the depreciation amounts for the relevant distribution system in respect of standard control services for each regulatory year of:

(a) the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal

(b) the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.

Ausgrid's calculation of the depreciation amounts for the 2009-14 period is as set out in the Roll Forward Model, and for the 2014-19 period in the PTRMs submitted as part of the regulatory proposal at Attachments 4.01 and 4.02. These calculations are further explained in Attachment 4.07 Nominated Depreciation Schedules.

28.2 Provide details of any departure from the underlying methods in the AER's roll forward model and post-tax revenue model for the calculations referred to in 28.1 and the reasons for that departure.

For the purposes of 28.1, Ausgrid has not departed from the underlying methods in the AER's roll forward model and post-tax revenue model.

28.3 Identify any changes to standard asset lives for existing asset classes from the previous determination. Explain the reason/s for the change and provide relevant supporting information.

There have been no changes to standard asset lives for existing asset classes from the previous determination.

28.4 For any proposed new asset classes, explain the reason/s for using these new asset classes and provide relevant supporting information on their proposed standard asset lives.

Ausgrid has not proposed any new asset classes.

28.5 If existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes, explain the reason/s for the change and provide relevant supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.

Ausgrid has not proposed to remove any existing asset classes from the previous determination

28.6 Describe the method used to calculate the remaining asset lives for existing asset classes as at 1 July 2014 (the start of the forthcoming regulatory control period) and provide supporting calculations if the approach differs from that in the roll forward model.

Ausgrid has used the same method to calculate remaining asset lives as set out in the Transmission Roll Forward Model published in December 2010.

29. CORPORATE TAX ALLOWANCE

29.1 Provide Ausgrid's calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.

This has been provided in Chapter 4 of Ausgrid's regulatory proposal. The relevant calculations are detailed in the distribution and transmission post tax revenue model attachments to the regulatory proposal, at Attachment 4.01 and 4.02.

29.2 Provide a demonstration that the calculation referred to in 29.1 complies with clause 6.5.3 of the NER.

The calculation of the corporate tax allowance referred to in 29.1 complies with National Electricity Rule 6.5.3 – demonstration of this is provided in the distribution and transmission PTRM attachments to the regulatory proposal, at attachments 4.02 and 4.02.

29.3 Provide details of any departure from the AER's post-tax revenue model for the calculations referred to in 29.1 and the reasons for that departure.

Ausgrid has not proposed any departures from the AER's post-tax revenue model for the calculations referred to in 29.1.

29.4 Identify any changes to standard tax asset lives for existing asset classes from the previous determination. Explain the reason/s for the change and provide relevant supporting information, including Federal tax laws governing depreciation for tax purposes.

Ausgrid has not proposed any changes to the tax standard lives for existing asset classes from the previous determination.

29.5 Describe the method used to calculate the remaining tax asset lives as at 1 July 2014 and provide supporting calculations, if the approach differs from that in the AER's roll forward model.

Tax remaining lives were not approved in the 2009-14 determination for the opening tax asset base as at 1 July 2009. As a result it was not possible to use the AER's preferred approach set out in the AER's transmission roll forward model. Ausgrid has calculated tax remaining lives by applying the proportion of regulatory remaining lives to regulatory standard lives (for the principal RAB) to the tax standard lives approved in the 2009-14 determination. This approach is outlined in Attachment 4.08 Approach to Opening Tax Asset Base and Remaining Tax Asset Lives as at 1 July 2014 and is demonstrated in the distribution and transmission PTRM attachments to the regulatory proposal.

29.6 Provide Ausgrid's calculation of the tax asset base for the relevant distribution system in respect of standard control services for each regulatory year of the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.

Ausgrid's approach to estimating the tax asset base for each regulatory year of the current regulatory period is outlined in Attachment 4.08 Approach to Opening Tax Asset Base and Remaining Tax Asset Lives as at 1 July 2014. This approach is reflected in Ausgrid's distribution and transmission roll forward model attachments to the regulatory proposal.

29.7 Provide details of any departure from the underlying methods in the AER's roll forward model for the calculation referred to in 29.6 and the reasons for that departure.

Ausgrid has departed from the method outlined in the AER's roll forward model for calculating depreciation on the opening tax asset base as at 1 July 2009. This was because tax remaining lives were not approved as part of the 2009-14 determination. Depreciation on the opening tax asset base has been hardcoded into the distribution and transmission roll forward models. Ausgrid's approach is outlined in Attachment 4.08 Approach to Opening Tax Asset Base and Remaining Tax Asset Lives as at 1 July 2014.

29.8 Identify any differences in the capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes. Provide reasons and supporting calculations to reconcile any differences between the two forms of accounts

There are no differences in Ausgrid's capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes.

29.9 Provide calculations to demonstrate if a tax loss carried forward exist as at 1 July 2014. The figures used in these calculations, such as the revenue and operating expenses, should be actuals (with the exception of the final year of the current regulatory control period that requires an estimate). Identify and provide reasons for any assumptions applied to determine the value of any tax loss carried forward.

Ausgrid has not proposed any tax loss carried forward as at 1 July 2014.

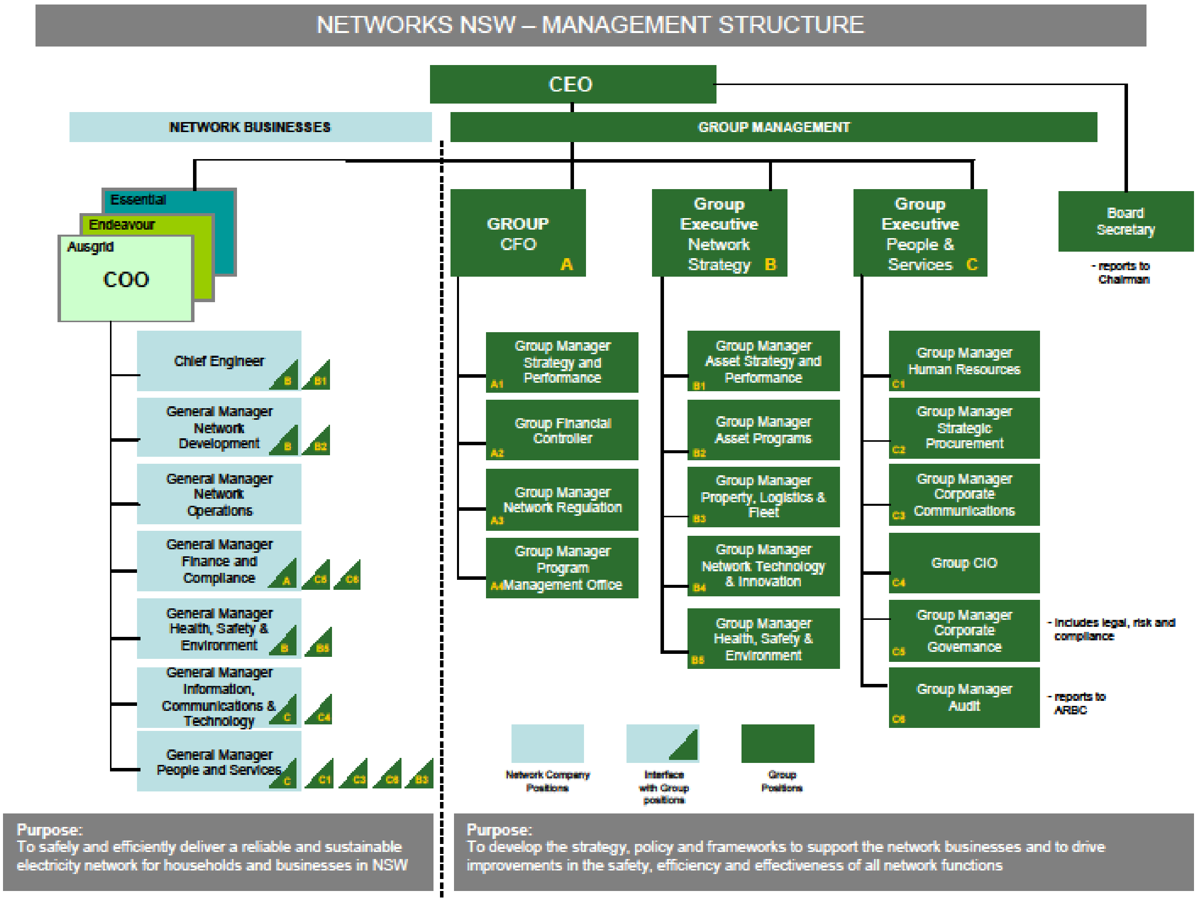
30. CORPORATE STRUCTURE

30.1 Provide charts that set out:

(a) the group corporate structure of which Ausgrid is a part; and

Figure 4 below shows the group corporate structure of which Ausgrid is a part, as at 15 May 2014.

Figure 4 Group corporate structure



(b) the organisational structure of Ausgrid.

Figure 5 below shows the organisational structure of Ausgrid (down to level 4 managers), as at 15 May 2014.

Figure 5 Ausgrid's organisational structure

- Chief Operating Officer
  - Chief Engineer
    - Manager Electrical Safety & Authorisations
    - Manager Primary Systems
    - Manager Secondary Systems
    - Manager Asset & Network Planning
    - Manager Network Data & Performance
  - GM Network Development
    - Program Director Network Maintenance
    - Program Director Capital Programs
    - Program Director Major Projects
    - Manager Portfolio Management Office
    - Manager Project Development
  - GM Network Operations
    - Manager System Control
    - Manager Operational Performance
    - Manager Network Connections
    - Regional Manager North
    - Regional Manager South
    - Regional Manager Central
    - Manager Transmission Services
  - GM Health, Safety & Environment
    - Manager HSE Management Systems & Reporting
    - Manager Safety & Environmental Services
    - Manager Health & Injury Management
    - Manager HSE Assurance & Improvements
  - GM Information Communication & Technology
    - Manager Governance & Service Management
    - Manager Strategy & Architecture
    - Manager Vendor & Sourcing
    - Manager Infrastructure Services
    - Manager Business Systems
    - Manager Distribution Systems & Telecommunica tion
  - GM Finance & Compliance
    - General Counsel
    - Financial Controller
    - Manager Finance Transactions & Services
    - Manager Commercial & Decision Support
    - Manager Governance Risk & Compliance
    - Manager Network Regulation
    - Manager PMO & Corporate Planning
    - Executive General Manager Shared Services
  - GM People & Services
    - Manager Internal Audit
    - Manager Property & Fleet
    - Manager Employee Relations
    - Manager Learning & Development
    - Manager Procurement & Logistics
    - Manager Human Resource Operations
    - Manager Corporate Affairs

31. FORECAST MAP OF DISTRIBUTION SYSTEM

31.1 Provide a forecast map of Ausgrid's distribution system for the forthcoming regulatory control period. This map, together with any appropriate accompanying notes, should also indicate the location of new major network assets proposed to be constructed over the forthcoming regulatory control period.

As per the supporting document to Ausgrid's proposal ID27832 Area Plan Projects - Annual Review of preferred strategies, a major project during the 2014-19 regulatory period is defined as one with expenditure over $25 million during the 2014-19 regulatory period.

As such, the map in Figure 6 indicates the location of all new major network assets proposed to be constructed by Ausgrid over the forthcoming regulatory control period as part of these major projects.

Table 30 following the map details the major projects and associated new major network assets.

Figure 6 Forecast map of distribution system

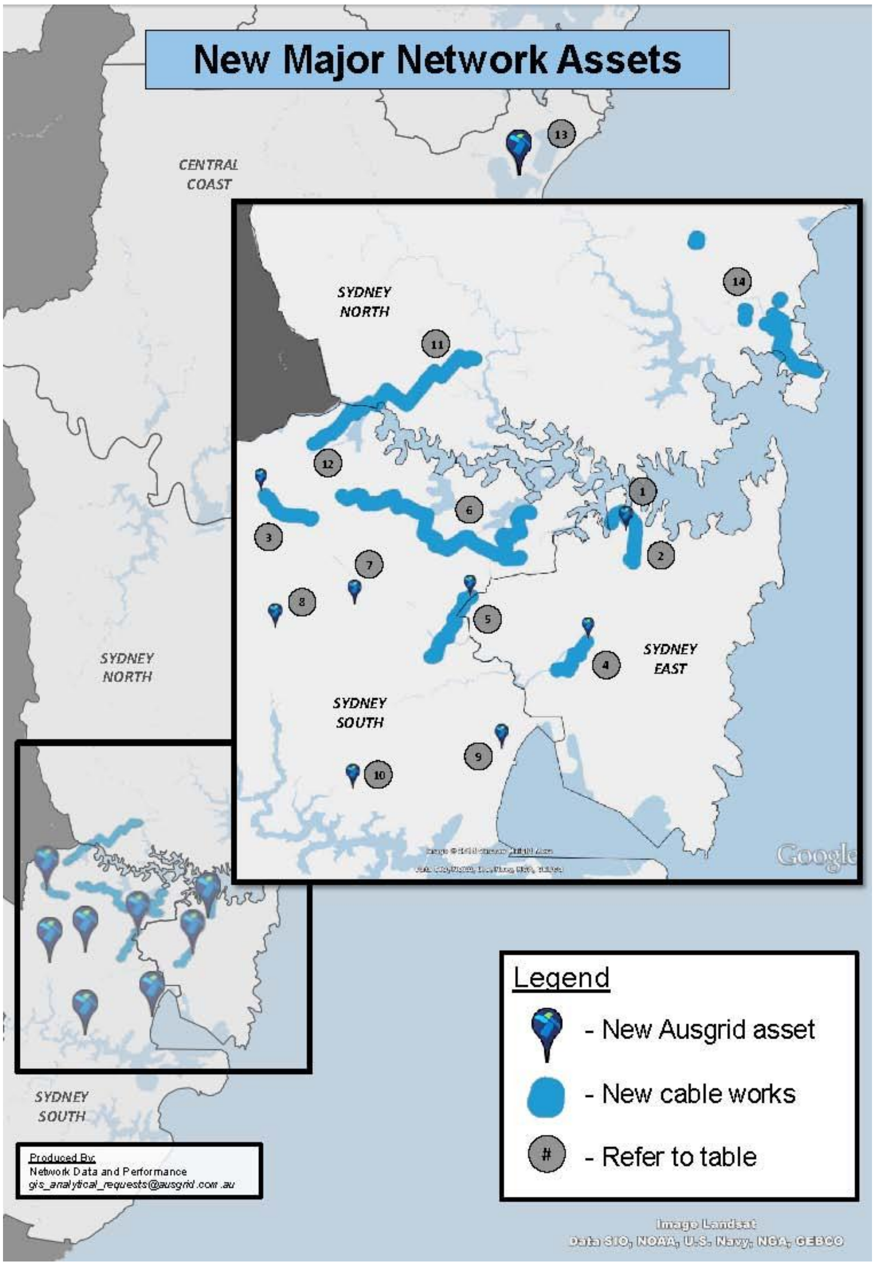


Table 30 Details of new major assets

No.	Project ID	Project name	New Asset Name
1	ARA_2.1.0123 ARA_2.1.0125 ARA_2.1.0126 ARA_2.1.0135A	New Bligh St ZS, associated 132kV connections, 11kV load transfers and Dalley St ZS retirement	Bligh St zone substation
2	ARA_2.1.0108	Eastern CBD tunnel	Eastern CBD tunnel
3	ARA_4.4.C.0008 ARA_4.4.C.0009 ARA_4.4.C.0026A ARA_4.4.C.0028A ARA_4.4.C.0032A ARA_4.4.C.0033A	New Auburn South 132/11kV ZS, associated 132kV connections, 11kV load transfers and Auburn and Lidcombe ZS retirements	Auburn South zone substation and 132kV feeders 90F/3 and 90J/3
4	ARA_3.1A.0028A ARA_3.1B.0029A	New Alexandria STS, 132kV connections and replacement of Sydney Airport 33kV cables and reconnect Equinix to Alexandria STS	Alexandria subtransmission substation, 132kV feeder 9RG and 33kV customer feeders (TBA)
5	ARA_4.3A.0019 ARA_4.3A.0021	Dulwich Hill ZS 33kV feeder and 11kV switchgear replacement	New 11kV switchroom at Dulwich Hill zone substation and 33kV feeders 642, 646 and 647
6	ARA_4.4.A.0016	Replacement of 132kV feeder 900	132kV feeders 9P2, 9P8 and 9P9
7	ARA_4.3A.0001 ARA_4.3A.0007	New Strathfield South 132/11kV ZS, associated 132kV connections, 11kV load transfers and Enfield ZS retirement	Strathfield South zone substation
8	ARA_4.3A.0014	New Greenacre 132/11kV ZS, associated 132kV connections, 11kV load transfers and Greenacre Park ZS retirement	Greenacre zone substation
9	ARA_4.1.0008	New Rockdale 132/11kV ZS, associated 132kV connections, 11kV load transfers and Rockdale 33/11kV ZS retirement	Rockdale zone substation
10	ARA_4.1.0029	Peakhurst 33kV building and switchgear replacement	New 33kV switchroom at Peakhurst subtransmission substation
11	ARA_1.1.0024	Replacement of 132kV feeders 92G and 92J	132kV feeders 92G and 92J
12	ARA_1.1.0027	Replacement of 132kV feeders 92F and 90X	132kV feeders 92F and 90X
13	ARA_1.0013	New Munmorah STS and associated 132kV and 33kV connections	Munmorah subtransmission substation
14	ARA_5.5.0039A	Replacement of underground sections of 33kV feeders S08 and S10	33kV feeders S08 and S10

32. AUDIT REPORTS

32.1 Provide a Regulatory Audit report in the form of:

(a) a Special Purpose Financial Report in accordance with the requirements set out at Appendix C; and

(b) a Review report (for non-financial information) in accordance with the requirements set out at Appendix C.

Ausgrid has provided the following reports, consistent with section 32.1 and Appendix C of the RIN:

- SKM report
- Audit Office report

These reports have been provided as part of Ausgrid's response to the Reset RIN at Attachment C.

32.2 Provide all reports from the Auditor to Ausgrid's management regarding the audit review and/or auditors' opinions or assessment.

Ausgrid confirms it has provided all Auditor reports, consistent with the requirements in section 32.2 of the RIN.

33. BOARD RESOLUTION

33.1 Provide an extract from the board minutes or a resolution agreed to at a Ausgrid board meeting that confirms, to the best of the Board's information, knowledge and belief, the information provided in the response to paragraph 1.1 (being the information to be provided in the Microsoft Excel Workbooks attached at Appendix A is:

(a) for Actual Information, true and accurate; and

(b) where Ausgrid cannot provide Actual Information, Ausgrid's best estimate.

Ausgrid has provided a copy of the Board resolution in line with the above requirements at Attachment D.

34. TRANSITIONAL ISSUES

34.1 Provide information on existing potential transitional issues (expressly identified in the Rules or otherwise) which Ausgrid expects will have a material impact on it and should be considered by the AER in making its distribution determination. For each issue, set out the following information:

(a) the transitional issue;

(b) what has caused the transitional issue;

(c) how the transitional issue impacts on Ausgrid; and

(d) how Ausgrid considers the transitional issue could be addressed.

Ausgrid has addressed the issue of the appropriate transition to a rolling cost of debt in Chapter 7 and the approach to a "true up" alternative control services for the transitional year in Chapter 8.5 and Attachment 8.25 of the regulatory proposal.

At this stage Ausgrid has not identified any other transitional issues that should be considered by the AER in making it distribution determination. It may be that once the AER has made its draft determination that there will be transitional issues that need to be addressed. This is something that can be addressed in Ausgrid's response to the AER's draft proposal, either by way of submission or a revised proposal depending on the nature of the issue.

35. CONFIDENTIAL INFORMATION

35.1 This clause applies to any information Ausgrid provides:

(a) in response to Schedule 1;

(b) in a regulatory proposal, revenue proposal, proposed negotiating framework, proposed pricing methodology, access arrangement proposal or access arrangement for the forthcoming regulatory control period (a Proposal)

(c) in a revision or amendment to a Proposal; and

(d) in a submission Ausgrid makes regarding a Proposal or a revised or amended Proposal; (together, Ausgrid's Information).

We note that 35.1 does not require a response, but rather sets out instructions on what constitutes the relevant material.

35.2 If Ausgrid wishes to make a claim for confidentiality over any Ausgrid's Information, provide the details of that claim in accordance with the requirements of the AER's Distribution Confidentiality Guideline, as if it extended and applied to that claim for confidentiality.

In terms of 35.1(a) we note that Attachment Q Confidentiality Template to this RIN response provides a completed template for information we consider confidential in our RIN response. The documents we have provided as part of our RIN response comply with the requirements of the Distribution Confidentiality Guideline. The folder termed "RIN response Public" contains all the documents we have provided the AER as part of our response. In cases where a document contains confidential material, we have provided a public version of that document which blacks out the confidential section. These documents contain the filename "public" to signify that confidential material has been redacted. The folder termed "RIN response Confidential" also contains all the documents we have provided the AER as part of our response. However, in this folder if a document contains confidential information, we have provided a version which highlights in yellow shading the confidential section. These documents contain the filename "confidential" to signify that they contain confidential information that should not be disclosed.

In respect of 35.1(b) we note that our regulatory proposal contains a separate completed confidentiality template in accordance with the guidelines. Similar to our RIN response, the folders that contain our regulatory proposal documents contains all the documents we have submitted as part of our proposal. In cases where a document contains confidential material, we have provided a public version of that document which blacks out the confidential section. These documents contain the filename "public" to signify that confidential material has been redacted. The folder termed "Regulatory Proposal Confidential" also contains the entire suite of documents we have submitted as part of our proposal. In cases where a document contains confidential information, we have provided a confidential version which highlights in yellow shading the confidential section. These documents contain the filename "confidential" to signify that they contain confidential information that should not be disclosed.

We consider that the provision of information in relation to 35.1(c) and 35.1(d) are not applicable to this response, as revisions and submissions to the proposal will necessarily occur after we have provided this response on 31 May 2014, and therefore there is no such submission or proposal on which to make claims at the time of submitting this response. We also note that the AER's Confidentiality Guideline does not apply to submissions that we make to the AER as part of the regulatory determination process and that a RIN cannot operate to extend to requiring compliance with those guidelines with respect to submissions.

35.3 Provide any details of a claim for confidentiality in response to clause 1.2 at the same time as making the claim for confidentiality. Confirm, in writing, that Ausgrid consents to the AER disclosing all other of Ausgrid's Information on the AER website.

We have provided information as stated above in separate templates for our RIN response (including our basis of preparation) and our regulatory proposal respectively. For this reason we can confirm that we have complied with the AER's Confidentiality Guideline when making any claims for confidentiality over information provided as part of or accompanying its regulatory proposal. In relation to Ausgrid's consent to the AER disclosing all other Ausgrid's information, this is not a matter that can be required to be addressed as part of a response to a RIN.

Attachment A Ausgrid's Completed Regulatory Templates

Attachment B Ausgrid's Basis of Preparation

Attachment C Audit and Review Reports

Copies of:

- SKM Report
- NSW Audit Office Report

Attachment D Ausgrid's Board Resolution

Attachment E Table of Regulatory Proposal References

Attachment F Major Contracts Documentation

Confidential documentation relating to ten major contracts.

Attachment G Changing Maintenance Standards For Replacement Capital Expenditure

Attachment H Differences Between Ausgrid and AEMO Spatial Demand Forecast Methodologies

Attachment I Vegetation Management Compliance Audits

Attachment J Aon and Marsh Premium Estimates

Confidential information on Ausgrid's insurance premium estimates.

Attachment K Calculation of Self Insurance Allowance

Confidential copies of Ausgrid's calculation of self insurance allowances.

Attachment L Actuary Report on Self Insurance

Confidential actuary report prepared for Ausgrid on self insurance.

Attachment M Employee Benefits Actuary Reports

Confidential information on employee benefits actuary reports prepared for Ausgrid.

Attachment N Current Enterprise Bargaining Agreement

Attachment O Supporting Documents for Related Party Services

Copies of supporting documents for related party services, including confidential property valuation.

Attachment P Demand Management Policies

Attachment Q Confidentiality Templates