REGULATORY INFORMATION NOTICE UNDER DIVISION 4 OF PART 3 OF THE NATIONAL ELECTRICITY (NEW SOUTH WALES) LAW

ISSUED BY THE AUSTRALIAN ENERGY REGULATOR

Endeavour Energy

Response to Schedule 1 of the RIN

Submission date: 30 April 2018

Endeavour Energy

CONTENTS

PURPOSE

The AER requires Endeavour Energy to provide the information specified in Schedule 1 of the RIN, audited in accordance with Appendix C of the RIN.

This document is Endeavour Energy's response to the information sought in Schedule 1.

1. PROVIDE INFORMATION

1.1 Provide the information required in each regulatory template in the Microsoft Excel Workbook 1 – Regulatory determination, Workbook 2 – New category analysis, Workbook 5 - EBSS and Workbook 6 - CESS attached at Appendix A, completed in accordance with:

(a) this notice;

(b) the instructions in the relevant Microsoft Excel Workbook attached at Appendix A;

(c) the instructions in Appendix E;

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

(e) Endeavour Energy's cost allocation method.

The Microsoft Excel Workbooks have been completed and are provided at

- Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public;
- Endeavour Energy – RIN0.02 Final RIN Workbook 2 New CA – 30 April 2018 – Public;
- Endeavour Energy – RIN0.03 Final RIN Workbook 5 EBSS – 30 April 2018 – Public; and
- Endeavour Energy – RIN0.04 Final RIN Workbook 6 CESS – 30 April 2018 – Public.

The Workbooks have been completed in accordance with:

(a) the RIN;
(b) the instructions in the relevant Microsoft Excel Workbooks attached at Appendix A to the RIN;
(c) the instructions in Appendix E to the RIN;
(d) the service classifications set out in the framework and approach paper; and
(e) Endeavour Energy's approved Cost Allocation Method.

1.2 If:

(a) Endeavour Energy's cost allocation method has changed during the current regulatory control period, or

(b) Endeavour Energy's service classifications have changed from the current regulatory control period, or

(c) Endeavour Energy proposes to divert from the service classifications set out in the relevant framework and approach paper, or

(d) Endeavour Energy proposes to change its cost allocation method for the forthcoming regulatory control period;

such that there would be material changes to information previously submitted to the AER Endeavour Energy must use the regulatory templates in Workbook 3 – Recast category analysis and Workbook 4 – Recast economic benchmarking attached at Appendix A to submit revised historical information.

Endeavour Energy's Cost Allocation Method (CAM) has been clarified but not changed during the current regulatory period.

To rectify ambiguities identified by the AER, amendments to the existing CAM were made to clarify the allocation of overhead costs through more explicit allocations. The AER acknowledged that the CAM approved in November 2013 permitted the use of either causal or non-causal overhead allocators as identified by Endeavour Energy.

However, for clarity and transparency we agreed to amend our CAM to specify the causal allocators that would be used. We have provided our CAM as an attachment to our Regulatory Proposal (Endeavour Energy – 0.06 Cost Allocation Method – March 2018 – Public).

In addition:

- service classifications for the 2019-24 regulatory control period differ slightly from those for the current regulatory period. Endeavour Energy does not consider the changes to the ancillary network service grouping are material or require the restatement of previously submitted RIN data;

- we do not propose to divert from the service classifications set out in the AER's framework and approach paper; and

- we do not propose to change the CAM for the forthcoming regulatory control period.

For these reasons, Endeavour Energy is not required to submit recast historical information in Workbook 3 – Recast category analysis and Workbook 4 – Recast economic benchmarking.

1.3 For all information, other than forecast information, provide in accordance with this notice and the instructions in Appendix E, a basis of preparation demonstrating how Endeavour Energy 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:

(i) paragraph 1.2
(ii) paragraph 5.1(a)(ii)
(iii) paragraph 8.5
(iv) paragraph 13 (13.5 and 13.6)
(v) paragraph 15 (15.2 and 15.3)
(vi) paragraph 16 (16.2-16.7, 16.10)

A Basis of Preparation has been prepared and is provided as Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public. The Basis of Preparation demonstrates how Endeavour Energy complies 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:

(i) paragraph 1.2
(ii) paragraph 5.1(a)(ii)
(iii) paragraph 8.5
(iv) paragraph 13 (13.5 and 13.6)
(v) paragraph 15 (15.2 and 15.3)
(vi) paragraph 16 (16.2-16.7, 16.10)

1.4 Provide material used for the purposes of preparing the Regulatory Proposal.

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

All consultants' reports commissioned and relied upon in whole or in part in the preparation of the Regulatory Proposal are provided in the supporting attachments to our proposal and this RIN. Refer to Endeavour Energy – RIN1.02 Document Register – April 2018 – Public.

(b) all material assumptions relied upon;

Endeavour Energy has relied upon the following seven material assumptions in preparing the Regulatory Proposal:

<u>Assumption 1:</u> The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.

<u>Assumption 2:</u> The capital program has been prepared on the basis of the NSW Licence Conditions in place at the time forecasts are finalised.

<u>Assumption 3:</u> Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.

<u>Assumption 4:</u> Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts adopted for the Regulatory Proposal.

<u>Assumption 5:</u> Forecast internal labour costs and wage rate increases have been set based on the advice provided by an expert independent consultant BIS Oxford Economics provided to Endeavour Energy (on 29 September 2017).

<u>Assumption 6:</u> The opex year 2017-18 has been adopted as the efficient base year for deriving a forecast of recurrent opex.

<u>Assumption 7:</u> Endeavour Energy has engaged with stakeholders in developing its Regulatory Proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules and the AER's Customer Engagement Guideline.

(c) a table that references each response to a paragraph in this Schedule 1 and where it is provided in or as part of the Regulatory Proposal;

Endeavour Energy – RIN1.01 Response Reference List – April 2018 – Public references each response to a paragraph in Schedule 1 and where it is provided in or as part of the Regulatory Proposal.

(d) a table that references each document provided in or as part of the Regulatory Proposal and its relationship to other documents provided; and

Endeavour Energy has provided in table form, each document used in or as part of the Regulatory Proposal and its relationship to other documents provided. Refer to Endeavour Energy – RIN1.02 Document Register – April 2018 – Public.

(e) each document identified in paragraph 1.4(d) must be given a meaningful filename in the form:

Endeavour Energy – [Author] – [title] – [date] – [public/confidential], where:

(i) Author is the author of the file if not Endeavour Energy, for example a consultant or other third party;

(ii) Title provides a meaningful description of the content of document, with limited reliance on acronyms or cross references, for example "Appendix 1A" is not meaningful, but "Appendix 1A – Cost allocation method" is;

(iii) Date is a relevant date associated with the file, generally the date the document was created; and

(iv) Public/confidential identifies if the file in its entirety can be published (public); or if it contains any information which is the subject of a claim for confidentiality in accordance with paragraph 33 of this notice (confidential).

In referencing the documents as requested in 1.4(d), Endeavour Energy has provided each with a meaningful filename by adopting the **Endeavour Energy – [Author] – [title] – [date] – [public/confidential]** form.

1.5 Provide for each material assumption identified in the response to paragraph 1.4(b):

(a) its source or basis;
(b) if applicable, its quantum;
(c) whether and how the assumption has been applied and was taken into account; and
(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.

1. <u>The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.</u>

This assumption provides clarity that capex and opex forecasts have been prepared based on current ownership and legal structure and do not incorporate any impacts associated with a potential change of ownership.

Our organisational structure has also been important in providing strategic input into the objectives that have underscored the development of our capex and opex proposals. This includes our continued focus on customer affordability most recently promoted through our *Endeavour 2020* program. This has been instrumental in deriving cost savings that have been incorporated in our forecast capex and opex, and which have enabled us to meet our objectives of customer affordability while maintaining safety and reliability of the network.

2. <u>The capital program has been prepared on the basis of the NSW Licence Conditions in place at the time forecasts are finalised.</u>

This is a key assumption underpinning our asset management framework and forecasts of reliability and ICT compliance capex.

As a holder of a licence to operate a distribution system in NSW, Endeavour Energy is required to meet several ministerially imposed Licence Conditions primarily relating to supply reliability and network performance. These conditions are in place to ensure customers are provided with an adequate level of service and security. Meeting these obligations is a key assumption underpinning our forecasts of capacity, ICT and reliability compliance capex. Refer to Endeavour Energy – Minister for Resources, Energy and Utilities – 10.08 Licence Conditions – June 2017 – Public.

Our capex forecasts have been prepared on the basis of the NSW Licence Conditions in place at the time forecasts are finalised. We do not believe that there will be a change in Licence Conditions between the current and forthcoming regulatory control periods and we consider it is reasonable to conclude that current licence conditions will be in place for the entirety of the 2019-24 regulatory control period. Endeavour Energy's proposed reliability compliance capex comprises the required investments to comply with Schedule 3 (which relate to individual feeder reliability) of the licence conditions. Endeavour Energy's proposed IT and ICT capex includes the required investment to comply with the critical infrastructure licence conditions.

3. <u>Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.</u>

Endeavour Energy has long utilised a network planning framework that includes a process of risk-based project prioritisation. As there are a large number of competing constraints at any one time on our network, our prioritisation process ensures approval to undertake capital works is granted according to the risks placed on our network by current and impending constraints.

In conjunction with our gated governance process, our strategic asset management framework ensures our capital programs are targeted, justified and continuously monitored through to the post-delivery stage. Our prioritisation process also aims to identify prudent opportunities to defer or avoid capital expenditure based on an assessment of relative risk such that we could minimise our requirement for investment funding and better meet our goal of customer affordability.

Our risk-based prioritisation process can be broadly outlined as follows:

- in developing our expenditure plans, Endeavour Energy identified a full suite of projects and programs that would comprise the proposed expenditure portfolio. This was at a granular level;

- each project or program was assigned a risk ranking, based on a consistent methodology for assessing risk. Using the CASH risk prioritisation tool allowed us to objectively rank projects in a consistent way; and

- A board level review of the overall risk profile and the relationship between risk and different scenarios of expenditure identified the prudent level of capital investment which forms the basis of our expenditure forecast.

We consider that the outcome of prioritisation was reasonable, in that it reflected a prudent assessment of risks to achieve our objective of customer affordability. In this respect, the reasonableness can be demonstrated by the method used to rank relative risks of the program. This enabled us to prudently select programs that could be efficiently deferred.

Chapter 10 of our Regulatory Proposal and Endeavour Energy – 0.07 Expenditure Forecasting Methodology Statement – June 2017 – Public provide further details on our asset management framework and project prioritisation process.

4. <u>Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts adopted for the Regulatory Proposal.</u>

This is a key assumption underpinning our capacity related capex.

Peak demand forecasts set out the expected increase in peak demand on locations of our network, while customer connections record the increase in the number of residential and non-residential customers on our network.

In respect to our peak demand forecasts, we note that:

- Endeavour Energy's method relies on historical peak demand recorded at each zone areas, and this provides an indication of trends in demand growth at different points in the network. Importantly, our forecast process is capable of excluding spot loads from trend growth, considering new connections in the short term, the impacts of distributed energy resources and weather correcting; and

- in developing our capex forecasts for the 2019-24 period, we have applied our methodology using most recent available historic data.

Similarly customer connections forecasts have relied on historical estimates, and take into account evidence on changes from historical levels.

Information on our demand forecast methodology and outcomes can be found in Chapter 7 of our Regulatory Proposal. Further information of our forecasts and methodology can be found in:

- Endeavour Energy – Cutler Merz – 7.04 Review of Endeavour Energy Demand Forecasts and Basis for Spot Load Growth for 2019-2024 – April 2018 – Public;
- Endeavour Energy – NIEIR – 7.02 Post Modelling Adjustments for Demand Forecasts – June 2016 – Public;
- Endeavour Energy – NIEIR – 7.03 Economic Scenarios for the Endeavour Region 2017-2029 – September 2017 – Public;

- Endeavour Energy – 7.01 2018-2027 Summer Demand Forecast – August 2017 – Public;
- Endeavour Energy – RIN1.06 Branch Procedure NFB0010 Network Demand Forecasting – February 2016 – Public;
- Endeavour Energy – 10.09 Growth Strategy – February 2018 – Public;
- Endeavour Energy – 10.22 Augex Area Plans – April 2018 – Public;
- Endeavour Energy – 10.23 Augex Sample Business Cases FY19-24 – April 2018 – Public; and
- Endeavour Energy – 10.24 Augex Sample Business Cases FY14-19 – April 2018 – Public.

5. <u>Forecast internal labour costs and wage rate increases have been set based on the advice provided by an expert independent consultant BIS Oxford Economics provided to Endeavour Energy (on 29 September 2017).</u>

This assumption is material to the forecasts of undertaking capital works and operating activities in the 2019-24 period.

Real cost escalation refers to the movement in the price of labour relative to the Consumer Price Index (CPI). A positive value denotes that the price of labour is expected to increase above CPI. The impact of the value of real cost escalation enables us to estimate the likely cost of undertaking capital works or an opex activity in the year that the work is undertaken.

In deriving a value of real cost escalation for labour escalation, Endeavour Energy has adopted the forecast of labour escalation advised by BIS Oxford Economics (BIS). To ensure that the changes in labour costs appropriately reflect the skills required and the market factors driving the demand and supply of labour, BIS has provided expected changes in labour costs for the utilities sector in NSW.

We consider that our approach to adopt the values advised by BIS is reasonable for the following reasons:

- BIS Oxford Economics is an expert economic firm with the expertise to provide a reliable forecast, taking into account our industry;
- the method used by BIS (state based WPI of EGWWS) has been the approach the AER has used in recent regulatory determinations; and
- they are benchmark estimate that is below the amounts contained in our Enterprise Bargaining Agreement.

Our modelling has been audited to provide assurance that forecast labour price increases have been set based on the advice provided by BIS.

Further information on our labour cost escalation is in Chapter 11 of our Regulatory Proposal. The advice provided by BIS is contained in Endeavour Energy – BIS – 0.10 Real Cost Escalation Forecast – September 2017 – Public.

6. <u>The opex year 2017-18 has been adopted as the efficient base year for deriving a forecast of recurrent opex.</u>

This assumption is only relevant to our proposed forecast opex.

With the exception of debt raising costs, Endeavour Energy’s forecast opex is derived using the base year approach under which the actual operating expenditure of the regulatory year

2017-18 is used as the opening starting point upon which ‘change factors’ are applied to derive the future opex requirements for the 2019-24 period.

The base year ‘revealed cost’ base-step-trend method is commonly used by the DNSPs and is the AER’s preferred method to derive estimates of forecast opex. It is a reasonable method as our costs are largely recurrent. The 2017-18 base year will be the last available year of actual opex by the time the determination is finalised and is therefore the most current estimate of providing standard control services that are of a recurring nature.

By applying the base-step-trend methodology, 2017-18 base year opex is then adjusted to account for future changes in Endeavour Energy’s circumstances, operating environment, and changes in demand and cost inputs in arriving at a forecast opex. This is to ensure that all known factors affecting Endeavour Energy’s future opex requirements are appropriately accounted for. Notably, we have not proposed to include any step changes to account for new regulatory obligations or capex/opex trade-offs.

We note that the manner in which we have used 2017-18 data as a basis for forecasting is also fit for purpose and reasonable in our circumstances. For example:

- Removing non-recurrent end of year adjustments - Our base year opex also contains year-end adjustments to remove demand management innovation allowance, legal costs relating to the 2014-19 determination appeals process and movements in provisions opex. The removal of these costs is consistent with the excludable categories of opex for EBSS purposes specified by the AER in the 2014-19 determination and the requirements of the NEL.

Further information on why our approach to deriving forecast opex, including the manner in which we have applied 2017-18 data can be found in Chapter 11 of our Regulatory Proposal. The opex model is provided in Endeavour Energy – 11.01 Opex Model – April 2018 – Public.

7. <u>Endeavour Energy has engaged with stakeholders in developing its Regulatory Proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules and the AER’s Customer Engagement Guideline.</u>

Our engagement activities have influenced the development of our Regulatory Proposal.

The findings of our customer engagement activities support the key objectives of our Regulatory Proposal and resultant expenditure forecasts, and demonstrate that our proposal is reasonable.

Chapter 5 of our Regulatory Proposal provides further information on our customer engagement activities. We provide details of the activities we undertook in engaging customers and stakeholders on a range of issues in Endeavour Energy – 5.01 Customer & Stakeholder Engagement Activities and Findings – April 2018 – Public.

1.6 Provide reconciliation of the capital and operating expenditure forecasts provided in the regulatory templates to the proposed capital and operating allowances in the post-tax revenue model for the forthcoming regulatory control period.

Capital and operating expenditure forecasts provided in the regulatory templates have been reconciled to the proposed capital and operating allowances in the PTRM (Endeavour Energy – 0.04 Post-Tax Revenue Model – April 2018 – Public).

1.7 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.

Endeavour Energy's Regulatory Proposal does not vary or depart from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme.

With regard to the service target performance incentive scheme, a revised proposed scheme covering changes to the exclusion methodology for reliability is set out in Endeavour Energy – 10.07 STPIS Proposal & Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public.

2. CLASSIFICATION OF SERVICES

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

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

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

Each proposed service classification in Endeavour Energy's Regulatory Proposal does not depart from a service classification set out in the framework and approach paper.

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.

The proposed service classifications in Endeavour Energy's Regulatory Proposal do not depart from any of the service classifications set out in the framework and approach paper.

3. CONTROL MECHANISMS

3.1 For the forecast revenues that Endeavour Energy proposes 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.

Formulaic expressions for the basis of the control mechanisms for standard control services and for alternative control services are as per the AER's Final Framework and Approach (F&A) for the 2019-24 period[1].

The detailed explanations and justifications for each component that make up the formulaic expressions are as per those set out in the AER's F&A paper.

3.2 Also demonstrate:

(a) how Endeavour Energy considers the control mechanisms are compliant with the framework and approach paper; and

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

Endeavour Energy are proposing the control mechanisms contained in the AER's F&A for the 2019-24 period and therefore consider them to be compliant with the F&A.

Endeavour Energy considers the control mechanism for standard control services are also compliant with clause 6.2.6 and part C of Chapter 6 of the NER for the reasons set out in the AER's F&A for 2019-24.

[1] AER, Final Framework and approach for Ausgrid, Endeavour Energy and Essential Energy – Regulatory control period commencing 1 July 2019, July 2017, p. 52, 58

4. CAPITAL EXPENDITURE

4.1 Provide justification for Endeavour Energy's total forecast capex, including the following information:

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

The Rules states that Endeavour Energy's forecast capital expenditure must be the expenditure that it considers is needed to achieve each of the outcomes listed in clause 6.5.7(a), known as the 'capital expenditure objectives'. These objectives are[2]:

- meet or manage the expected demand for standard control services (objective 1);
- comply with all applicable regulatory obligations or requirements (objective 2);
- maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3); and
- maintain the safety of the distribution system through the supply of standard control services (objective 4).

Objective 1
Our capex program, in particular our augex forecast, has been developed to service the expected demand for network services over the regulatory control period. Our demand, customer connection and energy forecasts are described in detail in Chapter 7 of our Regulatory Proposal. Our demand forecasting process is detailed further in the following supporting attachments:

- Endeavour Energy – 7.01 2018-2027 Summer Demand Forecast – August 2017 – Public;
- Endeavour Energy – Cutler Merz – 7.04 Review of Demand Forecasts and Basis for Spot Load Growth for 2019-2024 – April 2018 – Public;
- Endeavour Energy – RIN1.06 Branch Procedure NFB0010 Network Demand Forecasting – February 2016 – Public; and
- Endeavour Energy – RIN1.07 Branch Workplace Instruction WFB0001 Network Demand Forecasting – April 2016 – Public.

We have developed our connection capex, capital contribution and augmentation forecasts based on the forecast demand and customer connection volumes for the 2019-24 period. The methodology and forecasts for these capex categories is outlined in Chapter 10 of our Regulatory Proposal and in more detail in the following supporting attachments:

- Endeavour Energy – 10.03 Capex Proposal (SAMP) – March 2018 – Public
- Endeavour Energy – 10.18 AER Augex Model – April 2018 – Public;
- Endeavour Energy – Nuttall – 10.25 Assessing the Endeavour Energy Augex Forecast – February 2018 – Public;

[2] See clause 6.5.6(a) for exact wording.

- Endeavour Energy – 10.26 Connections Capex Forecast – March 2018 – Public;
- Endeavour Energy – RIN1.21 Long-Term Customer Numbers – December 2017 – Confidential; and
- Endeavour Energy – RIN1.22 Short-Term Customer Numbers – December 2017 – Confidential.

Objective 2-4
As a DNSP in NSW we have a large number of obligations stemming from regulations, codes, guidelines, legislation and licence conditions. We provide a full listing of the obligations and requirements we must adhere to in regulatory template 7.3.

Our capex forecast is reflective of these obligations and most significantly impacted by the following obligations:

- **Our licence conditions:** our ministerially imposed licence conditions cover a range of asset management and performance requirements. These conditions impose planning standards, reliability performance outcomes, asset management practices, etc;

- **Technical regulator:** IPART is our technical regulator and requires substantially increased evidence that our organisation has sound and effective asset management strategies in place. It is now a requirement that the company’s Asset Management system and functions comply with the requirements of the international asset management standard ISO 55001 as a NSW Distribution Licence Condition. Endeavour Energy is working towards achieving certification to this standard;

- **Electricity Supply Act 1995 (NSW) and Electrical Supply Regulation 2014 (NSW):** these pieces of legislation impose obligations and standards relating to the construction, operation, repair, maintenance and safety of our network, arrangements for the connection of customers and the reliability and security of supply planning and compliance reporting;

- **Safety Codes, Standards and Guidelines:** There are numerous guidelines and standards that Endeavour Energy is required to adopt (in the absence of a better alternative) under legislation such as the Work Health and Safety Act or Electricity Supply Act 1995 (NSW). These include codes such as the National Electricity Network Safety code and various guidelines covering numerous areas of our operations including vegetation management, live line work, fire protection, working on cables, the installation of cables, application of auto-reclosers, design and maintenance of overhead distribution lines, inspection and preservation of wood poles, risk management etc;

- **Property:** in the course of our operations we own, acquire and access a large amount of land within our network area. These activities are governed by several property laws related to Aboriginal land rights, development of land for electrical infrastructure, creation of line easements, remediation of sites, general requirements relating to construction, operation, repair, maintenance and safety, etc; and

- **Environment and planning:** there are several requirements regarding environmental planning, assessment and consultation, handling hazardous materials, heritage considerations, land development requirements and other miscellaneous requirements.

These obligations have a direct consequence on our policies and practices and as a result our capex requirements. Our forecasting process provides assurance of our compliance through developing bottom-up forecasts for key categories of expenditure as a check that the total forecast derived from top-down models reasonably reflects the efficient cost that a prudent operator would need to achieve the opex objectives, based on a realistic expectation of demand forecast and cost inputs.

The supporting capex attachments to our Regulatory Proposal provide further detail of how we consider our obligations in developing capital plans and how we have sought to maintain the quality, reliability, safety and security of supply and the safety of our distribution system. In particular, Endeavour Energy's asset management plans including:

- Endeavour Energy – 10.01 Network Strategy – November 2017 – Public;
- Endeavour Energy – 10.02 Asset Management Strategy – April 2018 – Public;
- Endeavour Energy – 10.03 Capex Proposal (SAMP) – March 2018 – Public;
- Endeavour Energy – 10.04 Repex Proposal (SARP) – March 2018 – Public;
- Endeavour Energy – 10.14 Company Policy 9.2.1 Network Planning – May 2016 – Public;
- Endeavour Energy – 10.13 Company Policy 2.6 Investment Governance Framework – April 2016 – Public; and
- Endeavour Energy – 0.07 Expenditure Forecasting Methodology Statement – June 2017 – Public.

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

The AER must accept Endeavour Energy's forecast of required capital expenditure if it is satisfied that the total forecast capital expenditure reasonably reflects each of the capital expenditure criteria, being:

- the efficient costs of achieving the capital expenditure objectives;
- the costs that a prudent operator would require to achieve the capital expenditure objectives; and
- a realistic expectation of the demand forecast and costs inputs required to achieve the capital expenditure objectives.

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. Our investment strategies, principles, forecasting process and governance are described in Chapter 10 of our Regulatory Proposal and Endeavour Energy – 0.07 Expenditure Forecasting Methodology Statement – June 2017 – Public. Broadly, we use the AER's top down models as validated by detailed, bottom-up analysis to derive an estimate of our capital requirements which is then subject to a probabilistic, risk-based prioritisation process and robust governance framework.

In terms of demonstrating that our forecasting process is efficient and prudent, these documents provide evidence to show that:

- we have effective policies and procedures to inform our expenditure decisions and our planning processes;

- our governance processes ensure that expenditure decisions are appropriately delegated and have effective financial controls;

- we have used a fit for purpose forecasting method which ensures there is no overlap or gap in our expenditure requirements, and uses appropriate methods for identifying investment on different parts of our network and network elements; and

- we have a consistent and appropriate method for identifying investment need that takes into account our circumstances, and a rigorous approach for selecting of the most efficient option to address the need.

A key element of our forecasts process is the use of realistic expectation of the demand forecasts and costs inputs, consistent with the capex criteria in the NER. Endeavour Energy's planning process has incorporated accurate and up to date peak demand forecasts as part of the key inputs into developing capital plans. Endeavour Energy records peak demand at each of its 164 zone substation areas, and this provides an indication of trends in demand growth at different points in the network. Importantly, Endeavour Energy's forecast process is capable of excluding spot loads from trend growth, considering new connections in the short term, incorporating the impact of distributed energy resources and energy efficiency requirements and weather correcting.

In terms of cost estimates, we have used 'fit for purpose' methodologies to derive the costs of undertaking projects or programs of work in each capital plan. Our methodologies take into account historical experience, the specific nature of the program of work, and potential efficiencies that may arise. Our cost estimates have also taken into account expert opinion from economic forecasters on real cost escalation over the 2014-19 period.

The prudency and efficiency of our capex forecast is addressed further in our response to paragraph (c) below.

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

Endeavour Energy's total forecast capex accounts for each of the capex factors. In relation to the factors that relate to the prudency of our forecast (the forecasting process):

- we have considered the substitution possibilities between operating and capital expenditure in developing our forecast expenditure (capex factor 7). A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions.

  The most significant interaction between capex and opex relates to replacement capex and maintenance opex. Where assets are replaced more frequently and/or proactively this is likely to reduce maintenance costs as assets are less likely to fail or require as frequent servicing (and vice versa).

  In order to maintain existing service and reliability levels we have increased our replacement capex forecast compared to recent levels (2015-16 and 2016-17) due to our ageing asset base. Our opex forecast is based on existing maintenance practices, specifically the 2017-18 base year which is reflective of an increase in replacement capex to a more sustainable long-term level. Any amendments to our replacement program are likely to have an impact on our required maintenance opex (although the relationship is difficult to quantify).

An additional interaction between capex and opex relates to non-network solutions. This is because there are occasionally circumstances whereby a network constraint can be addressed by non-capital (i.e. opex) solutions like demand management. Our forecast capital program is reflective of the benefits and outcomes of our non-network programs to date. Over the 2019-24 period we will incur additional opex where it is efficient to do so to defer capex (typically determined as part of a RIT-D process) and in consideration of the relevant incentive schemes;

- Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives (capex factor 10). We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities. The savings from demand management initiatives have been incorporated into our capex forecasts;

- we have considered the relative prices of operating and capital inputs (capex factor 6). As noted above we have sought to assess all feasible options when addressing a need including opex and capex options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation;

- our forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers (capex factor 5A). We engaged customers on a range of issues, particular through our capex 'deep dive' sessions. The findings from our customer engagement support the basis of our proposed total capex including in relation to affordability, maintaining current levels of safety and reliability and investing in and trialling new technologies to support customer choice and control in the future;

- Endeavour Energy's forecast method considered whether any projects or programs of expenditure should be identified as contingent projects, and therefore excluded from the total forecast capex for standard control services (capex factor 9A). We have identified a project that meets the criteria set out in 6.6A.1 of the Rules, see section 10.6 of our Regulatory Proposal for further detail;

- At the time of submitting our Regulatory Proposal final project assessment reports are available for the following projects included in our 2019-24 forecast capex (capex factor 11):

  - Stage 2 of South Marsden ($9.6 million in 2019-24) with final project assessment report issued April 2018;
  - North Leppington ($3.2 million in 2019-24) with final project assessment report issued in October 2016; and
  - A draft project assessment report for South Leppington Stage 2 ($14 million in 2019-24) has also been recently published.

We have addressed the remaining capex factors that we consider may represent partial indicators of the efficient level of capex. In relation to actual and expected capital during any preceding regulatory control periods (capex factor 5), we consider there are two primary considerations that provide a partial check on the total forecast proposed:

- we have identified key variations to forecast capex in the 2014-19 period, and consider that these have been taken into account when developing forecasts in the next period. See section 10.4 of the Regulatory Proposal for further details; and

- our forecast capex for 2019-24 is more than the 2014-19 period, and can be explained by key changes in our circumstances. In particular the higher capex is driven by the priority growth areas in our network area which constitute the biggest coordinated land release in the state's history. Additionally, there is an increasing need to replace ageing assets in order to maintain the safety and reliability of our network. Also, the 2014-19 capex was impacted by the investment uncertainty created by the 2014-19 re-determination process and Endeavour Energy lease transaction process.

We note that previous expenditure analysis should be viewed in conjunction with whether the forecast is consistent with any incentive schemes that apply to the DNSP (capex factor 8). During the 2014-19 period the CESS applied to capex for the first time providing a strong incentive to prudently and efficiently reduce capex relative to the AER's allowance. Endeavour Energy's actual capex in the 2014-19 period was lower than forecast. In this respect, customers will benefit from reductions to the RAB which lowered prices when transitioning to the new period.

The incentive regime has played a complementary role in the speed of our reform process, including re-orientation of strategies and planning processes towards meeting our goal of customer affordability. In this way, we consider that the AER can place weight on the efficiency of the forecasts for the 2019-24 period, providing a partial indication on the efficiency of our total capex.

The AER must also consider the most recent annual benchmarking report and the benchmark capital/operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (capex factor 4). The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data.

We note that the AER have released an Annual Benchmarking Report since 2014. This report primarily focusses on measures relating to opex. In addition to this report, the AER also relied on econometric benchmarking techniques in assessing opex as part of the 2014-19 determination process. In addition to this, we have continued to rely significantly on the AER's repex and augex models in determining an efficient level of capex. Based on this analysis we note:

- AER capex related measures: our performance has been improving against the AER's capex related measures contained in the ABR or 2014-19 determination. These benchmarks focus on overall capex or RAB and Endeavour Energy has generally been improving relative to its closest apparent peer Energex;

- Augex: Our forecast augmentation program is based on our detailed demand forecasts, capacity and utilisation information and development activity expectations and customer connection forecasts. We test this forecast using the AER's Augex model. This model compares utilisation thresholds with forecast of maximum demand to identify parts of the network which require augmentation. The model then uses capacity factors to determine volumes and historical unit costs to derive forecasts. We consider this model has limitations in its applicability to greenfield growth related augmentation and is therefore more suitably used to identify general trends in asset utilisation and any potential outliers in the augex program. Our forecast augmentation capex for the 2019-24 period is significantly lower than the forecast produced by the AER's augex model. Refer to Endeavour Energy – Nuttall Consulting – 10.25 Assessing the Endeavour Energy Augex Forecast – February 2018 – Public for further details;

- Repex: Replacement capex is the largest category of capex. We utilise detailed asset information and our expert judgment in developing a replacement program that replaces assets at a sustainable rate over the long-term. The primary test of this forecast is the AER's repex model which we consider is a benchmarking tool. The repex model predicts the likely asset replacement volumes and expenditure based on the number and age of assets in service, their assumed replacement age and historical unit costs. When set to the previously applied calibration our forecast replacement capex for the 2019-24 period is lower than the forecast produced by the AER's repex model. Refer to:

    - Endeavour Energy – Nuttall – 10.21 Assessing Endeavour Energy's Replacement Forecast – February 2018 – Public; and
    - Endeavour Energy – 10.17 AER Repex Model – April 2018 – Public.

- Overall, our analysis of benchmarking tools suggests that Endeavour Energy is trending in a positive direction and benchmarks favourably when key environmental factors are appropriately accounted for.

The final factor we have considered as a partial indicator of efficiency is the extent the capital expenditure forecast is preferable to arrangements with another person that do not reflect arm's length terms (capex factor 9). We confirm that our forecast capex for 2014-19 does not include any arrangement with any other person that do not reflect arm's length terms.

(d) an explanation of how the plans, policies, procedures and regulatory obligations or requirements identified in Workbook 1 – Regulatory determination, regulatory templates 7.1 and 7.3 have been used to develop forecast capex; and

Refer to regulatory templates 7.1 and 7.3, sections 10.3 and 10.5 of our Regulatory Proposal and supporting attachments:

- Endeavour Energy – 10.01 Network Strategy – April 2018 – Public;
- Endeavour Energy – 10.02 Asset Management Strategy – April 2018 – Public;
- Endeavour Energy – 10.03 Capex Proposal (SAMP) – March 2018 – Public;
- Endeavour Energy – 10.04 Repex Proposal (SARP) – March 2018 – Public;
- Endeavour Energy – 10.14 Company Policy 9.2.1 Network Planning – May 2016 – Public;
- Endeavour Energy – 10.07 STPIS Proposal and Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public;

- Endeavour Energy – 10.11 Transmission Network Planning Review 2017-2026 – October 2017 – Public;
- Endeavour Energy – 10.27 ICT Investment Plan – February 2018 – Confidential;
- Endeavour Energy – 10.29 Fleet Capex Plan – March 2018 – Confidential; and
- Endeavour Energy – 10.30 Buildings, Property and other Non-network Capex Plan – March 2018 – Public.

(e) an explanation of how each response provided to paragraph 4.1 (a) to (d) is reflected in any increase or decrease in expenditures or volumes, particularly between the current and forthcoming regulatory control periods, provided in Workbook 1 – Regulatory determination, regulatory templates 2.1 to 2.11.

Increases and decreases in volumes and expenditures, particularly between the current and forthcoming regulatory control periods are discussed in our Regulatory Proposal and supporting documents, in particular the asset management plans detailed in our response to question 4.1 (d) above and sections 10.4 and 10.5 of our Regulatory Proposal and attachments supporting our capital expenditure forecast.

4.2 Provide the model(s) and methodology Endeavour Energy used to develop its total forecast capex, including:

(a) A description of how Endeavour Energy prepared the forecast capex, including:

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

The process for developing capex forecasts is described in Endeavour Energy - 0.07 Expenditure Forecasting Methodology Statement – June 2017 – Public and Chapter 10 of our Regulatory Proposal. Endeavour Energy takes a systematic approach in its development of forecast capex programs and the process followed for the regulatory period forecast is no different to normal budgetary, planning and governance processes.

Future capex programs are contained within the Strategic Asset Management Plan (Endeavour Energy – 10.03 Capex Proposal (SAMP) – March 2018 – Public), which identifies future capital expenditure needs over a forward ten (10) year period. Individual plans are developed in the key expenditure areas based on asset need. The SAMP uses a risk-based project prioritisation framework to integrate and prioritise these plans into an overall capital and operating expenditure program with appropriate input from relevant stakeholders. The plan is updated on an annual basis and contains proposed costs of all future capex.

In principle, capex forecasts for individual programs are produced by identifying specific network needs and the location/quantity. An appropriate unit rate, normally based on past experience, is then applied to determine an expenditure forecast.

A bottom up approach is taken to producing each of the programs in the capex forecast. There is no one single model that encompasses all capital expenditure forecasts. There are a large number of discrete models which forecast individual programs or components within programs. The resulting program is tested and amended based on top-down modelling challenges including our VDA model and the AER's repex and augex models.

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

The process for developing capex forecasts is described in Endeavour Energy - 0.07 Expenditure Forecasting Methodology Statement – June 2017 – Public. Endeavour Energy has a governance framework in place which results in capex forecasts being reviewed multiple times before final approval. This includes review by line management initially, the Endeavour Energy Investment Governance Committee and eventually the Board.

(ii) if and how Endeavour Energy considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.

See Chapter 5 and sections 10.2 and 10.5 of our Regulatory Proposal for how we have considered customer pricing impacts in developing our overall capex forecast. To summarise, we reduced our capex forecast below our bottom-up condition based forecasts and below top-down model forecasts to limit the pricing impacts of our capital program. As explained in Chapter 10 of our Regulatory Proposal, we have reduced our capex forecast and expect to maintain the quality and safety of our services through delivery efficiencies and improved asset condition information leading to better asset management decisions.

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

Relevant documents that support the capital works strategies for Endeavour Energy are provided with this submission. Endeavour Energy has provided a list of supporting documents that accompany Chapter 10 of our Regulatory Proposal.

(c) all calculations that demonstrate how data from the source material has been manipulated or transformed to generate data provided in the regulatory templates in Workbook 1 – Regulatory determination.

Details of data manipulation for each of the regulatory templates are provided in the Bases of Preparation documents that form part of the regulatory submission. We have also provided a listing of our capital programs and projects (our "PIP" listing) with how each project maps to the RIN categories. Refer to Endeavour Energy – 10.16 Capex Listing (PIP) – April 2018 – Public.

4.3 Identify which items of Endeavour Energy's forecast capex are:

(a) derived directly from competitive tender processes;

Forecast capex for those major projects that are in flight (i.e. commenced within the current RCP and scheduled for completion within the next RCP) have been derived directly from a competitive tender process. For the remainder, the historical unit rates used to develop our capex forecast do reflect our extensive use of external resources through our blended delivery model and new Alliance Partnership.

(b) based upon competitive tender processes for similar projects;

As noted above historical project costs are used to forecast future project expenditure. Typical costs are based past projects which typically have a proportion of costs that are subject to competitive tender process.

(c) based upon estimates obtained from contractors or manufacturers;

No part of the forecast Capex is derived directly from estimates obtained from contractors or manufacturers.

(d) based upon independent benchmarks;

No part of the forecast Capex is based upon independent benchmarks.

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

In relation to project estimating, there are several scenarios that need to be considered as follows:

Major Projects (including Major Renewal Projects)
At the initial inception stage of a project (Gate 1), i.e. after the identification of a network need and the translation of that need into the SAMP, a historical estimate based on past projects of similar content is generally used at that stage. As part of our standard planning process, we review opportunities for non-network options including demand management to address the identified constraint. If these initiatives cannot address the network need, a Network Investigation Options (NIO) team is formed to identify the possible and most feasible network option to address the constraint. Where the impact of a constraint is localised, business cases are often developed in lieu of a NIO. This involves the preparation towards a second stage approval (Gate 2) that contains a preliminary "bottom up" estimate based on what is a fairly detailed understanding of the project needs for the identified preferred option. These costs are prepared using current prices for major equipment based on existing contracts where these exist.

A "first stage" approval is then obtained that allows detailed design on the preferred option to proceed. This process allows the project estimate to be refined using the most up to date plant prices and to assess and quantify any further project requirements. Once this detailed estimate is produced, second and third stage approvals are sought for the final cost amount. Note that if the regular annual review of the SAMP occurs during the time span of this development/approval process, then the costs as understood at this stage are included in the updated SAMP.

Distribution Works
Estimates for all distribution works are based on a unit rate principle for proposed works that are identified within the DWP, including for general HV works, overloaded feeders and those works associated with major projects. This unit rate system comprises a comprehensive list of activities and is updated on an annual basis through consultation with Regional staff as material costs and/or work method practices change. Further detailed estimates are produced post-detailed design in the Regions for final approval of the works.

Renewal Programs
Again, estimates in this area are based on an understanding of unit rates for each specific activity. Once a renewal volume is understood and identified in the SARP, then costs can be determined for the total program using the current unit rates. Similar

to the distribution area, the rates are updated on an as needs basis through consultation with Regional staff as material costs and/or work method practices change.

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

The key area of uncertainty in the capex forecast arises from projects proposed to provide capacity to service greenfield development. A number of projects have been proposed based on information from developers and the Department of Planning. The rationale for these is found in the various greenfield development business cases (Endeavour Energy – 10.23 Augex Sample Business Cases FY19-24 – April 2018 – Public).

The expenditure proposed for each of these projects reflects the probability that is assigned to each individual development proceeding. Total expenditure proposed for these projects in total is expected to be sufficient to establish the infrastructure for those developments that do proceed.

4.4 Provide all documents which were materially relied upon and relate to the deliverability of forecast capex and explain the proposed deliverability.

We are in a strong position to deliver the required network investment during the 2019-24 regulatory period.

Following the lease transaction, our new management team identified opportunities for our business to derive further capital delivery efficiencies. Two new delivery models are being developed to address our capital program.

- Major Projects Unit (MPU): contracted delivery of the major capital works program, including new zone substation construction, major plant replacements, sub-transmission feeder construction and related civil programs. A small number of contractors will be engaged under a new Collaborative Framework Agreement (CFA) for the period 2017-18 to 2023-24; and

- Alliance partnership: a non-incorporated joint venture for delivery of low value, high volume programs. This allows our external partners to work seamlessly alongside our internal employees as a combined and flexible workforce.

We expect our new Major Projects Unit and Alliance Partnership will enable us to meet our obligations to facilitate development growth in our network area and deliver reliability outcomes from a resilient network as expected by our customers. Other expected benefits from this model include:

- lower administration costs through less contracts, variations and scope creep;
- improved access to broader and different skills and capabilities;
- reduced costs through sharing of depots, equipment and skills with external contractors; and
- fast and flexible resourcing with more consistent standards of work.

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

(a) key drivers for expenditure;

The capex categories identified in the regulatory templates are, by definition:

- Augmentation Capital Expenditure;
- Connections Capital Expenditure; and
- Replacement Capital Expenditure.

See section 10.5 of our Regulatory Proposal for an explanation of the drivers for each category of expenditure and Endeavour Energy – 10.03 Capex Proposal (SAMP) – March 2018 – Public for further details.

(b) an explanation of how expenditure is distinguished between:

(i) greenfield driven and reinforcement driven augmentation capex;

Classification of greenfield versus reinforcement driven Augex is made for each project or program on a case by case basis.

The principles which guide the classification as greenfield are:

- the project is required to service large scale greenfield residential or industrial release areas;
- the existing infrastructure prior to development within these service areas are of a rural standard; and
- The development area is a significant distance from existing urban standard zone substations.

The principles which guide classification as reinforcement are:

- the project is required to service predominately infill development in existing urban areas (eg. increasing density); and
- the project is triggered by incremental load increase on existing assets within established service areas.

(ii) connections expenditure and augmentation capex;

In the relevant regulatory templates, (eg table 2.4.6 in Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public) expenditures are divided into “customer initiated” and “NSP initiated”. While both of these categories are demand driven, the former can be directly associated with specific greenfield residential or industrial development, while the latter is as a result of a need to reinforce the higher tiers of the network due to organic load growth. Endeavour Energy assigns a primary driver to each major project and program in its capital expenditure forecast. This distinguishes between “Network Connection” driven expenditure versus existing capacity constraints that have arisen over time in a gradual manner.

(iii) replacement capex driven by condition and asset replacements driven by other drivers (e.g. the need for greenfield or reinforcement driven augmentation capex); and

Endeavour Energy adopts a range of approaches for identifying assets that are candidates for renewal, ranging from simple inspection and condition-based maintenance regimes through to detailed technical analysis of key asset indicators.

Using these approaches outlined above, short-term renewal programs are established based on available data supplemented with expert knowledge of the imminent end-of-life of the assets in question. These short-term programs are integrated into longer term renewal programs to provide accurate expenditure projections and enable the efficient integration of renewal, growth-driven and other asset management activities. Replacement capex is generally non-demand driven. However, a coordinated approach is taken whereby when a replacement need is identified, any augmentation needs are taken into account, and if these augmentation needs are considered to be the dominant driver for the augmentation, then the project will become a capacity driven project.

(iv) any other capex category or opex category where Endeavour Energy considers that there is reasonable scope for ambiguity in categorisation.

Endeavour Energy has no categories when the categorisation is considered ambiguous. However, in the absence of a ‘balancing item’ several items of expenditure previously captured within this category have been allocated as to Repex:

- Technology;
- LV Planning;
- Metering and Relays;
- Power Quality; and
- Reliability.

5. REPLACEMENT CAPITAL EXPENDITURE MODELLING

5.1 In relation to information provided in Workbook 1 – Regulatory determination, regulatory template 2.2 and with respect to the AER's repex model, provide:

(a) For individual asset categories in each asset group set out in the regulatory templates, provide in a separate document:

(i) a description of the asset category, including:

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

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

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

(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.

Refer to Endeavour Energy – RIN1.17 Replacement Capex Modelling – March 2018 – Public.

Notes:

- We have no reported expenditure in the reset RIN for the asset categories shaded;
- "Assets included" – only assets/programs/works with a material impact are noted; and
- The "Replacement cost" calculation is based on expenditure and units and will give the unit rates. All other equipment included in the replacement cost has been converted to "equivalent units" (eg – in the Poles asset group, pole hardware replacement costs have been converted into an equivalent number of pole replacements).

(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;

97% of repex expenditure in the current period is due to asset condition.

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

A limited volume of replacements address safety risks which are not wholly attributed to the condition of the assets but a combination of condition and the design of the asset, with design of the asset being the principle contributor to the risk. An example is the 11kV bulk oil circuit breaker replacement programs in the Switchgear asset group where the driver is the safety issues due to the risk of an oil circuit breaker failing to clear a fault and exploding and causing a fire in a zone substation control building. This risk is being addressed by programs TS173 and TS700 which account for $14.3M or 2.3% of the renewal expenditure in the current RCP.

A further repex driver is reliability. The battery duplication program TS177 addresses a specific reliability risk inherent in the design of zone substation assets and accounts for $4.0M or 0.6% of renewal expenditure in the current period.

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

Endeavour Energy does not have data that details the proportion of asset replacements due to augmentation works and hence cannot proportion the volumes as outlined.

However, it is estimated that there is a 5% bleed between growth driven augmentation investment and renewal investment.

This expenditure is excluded from the repex proposal.

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

Nil.

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

Note – only the current and forthcoming RCPs have been discussed.

(i) rules, codes, licence conditions, statutory requirements;

Nil material change.

(ii) internal planning and asset management approaches;

Digression from an asset age profile and condition based investment trend is evident during the current FY15 - FY19 regulatory period. This has been due to the temporary impacts of the lease transaction in the earlier years of this period and resulted in a deferral of a number of planned capital investments. This approach was undertaken in order to provide the new majority shareholder flexibility to review and undertake investments that aligned to their preferred asset management practices. Following the completion of the transaction project, investment has increased over the remaining years of FY15 - FY19 regulatory period to the extent possible without incurring a penalty under the Capital Expenditure Sharing Scheme (CESS). The repex proposal for the forthcoming regulatory period returns to a more normal trend commensurate with the condition and age profile of the asset base.

(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;

There are a range of condition trends and risk factors which affect the need for renewal expenditure in the next regulatory period. These are detailed on an asset group and individual program basis in (vii) below.

(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 paragraphs 11.3 and 11.8);

Nil material influence.

(v) technology/solutions to address needs, covering:

(A) network; and

An example of technology being used to improve asset condition assessment and renewal planning is the use of neutral integrity meters to identify failing sections of low voltage CONSAC cable. However, this application has resulted in an increase in cable being found to be faulty and being replaced. Refer (vii) below for further detail.

(B) non-network.

No material influence to date. The RIT-D process may have some impact in time but to date all renewal projects which have been subject to the RIT-D have not resulted in a viable non-network solution to address the renewal need.

(vi) any other significant matters.

Nil.

(vii) Identify and provide information or documentation to justify and support any responses to paragraph 5.1(b) (i)-(vi).

The information provided in response to paragraph 5.1(b) above should at least distinguish between the asset categories listed in Workbook 1 – Regulatory determination, regulatory template 2.2.

The following sections provide detail of the particular projects and programs that account for any significant increases in proposed expenditure from the current regulatory period to the next within the asset groups where there is a material increase. The asset groups discussed include:

- Transformers;
- Poles;
- Switchgear;
- Underground cables; and

- Other - Substation civil and ancillaries.

Asset Groups with increases from current RCP

Transformers

Item	Current Period (FY15 to FY19; $M)	Forecast Period (FY20 to FY24; $M)	Change ($M)
Distribution transformers	22.1	32.9	10.8
Power transformers	31.2	84.6	53.4
Transformers group total	**53.3**	**117.5**	**64.2**

Increases in expenditure are being driven by:

- Ongoing deterioration in the condition of the fleet of transformers;
- Deferral of expenditure during the last period is now required to be redressed in forthcoming period; and
- Ongoing increases expected in line with the condition profile of the transformers and the continued deterioration of the older units over time.

Poles

Item	Current Period (FY15 to FY19; $M)	Forecast Period (FY20 to FY24; $M)	Change ($M)
Pole top hardware (DS418, DS421, TM033)	3.0	44.0	41.0
Steel tower replacement (TM015)	1.6	18.4	16.8
Transmission poles (TM012)	14.5	19.8	5.3
Distribution poles (DS005)	60.1	64.4	4.3
Other (Line replacements, tower footing and earthing refurbishment, tower painting and asbestos paint removal)	14.1	12.9	-1.2
Poles group total	**93.3**	**159.5**	**66.2**

There have been substantial changes in the range of programs which make up the “poles” asset group between the current 15 – 19 RCP and the forthcoming 20 – 24 RCP.

The most significant change is the commencement of a new refurbishment program to address defective pole top hardware with costs captured in the “pole replacement” category (rather than obscured by other maintenance works costs). These programs account for 54% of the increase in expenditure from the current RCP to the next. A further 22% is accounted for by a new program to replace 132kV steel towers which have reached the end of their life due to corrosion damage.

Further, the actual volume of replacement/reinstatement of poles is forecast to increase by 12% from the current period to the next due to the age profile of the fleet of poles.

Switchgear

Item	Current Period (FY15 to FY19; $M)	Forecast Period (FY20 to FY24; $M)	Change ($M)
11kV MD4 replacement (DS307)	7.5	35.9	28.4
Other distribution	24.9	24.7	-0.2
Total distribution	**32.4**	**60.6**	**28.2**
132, 66 and 33kV circuit breaker replacement (TS004, TS005, TS055)	9.1	8.7	-0.4
Zone substation 11kV oil CBs replacement (TS007, TS173, TS700)	14.3	35.0	20.7
Zone and transmission substation renewal	23.2	9.3	-13.9
Total transmission	**46.5**	**52.9**	**6.4**
Switchgear group total	**79.0**	**113.6**	**34.6**

The two significant increases are due to the MD4 distribution switchgear replacement program DS307 and the 11kV oil circuit breaker replacement programs TS173 and TS700.

1. MD4 switchgear

Endeavour Energy currently has 5,300 installations of MD4 cast resin switchgear in padmount and indoor substations throughout its network. As it ages the switchgear is prone to failure due to discharge over the surface of the resin. The R4M compound terminations commonly used for the 11kV terminations onto the MD4 switchgear can also lose compound resulting in discharge and failure.

Failures of MD4 are often explosive in nature posing a risk to workers or the public who may be in the vicinity of the installation at the time and causing an interruption to the supply to all of the customers supplied by the same 11kV feeder.

MD4 switchgear is inspected and tested for partial discharge every three years in accordance with substation maintenance instruction SMI101 - Minimum requirements for maintenance of distribution equipment.

However, a recent review of the inspection and partial discharge (PD) testing processes was carried out due to the observed increase in the failure rate of 11kV MD4 switchgear in padmount substations. As a result, technical bulletin TB-0236 was released in June 2017 outlining new test limits and defect prioritisation methodology to improve the outcomes of the PD testing process. These changes have resulted in a significant uplift in the replacement of MD4 units assessed as being in poor condition and at risk of failure.

2. Zone substation 11kV oil circuit breakers

Endeavour Energy currently has 667 11kV oil circuit breakers in service in zone substation control buildings throughout its network. The Company has a strategy of replacing all of these breakers with vacuum circuit breakers to address the safety and reliability risks associated with their catastrophic failure with the potential to initiate an arc, explosion and oil fire in the substation.
There are three methods being used to address this risk:

- Program TS173 including the replacement of just the oil circuit breaker trucks with vacuum trucks; or
- Program TS700 which includes the complete replacement of the 11kV switchboard with a new switchboard with vacuum circuit breakers; or
- The replacement of the 11kV switchboard with a new switchboard in a new control building as part of a major renewal project.

A recent cost benefit assessment confirmed that the safety risk cost of doing nothing was comparable to or exceeded the cost of replacing the switchgear with vacuum equipment confirming the need for the program(s). It further showed that older switchboards should be completely replaced under program TS700 whilst newer switchboards should have their usable life extended by replacement of just the circuit breaker trucks with vacuum units under program TS173.
Currently all of the funding for 11kV oil circuit breaker replacement in the FY20 – 24 regulatory period is under program TS700.

In situations where there are significant other renewal needs in the substation, a major project to replace the entire control building including the 11kV switchgear may be developed. These projects have their own unique project number and their circuit breaker replacements are excluded from programs TS173 and TS700.

Aged paper insulated cables present a risk of failing at the termination onto the switchgear or failing due to damage during the disconnection and relocation works required during switchboard replacement. The risk of termination failure is growing as the paper cables in the network deteriorate due to age and exposure to heat. Two paper cable terminations failed at Blaxland ZS in January 2017 resulting in a substation fire which caused extended outages to customers and damage to the 11kV switchboard which required the replacement of the entire switchboard.

To address this risk, the proposed approach includes replacing paper insulated feeder cables from the zone substation out to the first termination or to a joint in the street when the 11kV switchboard is replaced. XLPE insulated cables do not present the same risks and may be re-terminated onto the new switchboard where they are in service.

This program of replacement of oil 11kV circuit breakers commenced in the middle of the current regulatory period and is currently increasing in volume to address the risks posed by the switchgear in a reasonable timeframe (nominally by FY27).

Refer to the attached (draft) *11kV bulk oil circuit breaker renewal plan* for further information.

Underground cables

Item	Current Period (FY15 to FY19; $M)	Forecast Period (FY20 to FY24; $M)	Change ($M)
LV CONSAC (DS006)	24.4	46.5	22.1
Other LV cable replacement (DS014, DS415)	0.6	13.4	12.8
33kV and 66kV gas and oil filled cable replacement (TM014)	7.2	0.7	-6.5
Other cable replacement works	15.3	5.0	-10.3
Underground cables group total	**47.5**	**65.6**	**18.1**

An increase in the rate of replacement of CONSAC cable accounts for the majority of the increase in expenditure observed in the Underground cables asset group with the remainder accounted for by other LV cables and mains replacements.

LV CONSAC distribution mains were installed in residential areas across Endeavour Energy's Network up until 1975 and in the Campbelltown area until 1981. A total of approximately 700km was installed.

CONSAC can suffer from a number of failure modes including failures of joints in pillars and streetlight columns, in-ground joints and failure of the concentric aluminium neutral conductor. The principal risk presented by CONSAC failure is shock hazards to the public and workers due to the loss of the neutral connection and as a result the DS006 – LV CONSAC cable replacement has been in place for a number of years.

Approximately 30% of CONSAC in Endeavour Energy's network has been replaced with XLPE cable leaving approximately 500kms of CONSAC remaining in service.

Neutral Integrity (NI) monitoring devices have recently been installed on customer's switchboards that are supplied by LV CONSAC cable. The data from these devices, which provide over 95% coverage of CONSAC feeders, is now assisting the identification of sections of CONSAC which are deteriorating and at risk of failure.

The rate of replacement is expected to increase in the next RCP as the CONSAC ages and the NI meters detect increasing neutral impedance issues.

The other LV cable replacement programs include the commencement of the replacement of the early direct buried LV underground reticulation in suburbs such as Lapstone and Mt Riverview. These cables were installed with substandard construction techniques in the 1960's and are now reaching the end of their lives.

Substation civil and ancillaries

Item	Current Period (FY15 to FY19; $M)	Forecast Period (FY20 to FY24; $M)	Change ($M)
Major substation renewal works	71.0	91.0	20.0
Protection system renewal	36.9	30.4	-6.5
Ancillary systems renewal	20.0	20.0	0.0
Substation civil works renewal	34.8	29.4	-5.4
Total	**162.7**	**170.8**	**8.1**

Substation civil and ancillaries asset group shows a modest increase in proposed expenditure principally due to the $30M allowance made for future substation renewal works under program TS199. This proposed expenditure provision is based on the following:

- In the past 15 years Endeavour Energy has carried out major renewal works (including replacing whole 11kV switchboards in new control buildings and/or replacing whole switchyards with indoor busbars) at 37 zone and transmission substations. In that same period 65 zone or transmission substations passed 50 years in age giving a major project renewal rate of around 60%;

- These projects addressed the oldest and highest risk assets in the network which each had multiple confluent drivers for renewal. Going forward the substation assets are younger and generally of a higher construction standard and standard of safety than those sites were and therefore lend themselves more readily to a piecemeal like-for-like replacement strategy to extend their life and avoid wholesale replacement works; and

- 36 substations will be 50 years in age or more at the start of the forthcoming regulatory period and it is estimated, based on the current condition of the control buildings, primary switchgear and secondary switchgear and ancillary systems, as well as the location of the substation, that up to 13 may eventually require wholesale or partial replacement. Of these, a generalised estimate of 20% may require expenditure within the regulatory period. The remainder would be deferred to beyond the regulatory period.

6. AUGMENTATION CAPITAL EXPENDITURE MODELLING

6.1 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 (http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline/final-decision).

All instructions in this RIN have been read in conjunction with the AER's augex guidance document obtained from the AER's website.

6.2 In relation to information provided in Workbook 1 – Regulatory determination, regulatory template 2.4 and with respect to the AER's augex model:

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

(i) Prepared the maximum demand data (weather corrected at 50 per cent probability of exceedance) provided in the asset status tables 2.4.1 to 2.4.4, including where relevant, explanations of each of:

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

(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;

(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

(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.

In relation to 6.2(a)(i) Feeder maximum demand data was obtained from available metering and SCADA system data. There is a standard methodology employed to convert this data to 50% PoE, and this is described in the Summer Demand Forecast which is an attachment to our submission.

In relation to 6.2(a)(i)(A)-(D) see the table over and Basis of Preparation documents for tables 2.4.1 to 2.4.4

Reference Table	(A)	(B)	(C)	(D)
Table 2.4.1 (Subtransmission feeders)	Load flow models for analysis are based on 50% loads and feeder loads would thus be 50% PoE.	Measured at the relevant circuit breaker. Actual values are compared against load flow values in the TNPR process to help identify spurious results.	Based on actual. In a small number of cases in parts of the network (eg lines in the Mt Piper/Ilford Hall/Kandos area), maximum demand data on lines is not always available and data sourced from the Transmission Network Planning Review (TNPR) reports in the relevant years has been used. This data is based on load flow data and is considered to be representative of real loads.	The relationship of the values provided to raw values depend on the temperature correction applied eg for a cool summer, the raw loads will be adjusted up and for a hot summer adjusted down. The relationship between raw load and the values that reflect a 10 per cent probability of exceedance year would result in values that are generally greater than the 50% values depending on the relative temperature severity of the season.
Table 2.4.2 (Distribution feeders)	The measured maximum demand is used (after filtering of potential abnormal results) as this gives a true representation of the loads that the feeders are expected to experience in normal operating conditions.	Measured at the relevant circuit breaker. Abnormal loads are filtered by a calculation that compares observed maximums on all feeders to ensure that no "outlying" result is included in the feeder maximum loads.	Based on actual.	No temperature correction applies
Table 2.4.3 (Sub-transmission and zone substations)	Load flow models for analysis are based on 50% PoE loads.	Measured at the relevant circuit breaker(s). Substation data is generally meter quality data and is very reliable; however, readings are compared	Based on actual.	See above comment for Table 2.4.1

Reference Table	(A)	(B)	(C)	(D)
		against previous years and against SCADA data or circuit breaker summation data where there is a suspected discrepancy.		
Table 2.4.4 (Distribution substations)	The MDI reading is used directly for planning purposes. Peak loads are verified by local temperature and data monitoring before proceeding with augmentation.	Demand indicators fitted on ~80% of substations. Estimated where measurements are not available	Based on actual and estimates	No temperature correction applies

(ii) **Determined the rating data provided in the asset status 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**

(B) **the relationship of these ratings with Endeavour Energy's approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation timing, these should be defined and explained.**

Methodology for tables 2.4.1 and 2.4.4 is described in Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public.

(iii) **Determined the growth rate data provided in the asset status 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 Endeavour Energy.**

Refer to Endeavour Energy – 7.01 2018-2027 Summer Demand Forecast – August 2017 – Public.

(b) **In relation to the capex-capacity table 2.4.6, Endeavour Energy 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;**

The costs included in table 2.4.6 include all direct costs, but are exclusive of corporate overheads.

(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.**

Please refer to the Basis of Preparation (Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public) for table 2.4.6

(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.**

Please refer to the Basis of Preparation (Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public) for table 2.4.6

(c) Describe the projects and programs Endeavour Energy 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; and

(ii) the primary drivers of this capex, and whether in Endeavour Energy's view, there is any secondary relationship to maximum demand and/or utilisation of the Endeavour Energy network.

The unmodelled capex is made up of:

1. Land acquisition for future substations.

   There is a long lead time required to acquire a suitable zone substation site. Therefore land acquisition will occur in years in advance of zone substation need dates.

   Land is 53% of the unmodelled capex of the regulatory period.

2. Protection Compliance with National Electricity Rules and augmentation for HV conductors in relation to fault level constraints. This category is approximately 37% of the unmodelled capex.

   Endeavour has considered that the upgrading of HV conductors for fault level purposes be categorised as unmodelled augmentation given that it is an issue that is not directly driven by capacity needs, but rather a secondary outcome of capacity provision.

   This ensures that no damage to the line will occur as a result of the passage of fault current. There is no relationship to maximum demand.

3. LV augmentation. This is reactive to fuse blowing related customer complaints or power quality.

   Table 2.4.6 does not have a category for LV Augmentation. This category is approximately 10% of unmodelled Augex.

(d) Separately for each network segment that Endeavour Energy defined in the model segment data table 2.4.5, whether the outcome of such a project or program, whether intended or not, should be an increase in the capability of the Endeavour Energy network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level:

Endeavour has defined 37 network segment elements in table 2.4.5. These are divided into 11 segment groups, categorised as follows:

Network segment IDs	Network segment type	AER segment group
1 - 6	Lines 132kV/66kV/33kV summer or winter peaking	1
7 - 13	Transmission Substations 1, 2, 3, 4 or 8 transformers,	2

	summer or winter peaking	
14 - 19	Zone Substation 1, 2 or 3 transformers summer or winter peaking	3
20 - 21	HV Line Urban Summer or Winter	5
22 - 23	Short rural Summer or Winter	6
24 - 25	Long rural Summer or Winter	7
26 – 29	Urban Pad subs <=500kVA, >500kVA Urban Pole subs <=63kVA, <=400kVA	9
30 - 33	Short Rural Pad subs <=500kVA, >500kVA: Short Rural Pole subs <=63kVA: <=400kVA	10
34 - 37	Long Rural Pad subs <= 500kVA, >500kVA Long Rural Pole subs < =63kVA, <=400kVA	11

The full rationale behind these is contained in the Basis of Preparation (Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public) for table 2.4.5. A short version of the segment descriptions is included below.

(i) Describe the network segment, including:

(A) the boundary with other connecting network segments; and

Boundaries are as defined in the table above and as defined by network connectivity, ie subtransmission lines connect to zone substations, zones substations to HV feeders etc.

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

<u>Segment Group 1:</u> The $/MVA vary between the voltages and the ratings of the lines differ between summer and winter.

<u>Segment Group 2:</u> The capacity factor varies based on the number of transformers installed.

<u>Segment Group 3:</u> The capacity factor varies based on the number of transformers installed.

<u>Segment Groups 5, 6 and 7:</u> The $/MVA vary between summer and winter.

<u>Segment Groups 9, 10 and 11:</u> The $/MVA and capacity factor changes depending on the size of the substations.

(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;

Refer to Endeavour Energy – RIN0.05 Basis of Preparation – 30 Aril 2018 – Public for table 2.4.5.

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

Refer to Endeavour Energy – RIN0.05 Basis of Preparation – 30 Aril 2018 – Public for table 2.4.5.

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

Projects have been formulated on the forecast demand data available at the time of business case preparation. At the time of project completion forecast loads could be higher or lower than the original forecast.

(D) Endeavour Energy's views on the most appropriate probability distribution to simulate the augmentation needs of that network segment; and

There is no reason to depart from the normal distribution as proposed.

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

Parameters were compared to the thresholds for actual projects.

(iii) Regarding the augmentation unit cost and capacity factor provided, provide an explanation of each of:

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

Refer to Endeavour Energy – RIN0.05 Basis of Preparation – 30 Aril 2018 – Public for table 2.4.5.

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

Refer to Endeavour Energy – RIN0.05 Basis of Preparation – 30 Aril 2018 – Public for table 2.4.5.

(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

Segments have been chosen to avoid double counting of capacities added. Methodology of how capacity was allocated to various segments from projects is described in the Basis of Preparation (Endeavour Energy – RIN0.05 Basis of Preparation – 30 Aril 2018 – Public) for table 2.4.5. The data will be audited independently as part of the quality assurance process for the RIN tables.

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

The parameters were calculated from large samples of historical projects across different levels of the network. As such the parameters are considered reasonable estimates for each network segment. The data will be audited independently as part of the quality assurance process for the RIN tables.

(e) Explain the factors Endeavour Energy considers may result in different augmentation requirements for itself as compared to other NEM-based DNSPs. Endeavour Energy must account for the degree that different augmentation requirements are driven by differences in asset utilisation and maximum demand growth. Endeavour Energy must also explain all other factors, specific to its network, which would result in different augmentation requirements when compared to a DNSP with similar asset utilisation and maximum demand growth. The explanation must clearly indicate those factors that may impact:

(i) the maximum achievable utilisation of assets for Endeavour Energy; and

- Endeavour Energy is unique in the NEM with the amount of greenfield development proposed in its franchise area. The NSW State Government has been and continues accelerate to release large areas of rural land for urban residential and commercial development to increase the supply of housing. The State Government has been enabling large scale land release with record levels of road and transport infrastructure investment.

  Average utilization has been increasing in recent years on the existing network, although on average demand growth is expected to be lower in the existing network. Average utilisation levels of the network are unrelated to localized constraints on the urban fringe of the Endeavour network.

  Greenfield development areas will still require major network investment due to higher rates of growth creating localized constraints and geographic separation from existing network infrastructure.

- Western Sydney has a different climate to areas closer to Sydney CBD, significantly higher temperatures (order of 10degC differential) are often experienced on hot days in Western Sydney. Endeavour may have some conditions that need to be taken into account in the determination of equipment ratings. This is as a result of high levels of residential demand that has high air conditioning penetration and a resulting relatively flat load profile over an extended period. Where these load profiles exist, this has the potential to particularly affect transformer ratings (ie Segments 2 and 3) adversely.

(ii) the likely augmentation project and/or cost.

Endeavour Energy’s project costs would be similar to those in other predominately urbanised DNSPs.

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

Endeavour Energy has proposed an increase in greenfield Augex as a result of the factors described above.

7. CONNECTIONS EXPENDITURE

7.1 Provide and describe the methodology and assumptions used to prepare the forecasts of connection works including:

(a) Estimation of connection unit costs for each customer type; and

Please refer to Connections Capex section of Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public and Endeavour Energy – 10.26 Connections Capex Forecasting Model – March 2018 – Public. A lower unit rate per forecast customer is projected for total Connections Capex over the RCP as an outcome of the forecasts.

(b) Connection volumes for each customer type.

Please refer to Connections Capex section of Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public and Endeavour Energy – Connections Capex Forecasting Model – April 2018 – Public. The customer forecast by type is in the model within the "Customer Forecast" sheet.

7.2 Endeavour Energy must provide its 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;

45 years based on the economic life of the assets which are HV cables, packaged Substations and LV cables.

(b) the average consumption expected by the customer over the life of the connection; and

Based on our forecast customer number growth and forecast energy consumption growth the average annual consumption for new customers over the regulatory period is shown below:

Customer Type	Average Annual Energy Consumption (MWh)
Residential	4.04
Commercial	15.4
Industrial	776.5

(c) any other factors that influence the expected recovery of the Endeavour Energy network use of system charge to customers.

No other factors have been identified.

8. NON-NETWORK ALTERNATIVES

8.1 Identify the policies and strategies and procedures in the response to Workbook 1 – Regulatory determination, regulatory template 7.1 which relate to the selection of efficient non-network solutions.

Refer to Endeavour Energy – RIN1.03 Company Policy 9.2.8 Demand Management – August 2017 – Public and Endeavour Energy – 10.12 Demand Management & Non-Network Options Strategy – February 2018 – Public.

8.2 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.

It is part of the normal planning process to consider non-network options for all capital expenditure that complies with the National Electricity Rules (NER). Attached procedures that support this include:

- Application of the RIT-D to Network Investment Projects. Examples of our application of the RIT-D are provided in supporting attachments:
  - Endeavour Energy - 10.23 Augex Sample Business Cases FY19-24 - April 2018 – Public; and
  - Endeavour Energy - 10.24 Augex Sample Business Cases FY14-19 - April 2018 – Public;
- Endeavour Energy – 10.14 Company Policy 9.2.1 Network Planning – May 2016 – Public;
- Endeavour Energy – RIN1.26 Company Procedure GAM0113 Demand Management Program Development – April 2015 – Public); and
- Endeavour Energy – 10.12 Demand Management & Non-Network Options Strategy – February 2018 – Public.

Capital expenditure (capex) proposals are evaluated using the RIT-D process which includes the consultation process for investigating non-network options to determine the most cost effective solution. The forecast capex proposal is initially developed using the network need date and the RIT-D process determines the preferred option and the appropriate timing according to probabilistic analysis.

8.3 Identify each non-network alternative that Endeavour Energy has:

(a) commenced during the current regulatory control period; and

Endeavour Energy has not implemented any non-network options during the current regulatory period. All major projects have been driven from greenfield development converting rural areas into residential subdivisions. Endeavour Energy has implemented the following demand management trials:

2014-15	Pool pump off-peak 2 control	Cost: $197,600
2014-15	Power Factor Correction subsidies for Demand and General Supply Time of Use customers	Cost: $181,100
2015-16	DM education and recruitment Web page	Cost: $11,930
2015-16	Ripple Control interactive device	Cost: $18,700
2016-17	SolarSaver-Battery Energy Storage	Cost: $759,000
2017-18	CoolSaver using 3G DRED	Cost: $386,100

(b) **selected to commence during, or will continue into, the forthcoming regulatory control period.**

Endeavour Energy expects a non-network option will be implemented in the Penrith area and the Parklea ZS supply area during 2018-19 and 2019-20.

8.4 For each non-network alternative identified in the response to paragraph 8.3, provide a description, including cost and location.

Pool Pump Off-peak control
This trial was conducted to determine the cost effectiveness of placing pool pumps on off-peak-2 control as well as customer acceptance and the issues that exist involving chlorinators and dedicated circuits.

Power Factor Correction (PFC)
This trial was conducted to determine the cost effectiveness subsiding PFC for general supply Time of Use (ToU) customers and the required payback for demand ToU customers.

DM education and recruitment Web page
This was to produce an education and information web page and an avenue to allow customers to enrol into future demand management programs.

Ripple Control interactive device
This trial was conducted to determine the interactive features of a new Ripple Control device and to determine its ability to control a number of different appliances.

SolarSaver-Battery Energy Storage
This trial was conducted to determine the ability of batteries to provide on-call demand reduction in a cost effective manner. Also investigated was the interaction with other parties in the market and any potential conflicts with multiple parties using the batteries.

CoolSaver using 3G DRED
This trial is to be conducted to determine the ability and reliability of the 3G DRED device to control energy consumption of air conditioners during peak periods.

8.5 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 Endeavour Energy to an Embedded Generator in reflection any costs avoided by deferring augmentation of:

(a) Endeavour Energy's distribution network; or

During the current regulatory period Endeavour Energy did not make any payments to embedded generators. There may be payment in future Demand Management programs but this will not be known until a non-network option tender document is issued and response's received.

(b) the relevant transmission network.

Refer to 8.5 (a).

9. FORECAST INPUT PRICE CHANGES

9.1 Provide, in Workbook 1 – Regulatory determination, regulatory template CPI series, the CPI series and index used by Endeavour Energy in its forecast capex proposal and the forecast opex proposal.

Endeavour Energy has provided in Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public, the CPI series data and index used to derive our proposed opex and capex forecasts.

9.2 Provide, in Workbook 1 – Regulatory determination, regulatory template 2.14, the capex and opex price changes assumed by Endeavour Energy in its forecast capex proposal and the forecast opex proposal. All price changes must be expressed in percentage year on year real terms.

Endeavour Energy has provided the labour and material price changes assumed by Endeavour Energy in estimating Endeavour Energy's forecast capex and opex proposals in regulatory template 2.14. Regulatory template 2.14 is part of Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

9.3 Provide:

(a) the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;

Endeavour Energy expects non-labour price changes for the 2019-24 regulatory period to change in line with CPI. We therefore have not included the impact of forecast real materials prices changes in our capex or opex forecasts.

(b) in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and

A copy of the current Enterprise Bargaining Agreement is provided at Endeavour Energy – RIN1.04 Certified Enterprise Bargaining Agreement – May 2013 – Public.

Endeavour Energy is currently seeking to update the existing Enterprise Bargaining Agreement (EBA).

(c) documents supporting or relied upon that explain the change in the price of goods and services purchased by Endeavour Energy, including evidence that any materials price forecasting method explains the price of materials previously purchased by Endeavour Energy.

Endeavour Energy is exposed to the real changes in commodity prices through contracts that it establishes for major items of equipment such as transformers, switchgear, cables and conductor. Endeavour Energy – RIN1.24 Contract Price Adjustment Schedule – September 2011 – Confidential shows an example of a contract price variation schedule that applies to our contract for the supply of power transformers that demonstrates how commodity price changes are included in the cost of transformers.

Price changes are assessed on a regular basis by reference to relevant indices and incorporated via the formula shown in this schedule. Endeavour Energy – RIN1.23 Treasury Report – Contract Price Variations – February 2014 – Confidential provides a summary of contract price variations due to a variety of factors including commodity price changes.

9.4 Provide also an explanation of :

(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 9.3(a); and

(iv) the use of any assumptions such as lags or productivity gains;

Section 11.6 of our Regulatory Proposal provides a general overview of the forecast real price changes in the 2019-24 regulatory control period.

This information is also presented in table 2.14 and is consistent with the requirements of the Reset RIN, in particular the RIN requirements:

- labour & material price changes assumed by Endeavour energy in estimating forecast capex & opex proposals;
- consultant reports relied upon to derive price changes, copies of the EBA; and
- the price changes expressed in percentage year on year real terms.

(b) whether the same price changes have been used in developing both the forecast capex proposal and forecast opex proposal; and

The same real labour price changes have been applied to our capex and opex forecasts. The only difference is the benchmark proportion of labour the price growth forecasts have been applied to. See sections 10.3.2 and 11.6 of our Regulatory Proposal for further detail.

(c) if the response to paragraph 9.4(b) is negative, why it is appropriate for different expenditure escalators to apply.

Not applicable.

9.5 If an agreement provided in response to paragraph 9.3(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 most recent certified Enterprise Agreement for Endeavour Energy expired on the 24 December 2014. We have provided this agreement at Endeavour Energy – RIN1.04 Certified Enterprise Bargaining Agreement – May 2013 – Public.

Negotiations between the business, unions and other employee representatives on a new agreement to apply after this date commenced prior to the expiry of this agreement. This was undertaken against the backdrop of the AER's 2015-19 regulatory determination, the subsequent appeals process and the long-term lease announcement by the NSW government.

These factors and the uncertainty of their outcomes have made it difficult to reach an agreement on a new EBA.

Following the lease transaction, our new management have indicated they intend to take a renewed approach to negotiations. To facilitate this, a Bargaining Unit has been tasked with negotiating with employee representatives on reaching an agreement by early 2018.

In November 2017, the Bargaining Unit had agreed to ask the Fair Work Commission (FWC) to assist in negotiations using interest based bargaining (IBB) principles. The FWC appointed Commissioner Cribb to assist in negotiations.

Endeavour Energy has recently concluded negotiations for a replacement enterprise agreement, which has now been endorsed by employees. The Agreement is with the Fair Work Commission awaiting approval and we anticipate that this process should take a couple of months.

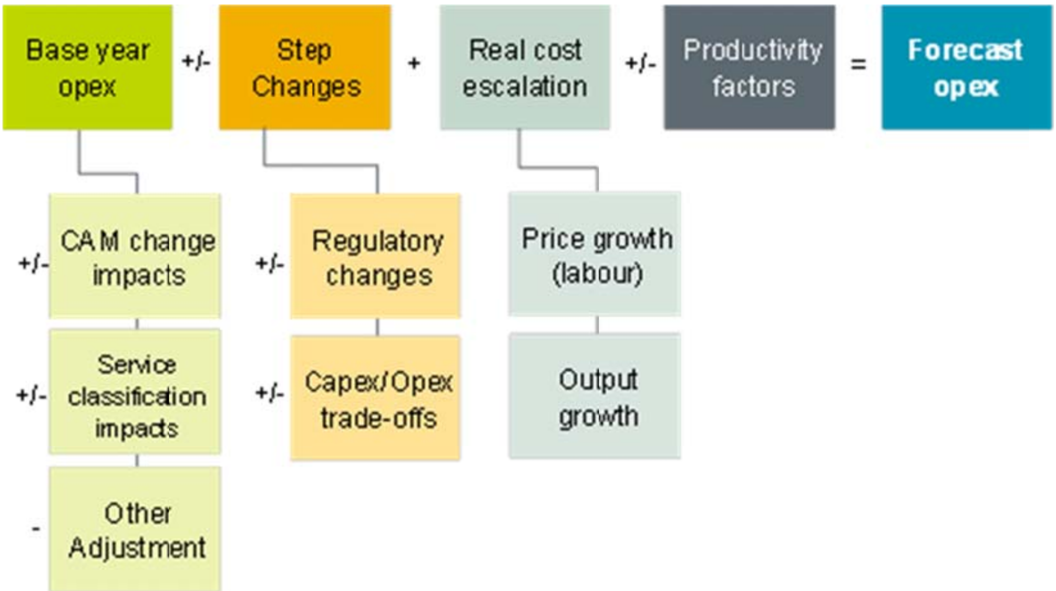
The replacement agreement, once approved by the Fair Work Commission will commence operating 7 days after it has been approved by the Fair Work Commission. The nominal expiry date of the agreement is 31 December 2020. A copy of the endorsed agreement is also attached, Endeavour Energy - RIN1.05 Proposed Enterprise Bargaining Agreement – February 2018 – Public.

10. OPERATING AND MAINTENANCE EXPENDITURE

10.1 Provide:

(a) the model(s) and the methodology Endeavour Energy used to develop total forecast opex;

Endeavour Energy has used the base-step-trend methodology for estimating our forecast opex requirements. In applying this approach we have used the AER's top-down Opex Model which can be described as follows:



To summarise, we have used 2017-18 (the fourth year of the current regulatory period) as the base year from which our 2019-24 opex forecast has been derived. We consider the opex in this year (adjusted for DMIA costs and movements in provisions) to be efficient and exclusive of non-recurring expenditure. Additionally, to provide further assurance that our base year is efficient we note it is below the opex allowance from the AER's April 2015 Determination.

Non-routine costs (i.e. debt raising costs) have been calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values.

Further information on our opex forecasts is provided in Chapter 11 of our Regulatory Proposal. The AER's Opex model which gives effect to the methodology is included at Endeavour Energy – 11.01 Opex Model – April 2018 – Public.

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

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

In order to achieve each of the operating expenditure objectives, we must have the required capabilities, personnel and systems to achieve them. For example, one of the operating expenditure objectives is to maintain the safety of the distribution system through the supply of standard control services. In undertaking this activity and in operating the necessary systems, Endeavour Energy must incur maintenance operating expenditure.

Our total forecast operating expenditure therefore comprises the costs of undertaking all the related activities and to operate the necessary systems to deliver each of the operating expenditure objectives listed in clause 6.5.6(a) of the NER. Our total forecast operating expenditure comprises two cost groups. The table below shows the operating expenditure objective/s for each cost group.

Operating expenditure cost group	Activities	Operating expenditure objectives achieved
System maintenance operating expenditure	Maintenance operating expenditure is required to undertake various activities on Endeavour Energy's electrical network. These activities, and associated cost, are critical to achieve all four operating expenditure objectives.	All operating expenditure objectives
Operation, support and other expenditure	Operation expenditure are costs incurred in undertaking the required activities to directly support the operation of Endeavour Energy's electrical network. Support expenditure is necessary for the normal operation of Endeavour Energy as a business such as management costs, financial reporting or human resources management costs. These costs would be found in any typical business. They are essential to the effective running and operation of the network and therefore required to achieve all of the operating expenditure objectives.	All operating expenditure objectives

Further description of the activities within each opex cost groups are provided below.

1. <u>System maintenance activities and costs</u>

Inspections – Routine asset inspection and condition monitoring activities include field and aerial inspection of overhead distribution assets (poles, pole top structures, conductors, substation structures, transformers, high and low voltage switchgear, and other distribution electrical equipment); powerline to ground and vegetation clearances; thermography of powerline and substation structures; and non-destructive testing of power transformers and switchgear;

Maintenance and repair – This category covers all maintenance and repair activities on network assets but excludes fault and emergency repairs and restoration of supply for planned and unplanned interruptions which are categorised as emergency response. Components include maintenance and repair of distribution powerline equipment, damaged or inoperable switchgear, distribution and zone substations, and customer service mains;

Vegetation management – This work, mainly carried out by external contractors, reduces safety hazards and interruptions to supply on our overhead electricity network. Compliance with this policy is a critical control measure associated with management of bushfire and community safety risk. Vegetation management must be done regularly to ensure a reliable and safe electricity supply. It must also be done in a way that is sensitive to environmental and community issues;

Emergency response – This covers fault and emergency repairs and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. When notified of an interruption to customer supply, Endeavour Energy promptly dispatches field employees to deal with the fault; and

Network maintenance operating cost – This cost category covers other activities that are required to support the maintenance of the network itself such as: fire mitigation (excluding vegetation management); field training; and any other cost required for the safe operation and maintenance of the distribution network.

2. <u>Operations and support activities and costs</u>

Network operations – This category of costs cover operating costs required to manage the network such as: staffing of the control centre; operational switching personnel; outage planning personnel; and provision of authorised distribution personnel. It also covers support activities directly related to the network such as: demand forecasting; procurement, logistics and stores; information technology (IT) costs directly attributable to distribution operation; and land taxes;

Information, communication and technology – costs relating to the operation and maintenance of various IT technologies and telecommunication system required for the effective operation of Endeavour Energy's infrastructure and day to day operations.

Customer service – This activity includes call centre and operational activities relating to customer interaction and reporting on issues such as: distribution faults and safety hazards; complaints about the quality and reliability of supply; queries on new connections, disconnections and reconnections; and queries on improving power factor or load factor; and

Training and development – costs relating to centralised coordination and delivery of the technical, regulatory and professional development needs for Endeavour Energy's employees and compulsory training related to network access for contractors who work on the network.

Finance costs - costs relating to:

- corporate accounting and reporting;
- budgeting, forecasting, commercial services, investment analysis and business support;
- treasury, taxation and cash management; and
- regulatory reporting and fixed asset management and reporting.

Other operations and business support costs - these relate to:

- fleet and logistics management;
- insurance;
- human resources management;
- workers compensation, occupational health, well-being and safety;
- regulation and implementation of non-network alternative programs; and
- management including the Board of Directors, Chief Executive Officer and Chief Operating Officer.

In addition to the forecast opex that Endeavour Energy proposed, the AER also allows a debt raising cost. The AER has accepted this cost as a legitimate operating expenditure that is required to meet the opex objectives.

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

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. At a high level our obligations are typically in the following areas:

- Network Management and Performance: many of our obligations directly impose requirements and standards relating to the construction, operation, repair, maintenance and safety of our network and the reliability and security of supply planning and compliance reporting. For example, our ministerially imposed licence conditions, the Electricity Supply Act 1995 (NSW) and Electricity Supply (Safety and Network Management) Regulation 2014 (NSW);

- Environment and planning: there are several requirements regarding environmental planning, assessment and consultation, handling hazardous materials, heritage considerations, land development requirements and other miscellaneous requirements;

- Safety Codes, Standards and Guidelines: There are numerous guidelines and standards that we are required to adopt (in the absence of a better alternative) under legislation such as the Work Health and Safety Act 2011 (NSW) or Electricity Supply Act 1995 (NSW). These include codes such as the National Electricity Network Safety code and various guidelines covering numerous areas of our operations including vegetation management, live line work, fire protection, working on cables, the installation of cables, application of auto-reclosers, design and maintenance of overhead distribution lines, inspection and preservation of wood poles, risk management etc;

- Employment and work, health and safety: as an employer we are subject to an array of workplace laws that relate to workplace injury, management, insurance, compensation, workplace and employment obligations, etc;

- Property: in the course of our operations we own, acquire and access a large amount of land within our network area. These activities are governed by several property laws related to Aboriginal land rights, development of land for electrical infrastructure, creation of line easements, remediation of sites, general requirements relating to construction, operation, repair, maintenance and safety, etc; and

- Other: there are several other obligations and requirements we must conform with ranging from our connection contracts to the Privacy Act 1988 (Cth) to the Competition and Consumer Act 2010 (Cth).

These obligations have a direct consequence on our policies and practices and as a result our opex requirements.

We consider that a practical demonstration that the forecast expenditure reasonably reflects each the expenditure criteria can be achieved by:

- demonstrating that the process we employed in developing our forecast expenditure is efficient and prudent. In this respect a number of the opex factors relate to the process used by Endeavour Energy; and

- using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost. In this respect, a number of the opex factors represent partial checks of the forecast.

In terms of demonstrating that our forecasting process is efficient and prudent, we have provided evidence in section 11.5 of our Regulatory Proposal and at Endeavour Energy – 0.07 Expenditure Forecasting Methodology Statement – June 2017 – Public.

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

In accordance with 6.10.1(b) and 6.11.1(b) of the NER, the AER must have regard to the operating expenditure factors as well as the information included in or accompanying Endeavour Energy's Regulatory Proposal, written submissions and any analysis undertaken by or for the AER.

We provide the tables below to demonstrate how our forecast opex satisfactorily addresses each of the factors in clause 6.5.6(e) of the NER and supports the AER's assessment.

Forecasting method related expenditure factors	Addressed
(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;	Our performance in recent years has been impacted by our *Endeavour 2020* transformation program, meeting strong growth in greenfield areas and short-term restructuring costs. In addition to ongoing issues such as the impacts of provision movements on industry performance and how the impacts of sub-transmission are addressed. Despite this, Endeavour Energy consistently ranks as an averagely efficient DNSP. We expect to achieve significant opex reductions in the 2017-18 base year that will see our MTFP and Opex MPFP scores improve. See section 3.2.2 of the Regulatory Proposal for further details. We also consider our category level performance has been improving. Also, alternate measures, specifications and analysis provides further support of our efficiency.

Forecasting method related expenditure factors	Addressed
(5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;	We have included information relating to our actual and expected performance over the 2014-19 period in section 11.4 of our proposal. We detail our efficiency programs implemented over the course of the period, the cost pressures we have managed and other key events. We forecast that we will transition to the AER's opex allowance during the 2014-19 period.
(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;	Our expenditure forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers (opex factor 5A). We engaged customers on a range of issues including reliability, price, and demand management. The findings from our customer engagement support the basis of our proposed total opex including in relation to price affordability, and maintaining current levels of safety and reliability. See section 11.2 of our Regulatory Proposal and Chapter 5.
(6) the relative prices of operating and capital inputs;	We have considered the relative prices of operating and capital inputs (opex factor 6). As noted above we have sought to assess all feasible options when addressing a need including opex and capex options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation.
(7) the substitution possibilities between operating and capital expenditure;	We have considered the substitution possibilities between operating and capital expenditure in developing our forecast opex. A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions such as maintenance, which have then been factored into our opex forecasts. The two most significant interactions between capex and opex relate to replacement capex and maintenance opex and non-network solutions. In order to maintain existing service and reliability levels we have increased our replacement capex forecast compared to recent levels (2015-16 and 2016-17) due to our ageing asset base. Our opex forecast is based on existing maintenance practices, specifically the 2017-18 base year which is reflective of an increase in replacement capex to a more sustainable long-term level. Any amendments to our replacement program are likely to have an impact on our required maintenance opex (although the relationship is difficult to quantify). In regards to non-network solutions we will incur additional opex during the period where it is efficient to do so to defer capex and in consideration of the relevant incentive schemes.

Forecasting method related expenditure factors	Addressed
(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;	Endeavour Energy was subject to the efficiency benefit sharing scheme (EBSS) for the current 2014-19 period. The EBSS provides incentives for business to pursue efficiency improvements in opex and to share efficiency gains with customers. This is demonstrated by the improvement in our opex forecast over the course of the 2014-19 period. This performance was achieved by the implementation of a number of cost saving initiatives. It has set a solid platform for Endeavour Energy in ensuring that the forecast opex for the 2019-24 is efficient. In accordance with the revealed cost, EBSS incentive framework we have forecast our opex requirements using a base-step-trend methodology.
(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;	We have considered as a partial indicator of efficiency is the extent the operating expenditure forecast is referable to arrangements with another person that do not reflect arm's length terms (opex factor 9). We confirm that our forecast opex for 2019-24 does not include any arrangement with any other person that do not reflect arm's length terms.
(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);	Endeavour Energy's forecast method considered whether any opex should be identified as contingent projects, and therefore excluded from the total forecast capex or opex for standard control services (opex factor 9). We found that no component of our opex cost categories met the criteria of a contingent projects set out in 6.6A.1 of the Rules.
(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and	Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives (opex factor 10). We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts, and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities.
(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);	Not applicable to opex.
(12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised Regulatory Proposal under clause 6.10.3, is an operating	Will only be relevant to our revised proposal, if the AER raises an additional factor in making their draft decision.

Forecasting method related expenditure factors	Addressed
expenditure factor.	

10.2 Provide:

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

Not applicable.

(b) an explanation of the driver of each non-recurrent opex;

Not applicable.

10.3 If Endeavour Energy used a revealed cost base year approach to develop its total forecast opex proposal, provide:

(a) in Microsoft Excel format, reconciliation (including all calculations and formulae) of Endeavour Energy's forecast total opex proposal to forecast standard control services opex and dual function assets opex by opex driver in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3;

Refer to Endeavour Energy – 11.01 Opex Model – April 2018 – Public.

(b) the base year Endeavour Energy used; and

2017-18 was used as the base year for Endeavour Energy's revealed cost base year approach.

Refer to Endeavour Energy – 11.01 Opex Model – April 2018 – Public.

(c) explanation and justification for why that base year represents efficient and recurrent costs;

Refer to section 11.5 of our Regulatory Proposal.

10.4 If Endeavour Energy does not use a revealed cost base year approach to develop its total forecast provide:

(a) forecast expenditure by opex category in Workbook 1 – Regulatory determination, regulatory template 2.16 for standard control services opex and dual function asset opex in tables 2.16.2 and 2.16.4;

Not applicable.

(b) in Microsoft Excel format, reconciliation (including all calculations and formulae) of Endeavour Energy's total forecast opex proposal to forecast standard control services opex and dual function assets opex by opex category in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.2 and 2.16.4;

Not applicable.

(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;

Not applicable.

(d) explanation and justification for:

(i) whether Endeavour Energy considers there is a year of historic opex that represents efficient and recurrent costs; or

(ii) why Endeavour Energy considers no year of historic opex represents efficient and recurrent costs.

Not applicable.

10.5 Provide the amount of total forecast opex attributable to output growth changes for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.

The amount of total forecast opex attributable to output growth changes for each year of the forthcoming regulatory control period has been provided in table 2.16.1. Refer to Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public

The AER have confirmed in the framework and approach for 2019-24, that distribution pricing will continue apply for all Endeavour Energy's small number of sub-transmission assets in 2019-24. This means we have no assets to report as dual function assets and therefore Table 2.16.3 of Workbook 1 is not applicable to Endeavour Energy.

10.6 Provide:

(a) the output growth drivers Endeavour Energy used to develop the amount of total forecast opex attributable to output growth changes;

Output growth relates to changes in the volume of services that we are required to provide resulting from network expansion or contraction. We expect our network will grow in the 2019-24 regulatory period (as reflected by a positive output growth value) mainly due to significant forecast increases in new connections and associated network extensions arising from planned greenfield developments.

The additional operating costs required to meet our obligations to maintain and operate a growing network is considered through our forecast output growth figures. To account for output growth the AER has developed three industry standard weighted output variables that align to economic benchmarking variables used by Economic Insights. These variables and their respective weights are as follows:

- customer numbers (67.6 per cent);
- circuit length (10.7 per cent); and
- ratcheted maximum demand (21.7 per cent).

We have adopted these variables and their weightings in calculating our output growth forecast for 2019-24. This is demonstrated in our opex model (Endeavour Energy – 11.01 Opex Model – April 2018 – Public).

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

No economies of scale factors have explicitly been applied to the growth drivers we have used. See our response to section 10.11.

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

We have adopted the methodology consistently applied by the AER in their opex decisions to account for output growth for distribution networks.

This approach was based on advice provided to the AER from Economic Insights (EI). The output factors chosen by EI (customer numbers, circuit length and ratcheted maximum demand) were based on three selection criteria, namely:

- they align with the NEL and NER objectives;
- they reflect the services provided to customers; and
- they are significant outputs which impact costs.

We consider these three drivers are the main contributors to costs related to output growth.

The weights of each are based on Economic Insights’ opex cost function analysis. We do not have any evidence that suggests additional factors or alternative weightings should apply or the current approach under (over) compensates for the impact of output growth on opex.

(d) if Endeavour Energy applied any composite multiple output growth drivers:

(i) the inputs for each composite multiple output growth driver; and

(ii) the weightings for each input;

We have not applied any output growth drivers in addition to those reported in section 10.6 (a).

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

(a) applied the output growth drivers; and

Values for each of the three factors used to determine to overall change in opex attributable to output growth were estimated in accordance to our internal forecasting processes. These estimates are based on robust and proven forecasting procedures, made by subject matter experts using the most up-to-date information and data.

Forecasting approach:

- customer numbers: Refer to Chapter 7 of our Regulatory Proposal;

- circuit Line Length: Refer to Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public, specifically information relating to tables 3.5.1.1 and 3.5.1.2; and
- ratcheted Maximum Demand: Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public, specifically information relating to table 3.4.3.

Output growth drivers were applied through the AER's Opex model (Endeavour Energy – 11.01 Opex Model – April 2018 – Public). Weights for each driver were attributed in accordance to those consistently applied by the AER and outlined in section 10.6(a) above.

(b) accounted for economies of scale.

We have not explicitly accounted for economies of scale in the output growth forecasts. Given that explicit economies of scale benefits have proven difficult to identify, assess and quantify in advance of a regulatory period, we have not adjusted our forecast output growth rate for 2019-24 for economies of scale.

As stated in Chapter 11 of our Regulatory Proposal, we undertook a significant program of cost saving initiatives during 2014-19. Benefits arising from *Endeavour 2020* during this period, including those related to economies of scale, will be reflected in our efficient revealed cost base year opex (i.e. 2017-18 opex).

The incentives offered by the EBSS in conjunction with the revealed cost base year framework ensures opportunities to benefit from economies of scale will be incentivised and incorporated in future opex forecasts. Proposing an uninformed and pre-emptive adjustment for output growth risks subduing the effectiveness of the EBSS and risks the integrity of the opex forecast.

Real price changes

10.8 Provide the amount of total forecast opex attributable to changes in the price of labour and materials for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.

The amount of total forecast opex attributable to real price growth (labour and materials) for each year of the 2019-24 regulatory period has been provided in table 2.16.1 of Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

The AER have confirmed that distribution pricing will continue apply for all Endeavour Energy's sub-transmission assets in 2019-24. This means we have no assets to report as dual function assets and therefore, table 2.16.3 Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public is not applicable.

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, Endeavour Energy applied the real price measures in Workbook 1 – Regulatory determination, regulatory template 2.14; and

Endeavour Energy engaged BIS Oxford Economics (BIS) to estimate labour price escalation values in for the 2019-24 period. It was determined that the price of labour is expected to exceed CPI forecasts and as such, we have proposed a real price of labour increase. We have not proposed a real price increase for materials.

Chapter 11 of our Regulatory Proposal details our forecast real price change. In brief, our real price estimates are based on forecast wage price index (WPI) of labour in the utilities sector (EGWWS) in NSW. Labour price forecasts were provided by BIS and their report is included as attachment Endeavour Energy – BIS – 0.10 Real Cost Escalation Forecast – September 2017 – Public. Real labour price escalators are also provided in Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public regulatory template 2.14.

To derive our overall real price change forecast, we have adopted the weightings most recently selected by the AER's benchmarking consultants Economic Insights (EI). In the report which accompanied the AER's 2017 DNSP Benchmarking Report, EI determined the labour/non-labour cost split for benchmarking opex to be 64.8% (labour) and 35.2% (non-labour).

Real price changes were applied through the AER's Opex model (Endeavour Energy – 11.01 Opex Model – April 2018 – Public).

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

As outlined in Chapter 11 of our Regulatory Proposal, real labour price changes have not been explicitly adjusted for forecast productivity changes. This is because productivity is implicitly included within the forecast WPI. This view is supported by our consultants BIS. Their report is provided as attachment Endeavour Energy – BIS – 0.10 Real Cost Escalation Forecast – September 2017 – Public.

We note previously, the AER has not used 'productivity adjusted' real wage growth information provided by Deloitte Access Economics. We support this continued approach by the AER.

Productivity change

10.10 Provide the amount of total forecast opex attributable to changes in productivity for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.

Endeavour Energy has not attributed any changes in productivity to total forecast opex. This is reflected in regulatory template 2.16 of Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

The AER have confirmed that distribution pricing will continue apply for all Endeavour Energy's sub-transmission assets in 2019-24. This means we have no assets to report as dual function assets and therefore, table 2.16.3 Endeavour Energy – RIN.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public is not applicable.

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

Productivity change can result from technical change, efficiency improvements and economies of scale and is important to consider in developing a forecast opex that is dynamically efficient. Over the 2014-19 regulatory period, productivity improvements were driven by cost savings initiatives under the *Endeavour 2020* business transformation program.

The success of these initiatives has contributed to achieving an efficient base year opex from which our forecast for 2019-24 has been built. By adopting the AER's base-step-trend method, we have locked in realised productivity improvements into forecasts of future expenditure.

We have not included a productivity adjustment factor to offset forecast output and real price growth over 2019-24. Our reasons are detailed in Chapter 11 of our Regulatory Proposal. Broadly however, we believe proposing a productivity factor risks forecasting error; is inconsistent with the NER; and undermines the effectiveness of the EBSS.

10.12 Provide an explanation of:

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

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

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

Not applicable.

11. STEP CHANGES

11.1 Provide the amount of total forecast opex attributable to opex step changes for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.

Endeavour Energy proposes not to include any step changes for standard control services opex during the 2019-24 regulatory period. As detailed in Chapter 11 of our Regulatory Proposal, we have elected to absorb all step changes as a productivity improvement.

The AER have also confirmed that distribution pricing will continue apply for all Endeavour Energy's sub-transmission assets in 2019-24. This means we have no assets to report as dual function assets and therefore, table 2.16.3 Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public is not applicable.

11.2 Provide an explanation of why Endeavour Energy considers:

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

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

(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.

Not applicable.

11.3 For all step changes in forecast expenditure provide:

(a) In Workbook 1 – Regulatory determination, regulatory template 2.17 the quantum of the step changes :

(i) forecasts for each year of the forthcoming regulatory control period; and
(ii) expected to be incurred, in the current regulatory control period;

(b) a description of the step change.

Not applicable.

11.4 For each step change listed in response to paragraph 11.3, provide an explanation of:

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

(b) what the driver of the step change is;

(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

(d) whether the step change is recurrent in nature;

Not applicable.

11.5 For each step change listed in response to paragraph 11.3, provide justification for when, and how, the step change affected, or is expected to affect:

(a) the relevant opex category;

(b) the relevant capex category;

(c) total opex; and

(d) total capex;

Not applicable.

11.6 For each step change listed in response to paragraph 11.3, provide the process undertaken by Endeavour Energy to identify and quantify the step change; provide cost benefit analysis that demonstrates Endeavour Energy proposes to address the step change in a prudent and efficient manner, including:

(a) the timing of the step change; and

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

Not applicable.

11.7 For each step change listed in response to paragraph 11.3, where the step change is due to a change in a regulatory obligation or requirement provide:

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

(b) any relevant compliance audits Endeavour Energy conducted during the previous regulatory control period or the current regulatory control period;

Not applicable.

11.8 For each step change listed in response to paragraph 11.7, provide, with reference to specific clauses of the relevant legislative instrument(s), the:

(a) previous regulatory obligation or requirement; and

(b) how the changed regulatory obligation or requirement is driving the step change.

Not applicable.

11.9 Provide the amount of total forecast opex attributable to category specific opex in Workbook 1 – Regulatory determination, regulatory template 2.17, table 2.17.5. The amount of total opex attributable to category specific opex must correspond with the category specific opex reported in Workbook 1 – Regulatory determination, regulatory template 2.16, table 2.16.1.

Endeavour Energy’s debt raising costs have been excluded from the 2017-18 base year opex and subsequently, not trended forward in line with other forms of opex. These costs are calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values.

Forecast debt raising costs have been included in table 2.17.5 Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public and correspond with the values reported in table 2.16.2.

12. ECONOMIC BENCHMARKING

12.1 Complete the Workbook 1 – Regulatory determination, regulatory templates 3.1 to 3.7 in accordance with:

(a) the 'Economic Benchmarking RIN for distribution network service providers – Instructions and Definitions' issued to Endeavour Energy on 28 November 2013, chapters 2 to 9;

(b) paragraphs 12.2 to 12.10.

Regulatory templates 3.1 to 3.7 in have been completed in accordance with the Economic Benchmarking RIN for distribution network service providers - Instructions and Definitions (November 2013) and the instructions in paragraphs 12.2 to 12.10.

These regulatory templates are included within Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

12.2 The forecast revenue groupings in Workbook 1 – Regulatory determination, regulatory templates 3.1, tables 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous regulatory years. However:

(a) Total revenues must equal the total forecast revenues proposed by Endeavour Energy in its Regulatory Proposal, and

(b) Revenue groupings must reflect Endeavour Energy's forecast demand for its services in the forthcoming regulatory control period in its Regulatory Proposal.

The forecast revenue groupings in tables 3.1.1 and 3.1.2 within Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public equal the total forecast revenues as proposed by Endeavour Energy in the Regulatory Proposal and the revenue groupings reflect Endeavour Energy's forecast demand for services in the forthcoming regulatory control period.

12.3 Information provided in Workbook 1 – Regulatory determination, regulatory templates 3.2, tables 3.2.1 and 3.2.2 must reflect Endeavour Energy's cost allocation method.

The opex amounts reported in regulatory template 3.2 have been prepared in accordance with the approved CAM (Endeavour Energy – 0.06 Cost Allocation Method – February 2018 – Public) for Endeavour Energy.

12.4 RAB asset financial data in the Workbook 1 – Regulatory determination, regulatory template 3.3 must reconcile to that in Endeavour Energy's Regulatory Proposal PTRM and RFM.

RAB asset financial data in the Assets (RAB) regulatory template (specifically values in table 3.3.1) reconcile to those in Endeavour Energy's PTRM and RFM. Refer to Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

12.5 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)

The definition of a tree has been 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).

12.6 In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Endeavour Energy is not responsible for the vegetation management associated with the span are not to be counted.

In calculating response to the variables DOEF0202 to DOEF0205, spans where Endeavour Energy is not responsible for the vegetation management associated with the span have not been counted.

12.7 “Total number of spans” (DOEF0205) does not include service line spans.

It is confirmed that “Total number of spans” (DOEF0205) does not include service line spans.

12.8 Endeavour Energy 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).

It is confirmed that Endeavour Energy has reported the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length against “Rural proportion” (DOEF0201).

12.9 For the purposes of calculating the “Route line length” variable (DOEF0301) or other variables measured in terms of route line length:

(a) the length of service lines are not to be counted

(b) the length of a span that shares multiple voltage levels is only to be counted once

(c) the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately

For the purposes of calculating the “Route line length” variable (DOEF0301) or other variables measured in terms of route line length:

- The length of service lines are not counted;
- The length of a span that shares multiple voltage levels is only counted once; and
- The lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

In relation to Item (iii) geospatial buffers of 0.1metre, 0.5metres and 10% were used in gathering the spatial data, which meant a minor possibility of two sets of lines in the same easement being captured once (rather than separately). However, spot checks of results indicated this was not an issue, and generally ORB spatial capture standards for offsets, indicate this should not be an issue.

12.10 All forecast variables in the Workbook 1 – Regulatory determination, regulatory templates 3.1 to 3.7 must align with those in Endeavour Energy's Regulatory Proposal. For the avoidance of doubt this includes forecast:

(a) opex and capex;
(b) maximum demand, customer numbers, energy delivery;
(c) revenues;
(d) quality of services variables including SAIDI and SAIFI; and
(e) quantities of physical assets

Each of the forecast variables in regulatory templates 3.1 to 3.7 align with those stated within our Regulatory Proposal. Refer to Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

13. ALTERNATIVE CONTROL SERVICES

13.1 The overheads relating to each alternative control service listed in paragraph 13.2 must be disclosed.

Refer to regulatory templates 2.10 and the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Confidential) Pricing Models.

13.2 Provide a list of all of the alternative control services that Endeavour Energy intends to provide to customers and levy charges for in the forthcoming regulatory control period.

Refer to the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Confidential) Pricing Models.

13.3 Provide a definition of each alternative control service listed in paragraphs 14, 15 and 16.

Refer to the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Public) Pricing Models.

Our service definitions are as per the AER's Final F&A paper for the 2019-24 period.

13.4 For each alternative control service listed in paragraphs 14, 15 and 16, 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.

Refer to the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Confidential) Pricing Models.

13.5 For each alternative control service listed in paragraphs 14, 15 and 16, specify the total revenue earned by Endeavour Energy in each year of the current regulatory control period and forecast to be earned in the forthcoming regulatory control period.

Refer to regulatory template 3.1 and the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Confidential) Pricing Models.

13.6 For each alternative control service listed in paragraphs 14, 15 and 16, 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).**

Refer to the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Public), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Public) Pricing Models.

13.7 List each material category (e.g. meters, poles, brackets) required for the provision of each alternative control service listed in the response to paragraphs 14, 15 and 16.

(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.**

Refer to the ANS (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Public), Metering (Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public) and Public Lighting (Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Confidential) Pricing Models.

14. FEE BASED AND QUOTED ALTERNATIVE CONTROL SERVICES

14.1 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 Endeavour Energy's annual pricing proposals.

(a) specify if the charges are for fee based and/or quoted alternative control services;

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential).

(b) explain the reasons for the different charge with reference to the costs incurred;

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential).

(c) explain the method used to set the different charge; and

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential).

(d) provide the calculations underpinning the different charge.

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential).

14.2 Identify the tasks involved in providing the service in Workbook 1 – Regulatory determination, 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.

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential).

14.3 If materials are required to provide the service, specify each material category.

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Confidential).

14.4 Provide all current and proposed charges for each fee based and quoted alternative control service in the current and forthcoming regulatory control periods.

Refer to the ANS Pricing Model (Endeavour Energy – 14.10 ANS Pricing Models – April 2018 – Public).

15. METERING ALTERNATIVE CONTROL SERVICES

15.1 For metering alternative control services for the current regulatory control period and the forthcoming regulatory control period, provide details of the:

(a) direct materials and direct labour costs;
(b) installation costs;
(c) meter purchase costs;
(d) volumes of work;
(e) other costs associated with providing metering services;
(f) type of meters installed and forecast to be installed, separately for new meters and for replacement meters;
(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
(h) the total operating and maintenance costs incurred, and forecast to be incurred, for metering services.

Refer to supporting attachments:

- Regulatory template 4.2 in attachment Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public;
- Endeavour Energy – Energeia – 14.02 Metering – Cost of Service Model – November 2017 – Confidential; and

15.2 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;

Refer to supporting attachments:

- Endeavour Energy – Energeia – 14.02 Metering – Cost of Service Model – November 2017 – Confidential;
- Endeavour Energy – Energeia – 14.04 Metering – Volumes Model – November 2017 – Confidential; and
- Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public.

(b) the labour costs involved in providing the service, including any overheads;

Refer to supporting attachments:

- Endeavour Energy – Energeia – 14.02 Metering – Cost of Service Model – November 2017 – Confidential;
- Endeavour Energy – Energeia – 14.04 Metering – Volumes Model – November 2017 – Confidential; and
- Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public.

(c) any materials costs involved in providing the service;

Refer to supporting attachments:

- Endeavour Energy – Energeia – 14.02 Metering – Cost of Service Model – November 2017 – Confidential;
- Endeavour Energy – Energeia – 14.04 Metering – Volumes Model – November 2017 – Confidential; and
- Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public.

(d) the number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;

Refer to regulatory template 4.2 of attachment Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 3 0 April 2018 – Public for volumes of Metering Alternative Control Service work related to individual metering service activities. These volumes were estimated based on expert advice provided by Energeia. Refer to Endeavour Energy – Energeia – 14.04 Metering – Volumes Model – November 2017 – Public.

(e) the charge per service; and

Refer to supporting attachments:

- Endeavour Energy – Energeia – 14.02 Metering – Cost of Service Model – November 2017 – Confidential;
- Endeavour Energy – Energeia – 14.04 Metering – Volumes Model – November 2017 – Confidential; and
- Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public.

(f) the revenue earned by each service.

Refer to supporting attachments:

- Endeavour Energy – Energeia – 14.02 Metering – Cost of Service Model – November 2017 – Confidential;
- Endeavour Energy – Energeia – 14.04 Metering – Volumes Model – November 2017 – Confidential; and
- Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public.

15.3 For metering 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.

Refer to attachment Endeavour Energy – 14.06 Metering Pricing Model – November 2017 – Public.

16. PUBLIC LIGHTING ALTERNATIVE CONTROL SERVICES

16.1 Specify which items are capex and operational expenditure for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period.

CAPEX

1. All expense under Non-Contestable Street Lighting projects;
2. Gift tax paid on Contestable Street Lighting Projects;
3. Replacement of condemned column/bracket;
4. Replacement of a column during an impact; and
5. Replacement of a luminaire as an improvement to the old luminaire e.g. 80W to StreetLED 17W.

OPEX

1. Condition based maintenance.
2. Fault and emergency. Outage Management System calls.
3. Routine column inspection / patrol.
4. Bulk lamp replacement.
5. Replacement of a like for like luminaire.

16.2 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.

For unit costs of the current regulatory period and forecast for items 16.2 (a), (b), (C), (d), (e) and (g) refer to Endeavour Energy – RIN1.18 Item Usage & Forecast with Price – July 2017 – Public.

For labour rates 16.2 (f) refer to Endeavour Energy – RIN1.19 Labour rates – July 2016 – Confidential.

For street lighting the Elevated Work Platform (EWP) lease rate is $80,286 / year per EWP. The forecast for forthcoming regulatory period is expected to be at the CPI increase level. This is considered at 2.5% each year.

Pro rata Traffic Management for July 2017– June 2018 is $103,140. (July 2017 to October 2017 Actual Traffic Management = $34,380). Forecast for future years is expected to increase at the CPI 2.5% (anticipated) and asset increase of 1.9%. That is for July 2018 to June 2019 is expected to be $103,140 X 1.025 X 1.019 = $107,727.

16.3 Provide the depreciation period in years for each type of luminaire.

20 years for all types except LED luminaires where it is 12 years.

16.4 Provide the bulk change cycle in years for lamps and photoelectric cells.

Lamps: 3 years for all lamps except High Pressure Sodium lamps where it is 4 years.
Photo cell: No bulk change plan is in place.

16.5 Provide details of the average replacement age of each type of luminaire.

Though the average replacement age is not available, it is assumed to be 20 years for all luminaires except for LED luminaires where it is expected to be 12 years.

16.6 Provide the number of luminaires, by type.

Refer to Endeavour Energy – RIN1.20 Public Lighting Luminaires by type – July 2017 – Public.

16.7 Provide the number of luminaires, poles and brackets replaced per year, for the current and forthcoming regulatory control periods.

For indicative usage of each street light asset refer to Endeavour Energy – RIN1.18 Item Usage & Forecast with Price – July 2017 – Public. This includes both, the new installations and replacements as a consequence of a maintenance event. Streetlight Assets increase at an annual rate of 1.9% per annum (Public Lighting Luminaires in 2006 = 166,479; Public Lighting Luminaires in 2017=204,650 showing an average growth of 1.9% per year). This is based on the past eleven year data. Future projections are anticipated at 1.9% growth each year.

16.8 Provide details, including assumptions used, for any other costs that are incurred for the provision of public lighting services.

Other direct or indirect costs which are incurred at regular interval are listed below:

1. Traffic management during installation/repair;

2. Various reports prepared for councils (5 types), two council meetings each year, regular feedback to councils on lighting issues. (Total 900 engineer hours per year).; and

3. Field surveys and audits. 300 man hours per year.

16.9 Provide models and/or modelling that underpins proposed charges for the forthcoming regulatory control period and the reasons for the assumptions behind those forecasts.

Refer to Endeavour Energy – 14.09 Public Lighting Pricing Model – March 2018 – Confidential.

16.10 For 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.

There are currently 34 public lighting accounts that are billed each month during the current regulatory control period. It is expected to remain same for the forthcoming regulatory control period.

17. DEMAND AND CONNECTIONS FORECASTS

17.1 Provide and describe the methodology used to prepare the following forecasts for the forthcoming regulatory control period:

(a) maximum demand; and

Weather correction is applied to the peak demands at substations where there is a strong relationship between demand and temperature. Summer demands at zone substations in the Blue Mountains and demands of all high voltage customers are not subject to any weather normalisation.

A weather normalisation method based on a simulation approach has been developed and adopted. This is used to normalise peak demands for the Endeavour Energy network area. Two reference weather stations are employed for temperature correction of the maximum demand (TCMD) for summer. One weather station at Nowra is used for the South Coast area which covers the Dapto BSP Region and the other weather station at Richmond is used for the remaining Endeavour Energy areas. The temperature correction method is basically divided into the following steps:

- to develop/update a regression model for estimating the relationship of demand, weather and periodic patterns (calendar effects) of demand; and
- to simulate the demand using multi-years of historical weather data to produce 10% and 50% normalised demand.

For summer, the regression model used the most recent six years of daily maximum demand and temperature to determine the relationship between demand, weather and periodic patterns of demand. Various input parameters were employed for the model. Day of the week variables accounted for the difference between daily peak by day of the week and workday/non-workday. A set of holiday variables were included to describe the load reductions associated with holidays.

Separate variables were used for the following days: New Year's Day, Australia Day, and Christmas. In addition, a school holiday variable was introduced to capture the reduced loads (increased loads in some south coast zone substations) occurring during the school holiday period in December and January. Monthly and bimonthly variables captured some of the seasonal demand variations. Year variables described the changes in base load level for each year. Previous hot day effect variables were included to explain the impacts of the successive hot days on daily peak demand.

From the regression model, daily demands were estimated using 24 years of daily weather data available at the reference weather stations. Annual seasonal maximum demands were derived from the calculated daily demands. The 10% and 50% demand values were computed from the distribution of annual seasonal maximum demands to give the 10% and 50% PoE TCMD values. The TCMD values for the latest year are the starting points of the peak demand forecasts.

Peak demand forecast considers the growth from the existing customers as well as the new customer connections. The forecasting process can be divided into two major steps. The first step is to estimate the organic growth at the zone substation which specifies the internal growth from its existing customers likely to be experienced over the forecast period. The organic growth (both positive and negative) for each zone substations was taken from the results of the NIEIR report[3] prepared for Endeavour Energy on post model adjustments for peak demand forecasts. The reports estimated the demand impacts from different state and national energy policies and programs, such as Minimum Energy Performance Standards (MEPS), NSW Energy Savings Scheme (ESS), change of building codes and NSW Solar Bonus Scheme (SBS) as well as the emerging solar battery storage and electric vehicles. This growth at the zone substation was used to establish the base level of the 10-year forecast. Due to these schemes the resultant growth in established areas is negative.

The second part of the forecast process involves incorporating the planner's inputs to the base level forecast. The inputs include new developments planned to occur (lot releases), new load increases expected from customer applications (spot loads) and also information regarding the transfer of load from one zone or subtransmission substation to another (load transfers). The final forecast at a zone substation is derived from the base level forecast after adjustment for planned load transfers, spot loads, land releases and re-development within the zone substation load catchment area.

The final forecasts for all zone substations were presented to the Network Planners for review and confirmation of the expected demand growth. The Network Planners' local knowledge is vital in determining load transfer, embedded generation, proposed spot-loads and predicted lot release information. This feedback also provides an audit trail for quality purposes. The forecast at transmission substations and bulk supply points is based on the rolled up zone substation forecast and calculated using the corresponding historical diversity factors.

The following Branch Procedure and Branch Workplace Instruction have been provided:

- Endeavour Energy – RIN1.06 Branch Procedure NFB0010 Network Demand Forecasting – February 2016 – Public; and
- Endeavour Energy – RIN1.07 Branch Workplace Procedure WFB0001 Network Demand Forecasting – April 2016 – Public.

(b) number of new connections.

Endeavour Energy considers the number of new connections to be the increase in customer numbers in each year.

Endeavour Energy's customer number forecasts are produced using the following methodology and assumptions:

- Short-term Domestic customer numbers for the months remaining in the current financial year (FY18) and next financial year (FY19) are forecast using historical trends. Long-term forecasts for FY20 to FY24 are produced using a projection of household number growth for the Endeavour Energy network area. Household growth rate projections are sourced from a third-party macroeconomic forecaster, the National Institute of Economic and Industry Research (NIEIR; September 2017);

- Short-term Commercial and Industrial customer numbers take account of recent monthly movements. Long-term forecasts increase in line with the forecast GSP

[3] NIEIR(2013): Post-modelling adjustments of forecasts to 2024-25 for Endeavour Energy. National Institute of Economic and Industry Research

growth rate as sourced from NIEIR (September 2017). The exception to this is large, site-specific industrial customers and non-metered commercial customers, which are assumed to remain broadly unchanged. The NIEIR report is provided as Endeavour Energy – NIEIR – 7.03 Economic Scenarios for the Endeavour Region 2017-2029 – September 2017 – Public.

17.2 Provide:

(a) the model(s) Endeavour Energy used to forecast new connections and maximum demand;

The following new connections models are attached to this RIN:

- Endeavour Energy – RIN1.21 Long-Term Customer Numbers – December 2017 – Confidential;
- Endeavour Energy – RIN1.22 Short-Term Customer Numbers – December 2017 – Confidential; and

Endeavour Energy does not have a specific model for developing maximum demand forecasts. A methodology has been developed and the details of this are summarised in section 17.1 (a) and Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public.

(b) where Endeavour Energy's approach to weather correction has changed, provide historically consistent weather corrected maximum demand data, as per the format in Workbook 1 – Regulatory determination, regulatory templates 3.4 and 5.4 using Endeavour Energy's current approach. If any of this data is unavailable, explain why;

The weather correction methodology was changed to a simulation based approach in FY16. The method takes six years of historical data in the regression model for weather correction. The weather normalised peak demands had been recalculated for FY10 to FY15. However, those prior to this period were not recalculated as they were not used to produce future peak demand forecasts under the current method. Regulatory template 5.4 complies as only two year of historical data is provided. Regulatory template 3.4 which contains the aggregate data back to 2005-06 does not fully comply with this request. Corrected data back to 2009-10 covers the two previous regulatory periods plus the current period. Endeavour believes that this information should be adequate however, if the AER requires the corrected data back to 2005-06 please let us know and we will perform this work.

(c) for new connections, volume expenditure data requested in Workbook 1 – Regulatory determination, regulatory template 2.5; and

The volume data for the number of new connections is provided in regulatory template 2.5 of Endeavour Energy – RIN0.01 Final RIN Workbook Reset – 30 April 2018 – Public.

(d) any supporting information or calculations that illustrate how information extracted from Endeavour Energy's forecasting model(s) reconciles to, and explains any differences from, information provided in Workbook 1 – Regulatory determination, regulatory templates 2.5, 3.4 and 5.4.

Endeavour Energy does not use customer connection numbers as an input to the demand forecasting methodology. The demand forecasting methodology output is used to populate tables 3.4 and 5.4, therefore, there is no need to reconcile as it is the same data.

For future land release areas, planners use maximum lot release statistics to determine ultimate demand for the release area. The diversified demand is included into the forecast of the zone substation using an S-curve growth rate pattern over a specific period of time. This data is different to customer connection numbers and the forecast of new connections. Please refer to the Basis of Preparation for the respective tables.

17.3 For each of the methodologies provided and described in response to paragraph 17.1, and, where relevant, data requested under paragraphs 17.2(b) and 17.2(c), explain or provide (as appropriate):

(a) the models used;

A weather normalisation model is used to adjust the maximum demand to the reference weather conditions. A Post Model Adjustment model is used to account for future reduction and increases in demand resulting from government policies and technology. The forecast demand for lot releases is estimated by an S-curve method. Future spot loads are diversified and added to the forecast. Planned load transfers are also included in the forecast for each zone substation. For further information please refer to the Descriptions of Peak Demand Forecast Method in the Basis of Preparation.

For customer number forecast, refer to see section 17.2 (a) above.

(b) a global[4] (top-down) and spatial[5] (bottom-up) demand forecast;

Endeavour Energy uses a bottom up approach for peak demand forecast. For further information please refer to the Descriptions of Peak Demand Forecast Method in the Basis of Preparation.

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

In summer, historical temperatures at Nowra are used for temperature correction of the maximum demand of the zone substation and subtransmission substations in the South Coast. Historical temperatures at Richmond are used for temperature correction of the maximum demand of the zone substation and subtransmission substations in the remaining Endeavour Energy areas. In winter, historical temperatures at Richmond are used for temperature correction of the maximum demand within the whole Endeavour Energy region.

The new developments planned to occur (lot releases) and new load increases expected from customer applications (spot loads) used in the forecast model are

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4 A global level forecast is the demand forecast that applies to the network service provider's entire network.

5 A spatial forecast applies to elements of the network. For transmission network service providers (TNSPs), spatial forecasts could be at the level of connection points with distribution network service providers (DNSPs) and major customers. For DNSPs, spatial forecasts could be at the level of connection point, zone substations and/or HV feeders.

revised according to the latest economic growth and the change of customer demand. The total estimated solar generation over the forecast period is based on the current trend of number of PV installations and is adjusted to the forecasts at the network level. This is included as part of the overall post model adjustments which also include Energy Savings Certificates, MEPS, and EV's. For further information please refer to the Descriptions of Peak Demand Forecast Method in Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public.

Inputs and assumptions used in the customer number models are contained in the following documents received from a third-party macroeconomic forecaster, the National Institute of Economic and Industry Research (NIEIR) and is attached as Endeavour Energy – NIEIR – 7.03 Economic Scenarios for Endeavour Energy – September 2017 – Public.

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

A weather normalisation method based on a simulation approach has been developed and adopted. This is used to normalise peak demands for the Endeavour Energy network area. Two reference weather stations are employed for temperature correction of the maximum demand (TCMD) for summer. One weather station at Nowra is used for the South Coast area which covers the Dapto BSP Region and the other weather station at Richmond is used for the remaining Endeavour Energy areas. The temperature correction method is basically divided into the following steps:

- To develop/update a regression model for estimating the relationship of demand, weather and periodic patterns (calendar effects) of demand; and
- To simulate the demand using multi-years of historical weather data to produce 10% and 50% normalised demand.

For summer, the regression model used the most recent six years of daily maximum demand and temperature to determine the relationship between demand, weather and periodic patterns of demand. Various input parameters were employed for the model. Day of the week variables accounted for the difference between daily peak by day of the week and workday/non-workday. A set of holiday variables were included to describe the load reductions associated with holidays.

Separate variables were used for the following days: New Year's Day, Australia Day, and Christmas. In addition, a school holiday variable was introduced to capture the reduced loads (increased loads in some south coast zone substations) occurring during the school holiday period in December and January. Monthly and bimonthly variables captured some of the seasonal demand variations. Year variables described the changes in base load level for each year. Previous hot day effect variables were included to explain the impacts of the successive hot days on daily peak demand.

From the regression model, daily demands were estimated using 24 years of daily weather data available at the reference weather stations. Annual seasonal maximum demands were derived from the calculated daily demands. The 10% and 50% demand values were computed from the distribution of annual seasonal maximum demands to give the 10% and 50% PoE TCMD values. The TCMD values for the latest year are the starting points of the peak demand forecasts.

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

The planner's inputs in the forecasting methodology include new developments planned to occur (lot releases), new load increases expected from customer applications (spot loads) and also information regarding the future transfer of load from one zone substation to another (load transfers). The forecast demand for lot releases is further estimated by an S-curve method. The spot loads are diversified prior to inclusion in the forecast. These forecast demands from block loads are added to the base level forecast described in 8.1(a). The final forecast at a zone substation is derived from the base level forecast after adjustment for planned load transfers, spot loads, land releases and re-development in the zone substation area). For further information please refer to the Descriptions of Peak Demand Forecast Method in Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public.

(f) each appliance model[6] used, where used, or assumptions relating to average customer energy usage (by customer type);

For the demand forecast, Endeavour Energy do not use appliance energy consumption or customer type energy usage assumptions or models.

(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 same forecasting methodology is used for each zone substation. Forecasts at transmission substations and bulk supply points are calculated by the corresponding historical diversity factors. A comparison is made between the previous forecast and actual data for the network to monitor the forecast performance. The post model adjustments will be updated with a new report. For further information please refer to the Descriptions of Peak Demand Forecast Method in Endeavour Energy – RIN0.05 Basis of Preparation – 30 April 2018 – Public.
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(h) how the resulting forecast data is consistent across forecasts provided for each network element identified in Workbook 1 – Regulatory determination, regulatory template 5.4 and system wide forecasts;

The forecast for zone substations, subtransmission substations and the network level provided in regulatory template 3.4 and 5.4 follow the methodology described in 17.1(a) and 17.3(d) above.

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

(i) capex forecasts; and

The demand forecasts are compared with existing capacities for zone and transmission substations to identify constraints. In greenfield development areas

6 A NSP may incorporate an appliance model in its demand forecasting method to account for the effects of the uptake of appliances (such as air-conditioners) on maximum demand.

it is relevant to compare the demand forecast to existing 11kV feeder capacity as there may be significant costs and physical limitations with developing feeders from the closest existing substation. The majority of Endeavour Energy's growth related capex forecast is in greenfield areas.

The capital expenditure program is developed by identifying when the existing capacity of an area is exceeded and identification of the preferred option to supply additional capacity.

For our existing subtransmission network, the 10 year demand forecasts are used in the annual Transmission Network Planning Review (TNPR) (Endeavour Energy – 10.11 Transmission Network Planning Review 2017-2026 – October 2017 – Public). These forecasts are used as the basis of load flow analysis to determine if there is capacity or voltage constraints on the subtransmission network including lines and substations. The TNPR (Endeavour Energy – 10.11 Transmission Network Planning Review – October 2017 – Confidential) includes the forecast year of constraint based on the load flow analysis and provides a trigger for further investigation to verify the constraints including ratings verification and load transfer capability. If the constraint is verified, a likely solution is put forward in capital expenditure forecasts over a 10 year period in the Strategic Asset Management Plan (SAMP) (Endeavour Energy – 10.03 Capex Proposal (SAMP) – March 2018 – Public).

Refer to section 10.5 of our Regulatory Proposal. Customer number forecasts are used to support our proposed connection capex amounts.

(ii) operating and maintenance expenditure forecasts.

Operating and maintenance forecast is carried out based on asset growth rates. Asset growth is a result of new customer connections and the organic growth of the network. Currently asset growth rate rates are calculated based on known major projects such as TS & ZS and historical data.

Refer to section 11.6.2 of our Regulatory Proposal. Customer number forecasts are an output growth measure input to the AER's opex model.

(j) whether Endeavour Energy used the forecasting model(s) it used in the joint planning process for the purposes of its Regulatory Proposal;

The demand forecasts are formally provided to TransGrid each year to facilitate joint planning processes. Proposed future projects that affect both Endeavour and TransGrid are considered in joint planning meetings.

(k) whether Endeavour Energy's forecasts both coincident and non-coincident maximum demand at the feeder, connection point, sub-transmission 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);

Endeavour Energy forecasts non-coincident maximum demand at the zone substation for the 10% PoE and 50% PoE levels. Peak demand forecasts at transmission substations, bulk supply points and Endeavour Energy system level are calculated by the corresponding historical diversity factors and are also non-coincident. Endeavour Energy does not produce any coincident maximum demand forecast.

Sanity checks are made for the reasonableness of the forecast but there is no reconciliation of peak demand forecast at Endeavour Energy system level by an independent econometric model.

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

Endeavour Energy records historic maximum demand in MW and MVA for most of the subtransmission substations and zone substations. Where data is missing the MVA values are estimated from the assumed power factors.

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

Endeavour Energy uses 50% probability of exceedance values for network planning but produces both 10% and 50% probability of exceedance peak demand forecast.

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

The annual Transmission Network Planning Review (Endeavour Energy – 10.11 Transmission Network Planning Review 2017-2026 – October 2017 – Public) to our Regulatory Proposal) includes contingency analysis for N-1 scenarios. Endeavour Energy applies the 50% POE forecast demands in the contingency analysis carried out. For further details refer to the response to paragraph 5.2(c) under the sub-heading 'major projects program'.

(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;

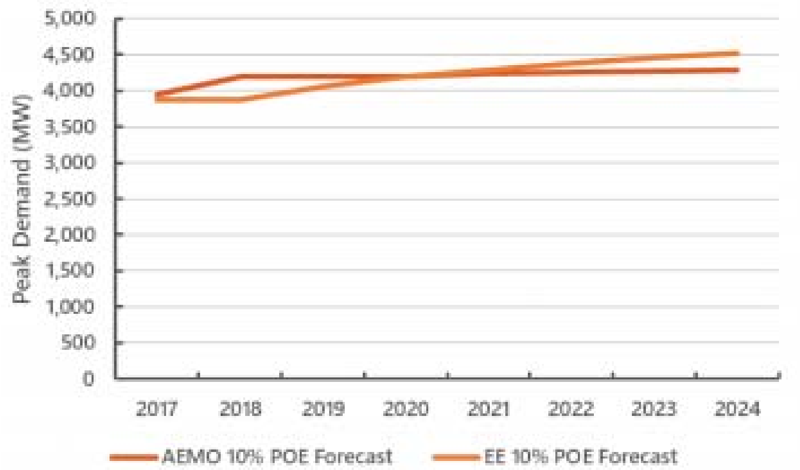
The annual Transmission Network Planning Review (Endeavour Energy – 10.11 Transmission Network Planning Review 2017-2026 – October 2017 – Public) includes load flow analysis showing load in each network element in both normal and contingency scenario. As such if load is being shared unevenly due to a mismatch of impedance, the TNPR takes this into account. Operationally these risks can be managed by split bus configurations or changeover schemes. Although the TNPR identifies locations with constraints under single contingency in a deterministic manner, the case for augmentation is based on probabilistic planning methodology taking into account expected unserved energy at the location. Demand Management agreements are put in place with customers where prudent to defer capital expenditure. This results in a reduction of load at risk on days with high load (for example a hot day event).

(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 Endeavour Energy's network;

Endeavour Energy connection point demand forecasts are greater than AEMO's. AEMO forecasts 8% increase between 2017 and 2024 while Endeavour forecasts a 17% increase as shown below. The different starting points are understood to be due to differences in mapping of load to connection points and different temperature correction methodologies, such that a direct one to one comparison is not appropriate.

Another major difference is AEMO's approach to new industrial spot loads. AEMO uses a threshold of 5% of the connection point maximum demand before applying a spot load. This varies from relatively small spot load, for example at Ilford (where 5% is equivalent to approximately 0.2MW) to very large at the Western Sydney BSP (where 5% is equivalent to approximately 170MW). Endeavour includes these spot loads as they are very material to the load on a distribution network, particularly for releaser areas where the existing network is mainly rural in construction.

The reasons for the differences are both methodological and due to the difference in assumptions and input. Although significant, the differences in the forecast are not relevant to capex. This is because the differences are mostly associated with existing demand in established areas, whereas capex is being driven by new connection.



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

Ratings for zone substations are sub-transmission lines are determined in according with our Asset Ratings Policy (refer to Endeavour Energy – RIN1.27 Company Policy 9.2.10 Network Asset Ratings – March 2018 – Public). Cyclic ratings for zone substation transformers are determined when required, however consideration needs to be given to other limiting factors such as the transformer cables, circuit breakers, CTs and busbars. For subtransmission lines, a cyclic ratings calculation is performed for underground cables. For overhead lines emergency ratings are used in contingency scenarios where available, this is dictated by the ability to maintain a safe ground clearance.

(r) where Endeavour Energy 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;

A forecast of overloaded feeders has been developed to provide a proposed expenditure for the 2019-24 regulatory period. Known major load transfers between zone substations are documented in Endeavour Energy – 7.01 2018-2027 Summer Demand Forecast – August 2017 – Public. Our approach to overloaded 11kV feeders is to be reactive, no investigations are carried out until actual demand exceeds design capacity threshold. There for individual 11kV feeder loading issues load transfers are not planned beyond 12 months.

Refer to the Endeavour Energy – 10.05 Distribution Works Program – April 2018 – Public.

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

Zone Substation load growth rates were calculated using the demand forecast for each zone substation. These growth rates were applied to distribution feeders. Any feeder load that exceeded 240 Amps within the regulatory period due to the load growth rates were highlighted as potential overloaded feeders. Endeavour Energy takes a risk basked approach as explained in the Distribution Works Program (Endeavour Energy – 10.05 Distribution Works Program – April 2018 – Public) to minimise Augex required where only a small subset of overloaded feeders require investment in any year.

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

Future load transfers and block loads were considered by individual planners on a case by case basis. The planners also verified each potential overloaded feeder considering impacts of committed augmentation projects.

Refer to the Distribution Works Program (Endeavour Energy – 10.05 Distribution Works Program – April 2018 – Public).

Typically, most areas with a large number of spot loads are new subdivisions will have the 11kV network augmented via connection works instigated by developments and associated connection headworks funded by Endeavour Energy, which is separate to Augex funding.

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

Embedded generation that was activated during a peak event period is added back to the peak demand of the zone substation. Embedded generation that is normally on as a result of customer activity and is not accounted for in the zone substation demand is separately subtracted from the substation that is affected.

Where Endeavour Energy engages an embedded generator for peak demand reduction no Demand-Related Capex projects will proceed until the network peak demand increases to a point where network capacity is insufficient to safely and reliably supply the demand. Therefore, the assumptions on the impact of the demand levels are:

- embedded generation performance where no specific performance agreements exist (eg solar PV) is incorporated in the load history and will continue unchanged into the future;

- the engaged embedded generator will be available for demand reduction on request;

- the agreed timing and quantity of demand reduction will be provided on request; and

- No diversity is to be allocated to the demand reduction level.

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

Future committed embedded generation and associated assumptions are accounted for in the way described in (ii) above. No Demand-Related Capex projects will proceed until the network peak demand, inclusive of any embedded generation forecast, increases to a point where network capacity, inclusive of embedded generation, is insufficient to safely and reliably supply the demand.

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

Permanent demand reduction associated with a non-network option is not added back to the demand of the zone substation. It is considered business as usual once implemented. Temporary demand reduction, such as load curtailment and embedded generation, is added back to the peak demand only for the days it was active to determine the true peak.

Where Endeavour Energy implements a non-network program for peak demand reduction no Demand-Related Capex projects will proceed until the network peak demand increases to a point where network capacity, inclusive of non-network solutions, is insufficient to safely and reliably supply the demand. Therefore, the assumptions on the impact of the demand levels are:

- the non-network solution will deliver the required demand reduction level;
- the demand reduction acquired will target the peak demand on the network; and
- no diversity is to be allocated to the demand reduction level.

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

Future non-network solutions are investigated and implemented in a timely manner and are based on cost-effectively deferring or avoiding the preferred network option. Demand reductions and assumptions associated the non-network option are accounted for in the way described above. No Demand-Related Capex projects will proceed until the network peak demand increases to a point where network capacity, inclusive of forecast non-network solutions, is insufficient to safely and reliably supply the demand and the non-network solution exhausts all avenues for peak demand reduction.

(vi) the diversity between feeders;

Diversity between feeders is taken into account in specific circumstances where it is material. For example, when transferring load between industrial and residential feeders or when planning to double cable a feeder onto the same 11kV circuit breaker.

(s) where Endeavour Energy 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;

Assumed future load transfers, spot loads and growth rates are documented in the summer and winter demand forecast documents.

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

There is no underlying growth assumed in the demand forecast. For many existing substations the underlying growth is negative due to Post-Model Adjustments. Growth is only forecast whether are new connections and spot loads.

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

These assumptions are also documented in individual business cases for major projects where relevant, as well as in the Summer Demand Forecast (refer to Endeavour Energy – 7.01 2018-2027 Summer Demand Forecast – August 2017 – Public). Increase in small scale embedded generation is included in Post Model adjustments.

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

Future Demand-Related Capex projects are based on the current demand forecast which includes embedded generation as describe in (r)(ii) above.

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

Future Demand-Related Capex projects are based on the post model adjustments for micro embedded generation and current demand forecast which includes future committed embedded generation as describe in (r)(iii) above.

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

Future Demand-Related Capex projects have been screened for non-network options in accordance with NER Chapter 5 Part B, Network Planning and Expansion. Any feasible and cost effective non-network option would have been implemented and all potential demand reduction opportunities exhausted prior to implementing the network option as describe in (r)(iv) above. Any permanent demand reductions associated with non-network options are incorporated into the demand forecast.

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

Future Demand-Related Capex projects have been screened for non-network options in accordance with NER Chapter 5 Part B, Network Planning and Expansion. Any feasible and cost effective non-network option would have been implemented and all potential demand reduction opportunities exhausted prior to implementing the network option as describe in (r)(iv) above. Once a non-network option is approved for implementation any future demand reduction is taken into account for future demand forecasts.

(viii) diversity with related substations.

Diversity between substations is taken into account in the forecast documents as both diversified and undiversified values at sub-transmission and bulk supply point level.

17.4 Provide:

(a) evidence that any independent verifier engaged by Endeavour Energy 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

Culter Merz was engaged to review the Endeavour Energy's spatial electricity demand forecast upon which the capital expenditure forecast for augmentation for the 2019 to 2024 regulatory control period are based. The objective of the review was to provide an independent assessment of whether the forecast represent a realistic expectation of future demand on the network and whether the forecasts are an appropriate basis for determining capital expenditure requirements.

The review included:

- Identification of the sectors driving capital expenditure for the 2019 to 2024 regulatory control period;
- An assessment of Endeavour Energy's methodology and assumptions used to prepare its bottom-up forecast; and
- A comparison of Endeavour Energy forecast against the equivalent forecast prepared by the Australian Energy Market Operator.

Cutler Merz specialises in economic analysis and modelling, forecasting, financial modelling, strategic advice, asset valuation and pricing, policy development and regulatory advice.

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

The Cutler Merz final report – Review of Endeavour Energy demand forecasts and basis for spot load growth for 2019 to 2024 regulatory control period, February 2018. Refer to Endeavour Energy – Cutler Merz – 7.04 Review of Demand Forecasts and Basis for Spot Load Growth for 2019-2024 – April 2018 – Public.

18. EFFICIENCY BENEFIT SHARING SCHEME

18.1 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;

As identified in EBSS regulatory template 7.5 of Endeavour Energy – RIN0.03 Final RIN Workbook 5 EBSS – 30 April 2018 – Public Endeavour Energy is proposing to exclude the following categories of opex for the purposes of calculating EBSS:

- debt raising costs;
- demand management innovation allowance (DMIA); and
- movement in provisions.

(b) explain for each cost category identified in the response to paragraph 18.1(a) the reasons for the proposed exclusion.

The EBSS allows costs to be excluded that are not forecast using a single year revealed cost approach. On this basis, we have removed debt raising costs and the demand management innovation allowance (DMIA) from the operation of the EBSS. We believe excluding these costs better achieves the requirements of clause 6.5.8 of the NER.

Provisions reflect liabilities that are uncertain in timing or amount. Changes in assumptions or expectations underpinning these future liabilities may lead to movements in the value of these provisions. Our decision to exclude movements from provisions is informed by the AER’s 2015 final determination and the Australian Competition Tribunal’s 2016 ruling on the matter.

Endeavour Energy accepts that changes in provisions will not be treated as actual opex for EBSS calculations. By excluding movements in provisions we are maintaining a consistent approach to the treatment of accruals towards the EBSS.

19. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

19.1 Provide Endeavour Energy's detailed methodology for calculating the following parameters used in the STPIS;

(a) the SAIDI, SAIFI and MAIFI targets for each supply reliability area;

Refer to Endeavour Energy – 10.07 STPIS Proposal & Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public.

(b) the customer service parameters and targets;

Refer to Endeavour Energy – 10.07 STPIS Proposal & Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public.

(c) daily SAIDI, SAIFI and MAIFI and customer service performance derived from the individual interruption data under paragraph 19.3;

Refer to Endeavour Energy – 10.07 STPIS Proposal & Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public.

(d) the MED threshold derived from the daily SAIDI data;

Refer to Endeavour Energy – 10.07 STPIS Proposal & Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public.

(e) The incentive rates to apply to each supply reliability area.

We propose incentive rates for the reliability of supply component of the STPIS calculated in accordance with clause 3.2.2 of the AER's current STPIS. We consider incentive rates should be based on VCR values reported by AEMO.

Similarly, we support the incentive rates for the customer service component of the STPIS as set out in section 5.3.2 of the STPIS.

Refer to Endeavour Energy – 10.07 STPIS Proposal & Reliability Licence Conditions Compliance Capex Requirement – March 2018 – Public.

Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.

19.2 If Endeavour Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Endeavour Energy must provide, in respect of each adjustment:

(a) the reasons for the adjustment;

No adjustment proposed.

(b) the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and

No adjustment proposed.

(c) the method, basis and empirical data used as justification for the adjustment.

No adjustment proposed.

19.3 Provide the data required in Workbook 1 – Regulatory determination, regulatory templates 6.1 and 6.2.

Refer to Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

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 Endeavour Energy considers the project should be accepted as a contingent project for the forthcoming regulatory control period;

We are proposing one contingent project for the 2019-24 regulatory period – the Western Sydney Airport Growth Area.

The Western Sydney Airport (WSA) at Badgerys Creek is set to open in 2026. As the responsible entity overseeing the project, the WSA Co. has advised that they are assessing electricity supply options to meet the project requirement.

One option is to engage Endeavour Energy to provide them with supply from the distribution network. Should Endeavour Energy receive a firm and formal connection request from WSA Co., significant augmentation of the surrounding distribution network will be needed during the next regulatory control period.

We have identified this project as a contingent project because there remains uncertainty over the need for Endeavour Energy to undertake investment during the 2019-24 regulatory period. The need for investment during 2019-24 will only be known once WSA Co. reveal their preferred supply option.

We wish to make it clear that investment in the shared network in the region surrounding the airport will be required after the 2019-24 period to cater for customer and demand growth in greenfield areas. A decision by WSA Co. to connect to our network will bring forward these required augmentations into the 2019-24 period. The uncertainty of this contingent project is not with the cost (or need to undertake the investment) but rather the timing of these planned works.

We have carefully considered the clauses in 6.6A.1 of the NER which outline the requirements of contingent projects. With regard to these clauses, should WSA Co. announce their preferred option is to source supply from Endeavour Energy's network, the contingent project:

- will be reasonably required to be undertaken during 2019-24 to meet one or more of the capital expenditure objectives;
- has not been provided for in our total capital expenditure forecast for 2019-24;
- reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
- costs will exceed the largest qualifying cost threshold.

By satisfying the criteria in the NER, we believe the Western Sydney Priority Growth Area project should be accepted as a contingent project.

(b) the proposed contingent capex which Endeavour Energy considers is reasonably required for the purpose of undertaking the proposed contingent project;

Our contingent project capex forecast is $61.2m. This is the efficient amount required to undertake the project based on our understanding from WSA Co. of the supply requirements.

(c) the methodology used for developing that forecast and the key assumptions that underlie it;

Refer to Endeavour Energy – 10.32 Western Sydney Airport Growth Area – Contingent Project Business Case – April 2018 – Public.

(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;

The Western Sydney Airport is a nationally significant transformational infrastructure project that will generate significant economic activity, provide almost 28,000 direct and indirect jobs by 2031, and meet Sydney's growing aviation needs.

The airport will be located at Badgerys Creek at the junction of the Western Sydney Employment Area, the Western Sydney Priority Growth Area and the South West Priority Growth Area. This demonstrates that not only is it a significant infrastructure project in its own right, but will also be a focal point for regional growth in Western Sydney.

Badgerys Creek and surrounding areas are largely rural and currently lacks the distribution network infrastructure needed to support the planned airport development. If supply to the airport is sourced through the distribution network, existing network infrastructure cannot support nor sustain the significant increase in demand expected from the project.

With the airport set to open in 2026, new major network infrastructure will need to be built to increase the capability of the surrounding network in order to provide a safe, secure and reliable supply to all customers in the region whist simultaneously catering for the needs of the airport.

It is entirely reasonable, given the date set for the opening, the scale of the construction project and the wider significance to the local, state and national economy, electricity infrastructure arrangements would need to be confirmed reasonably early in the construction phase (i.e. during 2019-24).

On the basis that Endeavour Energy cannot adequately maintain a safe and reliable supply with existing substations and feeders, the contingent project meets capital expenditure objective (1). That is, it would be reasonably required to:

meet or manage the expected demand for standard control services over that period (cl. 6.5.7(a)(1)).

Relying on the existing infrastructure from the shared network is not technically feasible to simultaneously provide the large increase in load demanded from the WSA development and continuing to provide a safe, reliable and secure supply to existing customers.

Failure to invest in augmenting the network would compromise our ability to provide a safe, secure and reliable supply to our customers. We would not be able to meet our jurisdictional reliability performance standards that form part of our licence conditions nor meet the service standards linked to the technical requirements of schedule 5.1 of the NER. The contingent project includes our forecast costs to the shared network required to ensure we can continue to:

comply with all applicable regulatory obligations or requirements associated with the provision of standard control services (cl. 6.5.7(a)(2)).

Furthermore, the safety of the network would also be compromised as, without investment, a number of assets would be increasingly forced to operate beyond their safe operating ratings for prolonged periods of time, increasing the probability of asset failure. Lack of contingent system capacity in the event of asset failure would compound safety and reliability concerns. For this reason, the contingent project would be reasonably required to:

maintain the safety of the distribution system through the supply of standard control services (cl. 6.5.7(a)(4)).

(e) a demonstration that the proposed contingent capex for each proposed contingent project:

(i) is not included (either in part or in whole) in Endeavour Energy's proposed total forecast capex for the forthcoming regulatory control period;

We will undertake significant greenfield augmentation investment during 2019-24. These investments are required to support our forecast of spatial demand, which is mainly driven by strong customer growth in new developments across Sydney's west. These investments are focussed in Priority Growth Areas and are discussed further in Chapter 10 of our Regulatory Proposal.

Our capex forecasts in the Regulatory Proposal only include investments to address identified needs and system limitations that are reasonably certain in timing and cost. We have not included, either in part or in whole, costs that may be needed to cater for the airport development.

Our PIP (Endeavour Energy – 10.16 Capex Listing (PIP) – April 2018 – Public) provides the full listing of projects currently planned between FY19 – FY28. The PIP includes a description of each project and projected capex costs over this planning period. It can be demonstrated that no capex triggered by the WSA development contingent project contributes to our total capex forecast for 2019-24.

We note, irrespective of the supply option chosen by WSA Co., augmentation of the surrounding distribution network will be required to support spatial demand growth. The decision by WSA Co. will determine the timing of this investment. In other words, if the trigger event occurs and the airport connects to the distribution network during 2019-24, the investment will be required in the 2019-24. If the contingent event is not triggered, planned augmentation will occur in future regulatory periods with plans developed using our standard network planning processes.

(ii) reasonably reflects the capex criteria, taking into account the capex factors, in the context of the proposed contingent project; and

The proposed capex for the contingent project reasonably reflects each of the capital expenditure criteria. To summarise, forecast capex for the contingent project:

- is the efficient amount;
- reflects the costs a prudent operator would require; and
- is based on a realistic expectation of the demand forecast and cost inputs;
- required to meet the capital expenditure objectives.

Our forecast is based on the information made available from WSA Co. regarding security of supply requirements and load forecasts. The methodology used in determining the contingent capex amount is consistent with the asset planning framework used to plan and cost network investment included in our proposed capex forecast for standard control services. This framework ensures that proposed capital investment is efficient and reasonably reflects the capex objectives, criteria and factors. Refer to our response in paragraph 4.1(a), (b) and (c) of this notice for further details on how our capex forecasting methods reflect each of these NER requirements.

Maintaining this consistency ensures our contingent project capex reasonably reflects the capex criteria.

(iii) exceeds either \$30 million (\$nominal) or 5 per cent of Endeavour Energy's proposed annual revenue requirement for the first year of the forthcoming regulatory control period, whichever is larger amount.

Our contingent project capex forecast is \$61.2m.

This is larger than the materiality threshold for a contingent project in the 2019-24 regulatory period of \$42.9m. This threshold value is 5% of our 2019-20 ARR of \$859m.

(f) the proposed trigger events relating to the proposed contingent project.

We nominate the occurrence of the following event to trigger the proposed contingent project.

Endeavour Energy receives a firm connection request from WSA Co. (or other entity responsible for the Western Sydney Airport construction) at any time during the 2019-24 regulatory control period for the primary purpose of providing electricity supply to the airport where:

- *the project requires a material amount of shared network augmentation during the 2019-24 regulatory control period;*

- *the capital expenditure is required to meet the capital expenditure objectives;*

- *the capital expenditure for this network augmentation is not included in the capital expenditure forecasts for the ARR for the 2019-24 regulatory control period; and*

- *a successful regulatory investment test for distribution (RIT-D) demonstrating positive net market benefits has been completed.*

20.2 For each proposed trigger event relating to the proposed contingent project referred to in paragraph 20.1(f), demonstrate:

(a) the proposed trigger event is reasonably specific and capable of objective verification;

Our proposed contingent project will be triggered following the receipt of a firm connection request from WSA Co. (or other authorised entity).

We expect to announce WSA Co.'s decision publically (or otherwise confirm their announcement). In order to commence augmentation works to connect the airport to the distribution network, a connection request will need to be formally submitted to Endeavour Energy. Upon receipt, we will be able to produce the connection request to allow verification of the trigger event.

Endeavour Energy – 10.32 Western Sydney Airport Growth Area – Contingent Project Business Case – April 2018 – Public provides a detailed analysis of the network limitations and contingent project requirements. This document, and our responses in question 20.1, ensure the first three conditional points of our trigger event definition have been met.

The final conditional point will be met following the conclusion of the associated RIT-D process, completed in accordance to the AER's RIT-D Applications Guideline.

On this basis, we consider the trigger event to be specific and capable of 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 capex objectives;

Entering into a contractual agreement with Endeavour Energy makes the WSA Co. decision on electricity supply arrangements legally binding. With the airport planned to open in 2026, we consider the proposed trigger will require prompt commencement of the contingent project.

Our response to paragraph 20.1(d) outlines why, following the trigger event, the contingent project would be necessary to achieve the capex 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 network as a whole;

The contingent project will result in an increase in costs required to provide standard control services specifically relating to the airport and is not driven by the condition or event that affects the network as a whole. The proposed trigger event specifies this condition.

(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;

The trigger event is described in clear and simple terms. The event is unambiguous and meets all the requirements of clause 6.6A.1(c) in the NER. On this basis, the occurrence of our proposed contingent event 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 the forthcoming regulatory control period, but the

inclusion of capex 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.

The capex in relation to the trigger event applies to the 2019-24 regulatory period. However, given it is not sufficiently certain that the trigger event will occur at all (in the event WSA Co. elect to source supply from TransGrid), we have not included it in our proposed capex.

Should WSA Co. make an announcement prior to submitting our revised Regulatory Proposal, we will appropriately either incorporate the contingent capex in our total capex proposal, or no longer propose this capex and a contingent project.

20.3 Provide a summary of Endeavour Energy's proposed contingent projects for the forthcoming regulatory control period, including the proposed contingent capex and trigger events for each proposed contingent project in the Workbook 1 – Regulatory determination, regulatory template 7.2.

Endeavour Energy has provided these details in regulatory template 7.2 of Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public.

21. REVENUES FOR STANDARD CONTROL SERVICES

21.1 Provide Endeavour Energy's calculation of the unsmoothed and smoothed revenues for each year of the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of Endeavour Energy's Regulatory Proposal.

Endeavour Energy's calculation of the unsmoothed and smoothed revenues, and prices for the purposes of the control mechanism proposed by Endeavour Energy using the AER's post-tax revenue model are provided in Endeavour Energy – 0.04 Post-Tax Revenue Model – April 2018 – Public.

21.2 Provide details of any departure from the AER's post-tax revenue model for the calculations referred to in paragraph 21.1 and the reasons for that departure.

Endeavour Energy has not proposed any departure from the AER's post-tax revenue model for the calculations referred in paragraph 21.1.

22. INDICATIVE IMPACT ON ANNUAL ELECTRICITY BILLS

22.1 For the purposes of calculating the impact of Endeavour Energy's Regulatory Proposal on the annual electricity bill of typical residential and business customers in New South Wales, provide the data/information required in Workbook 1 – Regulatory determination, regulatory template 7.6. Provide the data source for each input used for the calculation.

Endeavour Energy has provided, in Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public, the data/information required in regulatory template 7.6. Refer to Endeavour Energy – RIN1.25 Indicative Bill Impact – Data Sources – April 2018 – Public for the data sources.

23. PROPOSED TARIFF STRUCTURE STATEMENT

23.1 Provide the model(s) used to calculate the long run marginal cost estimates in Endeavour Energy's proposed tariff structure statement provided in accordance with the requirements of clauses 6.18.1A(a)(5) and 6.18.5(f) of the NER.

The LRMC Model is provided at Endeavour Energy – TSS0.02 LRMC Model – April 2018 – Public.

23.2 Provide and describe the methodology and assumptions used to prepare the long run marginal cost estimates in paragraph 23.1.

Endeavour Energy's LRMC methodology is outlined in Appendix 6 of the Tariff Structure Statement. Refer to Endeavour Energy – TSS0.01 Tariff Structure Statement – April 2018 – Public.

23.3 Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under paragraph 23.1 and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the forthcoming regulatory control period.

The Reset RIN requires Endeavour Energy to enter the capital expenditure, operating expenditure and demand forecasts used in the calculation of LRMC.

Capital Expenditure
The capital expenditure (capex) forecast used to calculate LRMC is derived from the capex forecast provided in Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public, regulatory template 2.1, tables 2.1.1 and 2.1.7.

In calculating LRMC and populating table 7.7.1, Endeavour Energy undertook a review of the individual capex programs that aggregate to the total capex proposal. Programs deemed to have no impact on LRMC calculations have been excluded, these include programs related to:

- Pilots and trials;
- Power quality;
- Network monitoring; and
- Reliability compliance.

Endeavour Energy has also excluded site purchase and establishment costs for zone substations that do not have corresponding annual expected demand forecasts within the LRMC calculation horizon.

Overheads have been reduced in accordance with the reduction in direct network capex amounts outlined above. For the purpose of completing table 7.7.1, all capitalised overheads have been assumed to be corporate overheads.

There is no direct mathematical relationship that explains the annual variance between regulatory templates 7.7 and 2.1.

Operating Expenditure
The operating expenditure (opex) forecast used to calculate LRMC is not derived from the opex forecast provided in Workbook 1 – Regulatory determination, regulatory template 2.1, tables 2.16.1 and 2.16.2.

For the purpose of calculating opex as it relates to the calculation LRMC, Endeavour Energy has assumed an annual opex amount equal to 2% of the corresponding years capex used in the calculation of LRMC.

The derivation of the 2% figure is provided in the LRMC Model as provided at Endeavour Energy – TSS0.02 LRMC Model – April 2018 – Public. It is a function of opex to RAB and the proportion of opex deemed avoidable.

Demand

The demand forecast used to calculate LRMC is derived from the demand forecast provided in Endeavour Energy – RIN0.01 Final RIN Workbook 1 Reset – 30 April 2018 – Public, regulatory template 5.4, table 5.4.1.

The LRMC calculation is based Diversified MW (50% POE) demand.

In calculating LRMC and populating regulatory template 7.7.3, Endeavour Energy has excluded major customer demand as the majority of network costs related to incremental changes to a major customer's demand are funded by that major customer directly.

24. REGULATORY ASSET BASE

24.1 Provide Endeavour Energy'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.

Endeavour Energy has calculated 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.

Refer to Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public.

24.2 Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred to in paragraph 24.1 and the reasons for that departure.

We have adopted a new asset tracking approach for depreciation purposes. This applies to all new assets added to the RAB from July 1, 2014. This is discussed in further detail in paragraph 25.

This change in methodology has impacted our RAB calculations referred to in paragraph 24.1 and is reflected in Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public.

Beyond this, Endeavour Energy has not departed from the underlying methods in the AER's roll forward model.

24.3 If the value of the regulatory asset base 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.

We have not proposed to adjust the value of the regulatory asset base as at July 1, 2019 (the start of the next regulatory control period) to account for changes in the asset service classification.

Service classification changes between regulatory control periods as detailed in the AER's framework and approach paper are relatively minor and do not relate to standard control services that would require us to make adjustments to the RAB.

24.4 Provide details of any departure in the allocation of actual capex, asset disposal and customer contribution values across asset classes in the roll forward model from those reported in the Annual Reporting RIN for the relevant regulatory years and the reasons for that departure.

The allocation of actual capex, asset disposal and customer contribution values across asset classes is consistent between the RFM and those reported in the Annual Reporting RIN.

25. DEPRECIATION SCHEDULES

25.1 Provide Endeavour Energy'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; and

The roll forward model has been completed for the current regulatory period and has been included at Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public.

(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.

The post-tax revenue model has been completed for the current regulatory period and has been included at Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public.

25.2 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 paragraph 25.1 and the reasons for that departure.

Endeavour Energy has calculated the depreciation amounts using the straight-line depreciation method as employed by the AER's RFM and PTRM. To depreciate assets, the models require us to establish the remaining standard lives of existing network assets.

In previous Regulatory Proposals, we have adopted the AER's preferred Weighted Average Remaining Life (WARL) method for calculating the remaining lives of our assets. Capex incurred since the commencement of the current regulatory control period has been recognised in separate asset groupings. The WARL for existing asset classes is therefore the WARL approved by the AER less five years.

The separate tracking of capex:

- presents a more accurate method of estimating depreciation;
- ensures total depreciation (in real terms) equals the initial value of the assets;
- results in a depreciation schedule with a profile that more accurately reflects the deteriorating nature of assets in service; and
- has been proposed by several other DNSPs in their respective Regulatory Proposals and subsequently accepted by the AER.

Both the RFM and PTRM have been appropriately adjusted to account for changes to calculating remaining asset lives. Further details on the rationale for this departure can be found in Chapter 8 of our Regulatory Proposal.

25.3 Identify any changes to standard asset lives for existing asset classes from the previous determination. Explain the reason(s) for each change and provide supporting information.

There have been no changes to the standard lives for existing asset classes between the current and forecast regulatory control periods.

25.4 Identify any changes to new asset classes from the previous determination. Explain the reason(s) for using these new asset classes and provide supporting information on their proposed standard asset lives.

There are no new asset classes proposed for the forthcoming regulatory control period.

25.5 If any 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 supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.

No asset classes have been discontinued between the current regulatory control period and the forthcoming regulatory control period.

25.6 Describe the method used to depreciate existing asset classes as at 1 July 2019 (the start of the forthcoming regulatory control period) and provide supporting calculations, if the approach differs from that in the roll forward model.

The process for depreciating existing standard control service assets as at 1 July 2019 can be divided into 2 parts:

Existing assets as at 1 July 2014 – these assets are collectively depreciated according to their asset class using previously determined remaining asset lives.

Assets added to the RAB between 1 July 2014 and 30 June 2019 – these assets are depreciated separately (i.e. not combined with assets existing prior to 1 July 2014) over their standard lives.

Refer to Chapter 8 or our Regulatory Proposal for further details on our depreciation approach. The RFM is provided as an attachment (Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public) to our Regulatory Proposal and demonstrates how both of these methods were applied to derive an opening RAB value for 1 July 2019. We propose to use the same method to calculate asset depreciation over the 2019-24 regulatory period.

Over time, we expect to apply the latter approach to all assets as the remaining life for assets existing as at 1 July 2014 gradually diminishes and ultimately expires rendering the former depreciation method obsolete.

26. CORPORATE TAX ALLOWANCE

26.1 Provide Endeavour Energy'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.

Refer to Endeavour Energy – 0.04 Post-Tax Revenue Model – April 2018 – Public for further details.

26.2 Provide details of each departure from the AER's post-tax revenue model for the calculations referred to in paragraph 26.1 and the reasons for that departure.

Endeavour Energy has not proposed any departures from the AER's post-tax revenue model for the calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period.

26.3 Identify each change 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.

As per the details provided in Schedule 1 response to the Annual RIN for the 2015-16 and 2016-17 financial years Endeavour Energy has identified that two asset classes show a material variation (above 5%) in the standard tax life assessment using our fixed asset register data.

The asset classes contained in the AER PTRM generally consist of several individual fixed asset register asset classes that often have different economic and tax lives. For this reason the standard and remaining tax lives within the PTRM are a weighted average of the underlying asset classes.

As a consequence, any investment in (or retirement of) assets that are not aligned to the existing weightings across asset classes can result in immaterial variance year to year. With this in mind, Endeavour Energy has applied a materiality threshold of 5% variance in the weighted average tax standard asset lives for the purposes of compliance with this obligation.

Endeavour Energy undertook a review of the tax standard asset lives considering the current weighting and composition of the underlying asset classes currently held using the most recent advice from the ATO.

As a result of this analysis two asset classes within the PTRM issued by the AER in April 2015 would appear to have tax standard lives that require updating. The table below sets out the existing PTRM tax standard asset lives, an updated view of the tax standard asset lives and the percentage variance between the two as demonstration of the materiality.

PTRM Asset Class	PTRM Tax Standard Lives	Updated Tax Standard	Percentage Variance
Furniture, fittings, plant and equipment	8.6	7.2	-16.8%
Information & Communication Technology	2.9	4.9	67.8%

26.4 Describe the method used to depreciate existing asset classes as at 1 July 2019 (the start of the forthcoming regulatory control period) for tax purposes and provide supporting calculations, if the approach differs from that in the roll forward model.

As discussed in sections 25.2 and 25.6, we have adopted a new detailed asset tracking approach to more accurately report asset depreciation. The depreciation of assets added to the RAB from July 1, 2014 are tracked separately from assets added to the RAB before this date.

Further details are provided in Chapter 8 of our Regulatory Proposal.

We have also adopted this approach in depreciating assets for tax purposes. This approach is reflected in the RFM. Refer to Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public.

26.5 Provide Endeavour Energy's calculation of the tax asset base for the relevant 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.

Refer to Endeavour Energy – 0.05 Roll Forward Model – April 2018 – Public for further details.

26.6 Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred to in paragraph 26.5 and the reasons for that departure.

There are no departures from the underlying methods in the AER's roll forward model for the calculation referred to section 26.5.

26.7 Identify each difference 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 the capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes.

27. RELATED PARTY TRANSACTIONS

27.1 Identify and describe all entities which:

(a) are a related party to Endeavour Energy and contribute to the provision of distribution services; or

(b) have the capacity to determine the outcome of decisions about Endeavour Energy's financial and operating policies.

Edwards A Pty Ltd as trustee for Edwards A Trust, Edwards O Pty Ltd as trustee for Edwards O Trust and Edwards U Pty Ltd as trustee for Edwards U Trust respectively hold a 50.4% share in each Partnership (Private Partners).

The State holds a 49.6% interest in each Partnership through a number of ERIC subsidiary entities (ERIC Partners).

The Private Partners and ERIC Partners have entered into a partnership deed for each of the Asset Partnership, Operator Partnership and Unregulated Partnership to govern the management and operation of the respective Partnerships.

27.2 Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 27.1.

A diagram of the group structure is provided at Endeavour Energy – RIN1.08 Group Structure – December 2017 – Public.

27.3 Identify:

(a) all arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 27.1 currently in place or expected to be in place during the period 2017-18 to 2023-24 which relate directly or indirectly to the provision of distribution services; and

Nil.

(b) the service or services that are the subject of each arrangement or contract.

Not applicable.

27.4 For each service identified in the response to paragraph 27.3(b):

(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 Endeavour Energy and the relevant provider;

Not applicable.

(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 Endeavour Energy itself;

Not applicable.

(ii) whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement (or similar);

Not applicable.

(iii) whether the services were procured on a genuinely competitive basis and if not, why; and

Not applicable.

(iv) whether the service (or any component thereof) was further outsourced to another provider.

Not applicable.

28. VEGETATION MANAGEMENT COMPLIANCE

28.1 Provide compliance audits of vegetation management work conducted by Endeavour Energy during the current regulatory control period.

Copies of compliance audits of vegetation management work conducted by Endeavour Energy during the current regulatory control period are attached as follows:

- Endeavour Energy – RIN1.10 Audit Report – Vegetation Management – June 2009 – Confidential;
- Endeavour Energy – RIN1.11 Audit Report – Vegetation Management – September 2010 – Confidential;
- Endeavour Energy – RIN1.12 Audit Report – Vegetation Management Follow Up Review – June 2012 – Confidential;
- Endeavour Energy – RIN1.13 Audit Report – Vegetation Management – June 2014 – Confidential;
- Endeavour Energy – RIN1.14 Audit Report – Review of Vegetation Management Sourcing Project P1 – October 2014 – Confidential;
- Endeavour Energy – RIN1.15 Audit Report – Review of Vegetation Management Sourcing Project P2 – June 2015 – Confidential; and
- Endeavour Energy – RIN1.16 Audit Report – Vegetation Management – June 2016 – Confidential.

29. CORPORATE STRUCTURE

29.1 Provide charts that set out:

(a) the group corporate structure of which Endeavour Energy is a part; and

A chart that sets out the group corporate structure is provided at Endeavour Energy – RIN1.08 Group Structure – December 2017 – Public.

(b) the organisational structure of Endeavour Energy.

A chart that sets out the organisational structure of Endeavour Energy is provided at Endeavour Energy – RIN1.09 Organisational Structure – December 2017 – Public.

30. FORECAST MAP OF DISTRIBUTION SYSTEM

30.1 Provide a forecast map of Endeavour Energy'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.

Maps of our distribution system are included in Appendix F of our 2017 Distribution Annual Planning Report (refer to Endeavour Energy – 10.06 2017 Distribution Annual Planning Report – December 2017 – Public). These maps segment our network area into regions and include our sub-transmission lines, zone substations and transmission-distribution connection points.

Descriptions and maps showing the locations of new major assets proposed over the 2019-24 regulatory control period are outlined in Chapter 10 of our Regulatory Proposal. The locations of network constraints and proposed new investments are discussed in our Areas Plans. Refer to Endeavour Energy – 10.22 Augex Area Plans – April 2018 – Public.

Detailed maps which segment major substations and feeders into transmission and bulk supply point regions are provided in Appendix A our 2017 Distribution Annual Planning Report (refer to Endeavour Energy – 10.06 2017 Distribution Annual Planning Report – December 2017 – Public). These maps also indicate the location of new major assets planned for construction during the 2019-24 regulatory period.

31. TRANSITIONAL ISSUES

31.1 Provide information on transitional issues (expressly identified in the NER or otherwise) which Endeavour Energy 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 Endeavour Energy; and

(d) how Endeavour Energy considers the transitional issue could be addressed.

Endeavour Energy does not expect any transitional issues that require consideration by the AER in making its distribution determination.

32. AUDIT AND REVIEW REPORTS

32.1 Provide the audit report and review reports as applicable, prepared in accordance with the requirements set out in Appendix C.

An audit report from Ernst & Young of the historical information populated within the relevant Reset RIN Workbooks is provided at Endeavour Energy – RIN0.06 EY Independent Assurance Practitioners Report – April 2018 – Public and Endeavour Energy – RIN0.07 EY – Independent Auditors Report – 30 April 2018 – Public. These have been conducted in accordance with the requirements set out in Appendix C of the RIN.

32.2 Provide all reports from the auditor to Endeavour Energy's management regarding the audit review and/or auditors' opinions or assessment.

All reports from the auditor to Endeavour Energy's management regarding the audit review and/or auditors' opinions or assessment are provided at Endeavour Energy – RIN0.06 EY Independent Assurance Practitioners Report – April 2018 – Public and Endeavour Energy – RIN0.07 EY Independent Auditors Report – 30 April 2018.

33. CONFIDENTIAL INFORMATION

33.1 This clause applies to any information Endeavour Energy provides:

(a) in response to Schedule 1;

(b) in a Regulatory Proposal for the forthcoming regulatory control period (a Proposal);

(c) in a revision or amendment to a Proposal; and

(d) in a submission Endeavour Energy makes regarding a Proposal or a revised or amended Proposal; (together, Endeavour Energy's Information).

33.2 If Endeavour Energy wishes to make a claim for confidentiality over any of Endeavour Energy's Information, provide the details of that claim in accordance with the requirements of the AER's Confidentiality Guideline, as if it extended and applied to that claim for confidentiality.

Endeavour Energy has completed a confidentiality template in accordance with the AER's Confidentiality Guideline and it is at Endeavour Energy – 0.03 Confidentiality Claim – April 2018 – Public. Also, in the confidential versions of documents the confidential information has been highlighted in yellow shading and public versions of these documents have also been provided. Electronic documents specify in the filename whether it is "public" or "confidential".

33.3 Provide any details of a claim for confidentiality in response to paragraph 33.2 at the same time as making the claim for confidentiality.

Endeavour Energy has completed a confidentiality template in accordance with the AER's Confidentiality Guideline and it is at Endeavour Energy – 0.03 Confidentiality Claim – April 2018 – Public.

34. COMPLIANCE WITH SECTION 71YA OF THE NEL

34.1 Provide a statement attesting that:

(a) Where any expenditure or cost has been incurred or is forecast to be incurred by Endeavour Energy, as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL:

(i) Endeavour Energy has not included any of that expenditure or cost, or any part of that expenditure or cost, in its reported capital or operating expenditures for a network revenue or pricing determination; and

(ii) Endeavour Energy has not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and

(iii) Endeavour Energy has not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users; or

(b) Where no expenditure or cost has been incurred or is forecast to be incurred by Endeavour Energy, as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL:

(i) No such expenditure or cost has been incurred or is forecast to be incurred.

In accordance with section 71YA of the NEL, Endeavour Energy has not recovered nor proposes to recover from end users the costs (in part or wholly) associated with reviews under Division 3A of the NEL in either the current or future regulatory control periods.

Expenditure or costs (actual and forecast) related to recent limited merits and judicial review processes have not been included our forecast expenditure for the 2019-24 regulatory period. We have appropriately excluded these costs from in any way influencing the basis of forecasting our revenue requirements in 2019-24.

Proposed CESS and EBSS penalties/rewards have excluded the impact of these costs.

35. IDENTIFICATION OF CERTAIN COSTS IN ACTUAL CAPITAL AND OPERATING EXPENDITURE

35.1 For any actual capex or opex reported in response to this notice, identify any part of that expenditure which can be attributed to any expenditure or cost that Endeavour Energy has incurred as a result of, or incidental to, a review under Division 3A – Merits review and other non-judicial review – of the NEL.

All costs incurred as a result of (or incidental to) the merits and judicial reviews relating to the AER's 2015-19 regulatory determination have been reported as operating expenditure in the corporate overhead category.

These costs were incurred over three years between 2014-15 and 2016-17. We have excluded these costs from determining actual opex for EBSS purposes, thereby removing their impact in calculating EBSS carryover payments. Refer to Endeavour Energy – RIN0.03 Final Workbook 5 EBSS – 30 April 2018 – Public.

No such costs will be incurred during the 2017-18 base year and therefore have not been factored into our opex forecast for 2019-24 through the opex model.