REVISED REGULATORY PROPOSAL TO THE AUSTRALIAN ENERGY REGULATOR

DELIVERING BETTER VALUE

1 JULY 2014 – 30 JUNE 2019

Endeavour Energy

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This revised regulatory proposal ("revised proposal") sets out the revisions that Endeavour Energy has made to its regulatory proposal in light of the Australian Energy Regulator's ("AER's") draft determination for the period 1 July 2014 to 30 June 2019. Improvements in capital and operating efficiencies have been incorporated, while operating and maintaining the network safety and reliably in the short and the long term interests of consumers.

Since the AER's determination in 2009, Endeavour Energy has proactively and continuously improved the efficiency of its capital and operating programs to deliver savings for customers. Our efficiency gains for the five years to June 2014 were boosted in July 2012 by the implementation of the NSW Network Reform program, which prioritised the progressive improvement in employee and public safety, network reliability and customer affordability aligning with the long term objectives of consumers.

Improvements in capital and operating efficiencies of $296 million already delivered by Endeavour Energy during the 2009-14 regulatory period are progressively reducing the burden on families and businesses through real reductions in electricity network charges and these benefits will continue to flow into the future.

This revised proposal, in response to the AER's draft determination, incorporates further improvements for the five years to June 2019. Our priorities continue to align with the long term interests of consumers to achieve efficiency improvements in capital and operating programs while maintaining a safe and reliable network consistent with the National Electricity Law (NEL) National Electricity Objective (NEO), National Electricity Rules (NER or Rules) and other legislation including the *Work Health and Safety Act*, the *Fair Work Act*, *Corporations Act (Cth)*, the *NSW State Owned Corporations Act* and NSW Electricity Regulations.

Our revised proposal promotes the NEO for the reasons set out in this Executive Summary and promotes the NEO to a greater degree than the AER's draft determination for the reasons set out in the section below titled "Critique of AER's draft determination".

Highlights of our revised proposal

The highlights of this revised proposal are:

- A network that is designed to deliver the NSW Government's mandated customer reliability levels, including average customer supply availability of 99.98% per annum for urban customers.
- Real reduction in forecast average distribution network charges of 0.5% by the end of the 2014-19 period for customers, which results in a level that is sustainable and avoids future price shocks.
- Forecast capital and operating programs for the 2014-19 period that are $1.6 billion (49% less[1]) and $1.4 billion (3% higher[2]), respectively, in real terms than the AER approved forecast amounts for capital and operating programs in the 2009-14 period. Additional vegetation management costs to manage bushfire, public safety and reliability risk are driving the real increase in the operating program.
- Forecast annualised labour productivity improvements of 21.6% by the end of the regulatory period.
- The adoption of Light Detection and Ranging (LIDAR) technology in bushfire prone areas has substantially improved the detection of vegetation encroachment and network defects that must be addressed to mitigate public safety and bushfire risks.
- We propose sufficient revenue to facilitate a financially sustainable business.

[1] For comparison to the 2009-14 period, this calculation includes ancillary network services and metering for the 2014-19 period.

[2] For comparison to the 2009-14 period, this calculation includes ancillary network services and metering for the 2014-19 period.

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A pathway to improved capital and operating efficiency

Endeavour Energy and the AER share a common objective for a safe, reliable and efficient electricity distribution network in the long term interest of customers. Degraded safety performance, deteriorating network reliability and unsustainable network funding are not in the long term interests of consumers and are in conflict with the NEO.

Endeavour Energy and the AER also share an objective to improve the capital and operating efficiency of our electricity distribution network. While that journey is well underway, further improvement is required in the interest of NSW families and businesses.

This revised regulatory proposal submitted by Endeavour Energy provides a pathway for a realistic, progressive and sustainable improvement in capital and operating efficiency while maintaining a safe and reliable network and a return commensurate with regulatory and commercial risk incorporated in the NEL.

The significant elements of this revised regulatory proposal are outlined below:

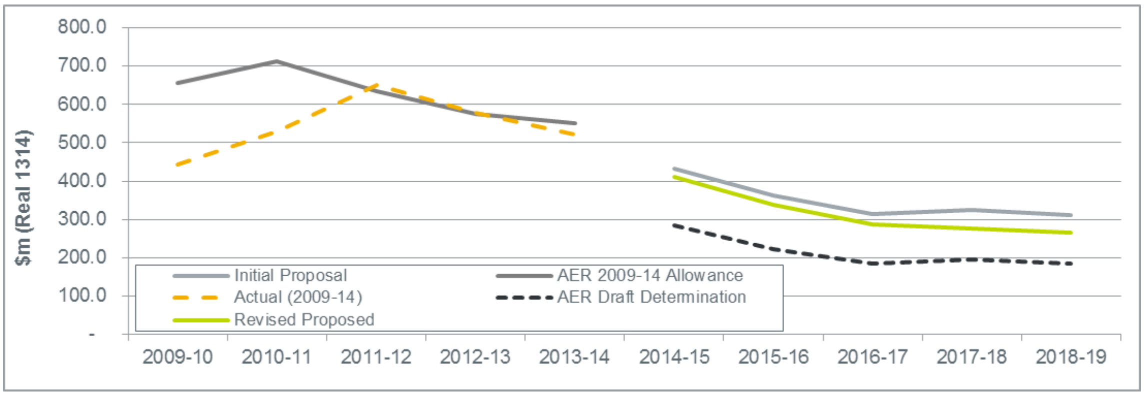
Capital Expenditure (Chapter 5)

Endeavour Energy's revised capital program reflects the following elements:

- A forecast capital expenditure for standard control services that is 49% lower than the amount approved by the AER for 2009-14.
- A forecast capital expenditure for 2014-15 which is within the amount approved by the AER for the transitional year capital expenditure decision.
- A revised capital program for the subsequent four year regulatory period which incorporates a number of aspects of the AER's draft determination and Endeavour Energy's revised and risk assessed capital program.
- An expenditure program that incorporates progressive cost reductions over the next four years through changes to program scope, more efficient project design, improved labour utilisation and reduced unit costs. Together these deliver a program that is 9.7% lower than our initial regulatory proposal (initial proposal).

Figure E1 below sets out the capital expenditure in Endeavour Energy's initial proposal, the AER's draft determination, Endeavour Energy's revised proposal and, for comparative purposes, the forecast capital expenditure program that the AER approved for the 2009-14 regulatory period ($2013-14).

Figure E1: Total capital expenditure – AER allowances, Actual/Proposed – 2009-19



As illustrated above, the forecast capital expenditure amounts contained in this revised proposal are 49% less ($2013-14) than the forecast capital expenditure amounts that the AER approved in respect of the 2009-14 regulatory period and 9.7% less than Endeavour Energy's initial proposal.

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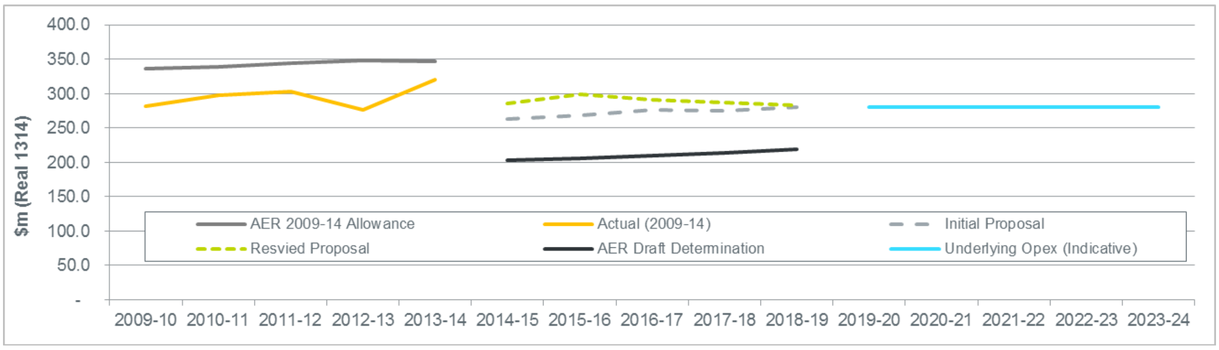
Operating Expenditure (Chapter 6)

Endeavour Energy's revised operating expenditure reflects the following changes and initiatives:

- Forecast progressive improvements in labour productivity which grow to 21.6% by the end of the regulatory period.
- A change in the allocation of some fixed divisional and corporate overheads as a consequence of the reduced capital expenditure program.
- An increase in forecast vegetation costs to reflect the rectification of non compliant clearance levels identified since the introduction of LIDAR technology and consistent vegetation cutting standards in NSW.
- Forecast redundancy costs associated with a progressive reduction in our workforce and required to be paid as a regulatory obligation imposed by an enterprise agreement certified by the Fair Work Commission in accordance with the Fair Work Act. These costs, which are an unavoidable consequence of achieving lower labour costs, will benefit consumers' long term interests by enabling lower total operating costs in future.
- Forecast non labour operating costs have been separately assessed for efficiency improvement opportunities. Contracts for goods and services, including vegetation service contracts, have been escalated consistent with the terms of the contract. Fleet costs have been reduced proportionally with labour productivity improvements.
- Labour cost escalation in line with the AER's draft determination.

Figure E2 sets out the operating expenditure in Endeavour Energy's initial proposal, the AER's draft determination, this revised proposal and the AER approved operating expenditure for the 2009-14 regulatory period ($2013-14).

Figure E2: Operating Expenditure – AER allowances, Actual/Proposed – 2009-19



As illustrated above, the operating expenditures contained in this revised proposal represent a 3% increase ($2013-14) in the five year forecast operating expenditures relative to those that were approved by the AER in respect of the 2009-14 regulatory period and a 6% increase compared to Endeavour Energy's initial proposal. These real increases in the operating program are due principally to additional vegetation management costs to manage bushfire, public safety and reliability risk.

While there are significant and sustainable reductions in operating expenditure associated with labour productivity rates over the 2014-19 period and a reduced capital program, these benefits are moderated by the regulatory obligation to pay redundancy costs associated with driving improvements in labour productivity. As illustrated in Figure E2 above, the long term interest of consumers is advanced by a reduced capital program and lower operating costs in the medium to long term based on sustainable labour productivity improvement, effective vegetation control and a risk based bushfire management program.

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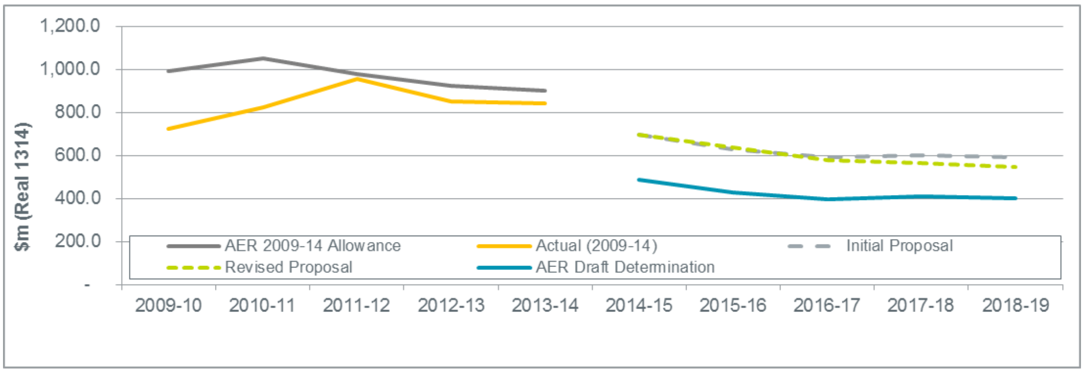
This is reflected by the “underlying opex” line above that illustrates the lower indicative ongoing operating costs in the 2019-24 regulatory period as a result of our efficiency initiatives that are fully reflected once the “one off” transformation costs are incurred.

Total Expenditure

Figure E3 below depicts Endeavour Energy’s total expenditure (capital and operating) for the nominated periods. In real terms ($2013-14), our revised proposal is 30% lower than the 2009-14 programs approved by the AER and 3% lower than what was submitted in our initial proposal.

Figure E3: Total Expenditure – AER allowances, Actual/Proposed – 2009-19



Rate of Return (Chapter 7)

Endeavour Energy proposes a revised rate of return on capital of 8.85%, which is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Endeavour Energy over the 2014-19 regulatory period. The revised rate of return has been developed to promote long term stability both for customers and equity holders.

In summary:

- We propose an allowed cost of debt of 7.98%, which has been calculated consistent with the 10 year trailing average approach set out in the AER’s final rate of return guideline. This estimate is based on bond yield data for BBB+ and BBB rated Australian corporate bonds issued from 1 January 2004 to 31 December 2013.
- The AER has determined that the cost of debt is to be estimated using a ten year trailing average approach that will be subject to annual updates throughout the regulatory period. This position is consistent with the approach in our initial proposal, and as such we accept the AER’s draft decision on this matter.
- We have serious concerns with the AER’s proposed ten year transition path to the trailing average. As Endeavour Energy has historically issued debt on a benchmark efficient staggered portfolio basis, the AER’s debt transition would significantly under compensate Endeavour Energy based on current forecasts of yields on ten year BBB corporate bonds and the cost of our existing portfolio. This results in significant losses being incurred by Endeavour Energy over the entire 2014-19 regulatory period. We consider that the application of the AER’s proposed debt transition would not allow us the opportunity to recover at least our efficient and realistic costs of debt finance, which is inconsistent with the revenue and pricing principles outlined in section 7A of the NEL and should not be applied to Endeavour Energy.
  - The AER’s proposed transition path would mean that the benchmark efficient approach for setting the allowed cost of debt (the trailing average approach) would not be fully implemented for ten years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis.

  - If the AER applied its proposed transition to firms that already issue debt on a staggered portfolio basis, it would by its own measure be setting revenue allowances on an inefficient basis and providing incentives inconsistent with the benchmark efficient approach to debt portfolio management.

- We propose an allowed cost of equity of 10.15%, which is based on internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity has been selected from a reasonable range that takes into account prevailing market conditions and evidence from relevant financial models including the CAPM (both the Sharpe-Lintner and Black versions), the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM).

Endeavour Energy's revised proposal contains an allowed rate of return on capital of 8.85% that is consistent with the approach set out in our initial proposal updated for movements in various market parameters. Chapter 7 outlines our rationale for why the AER should not apply a transition to the trailing average approach for setting the allowed return on debt recognising the benchmark efficient practice and the individual circumstances of Endeavour Energy. Chapter 7 also outlines why the AER's return on equity has not adequately taken account of all relevant data and financial models as required by the NER.

Incentive Mechanisms (Chapter 3)

Endeavour Energy considers that unless the AER accepts our revised capital and operating expenditure proposals, that the Efficiency Benefit Sharing Scheme, the Capital Expenditure Sharing Scheme and the Service Target Performance Incentive Scheme should not apply for the reasons set out below.

Efficiency Benefit Sharing Scheme (EBSS)

- The AER's draft determination states that no expenditure will be subject to the EBSS in the 2015–19 regulatory period. The AER made this decision because of its forecasting approach to opex and the likely incentives Endeavour Energy already faces to improve its efficiency. The AER noted that this also means that no expenditure will be subject to the EBSS in the 2014-15 regulatory period.
- Our contention is that if the AER makes the correct opex decision, it would have no need to suspend the application of the EBSS. The AER's decision is inconsistent with its previously proposed approach. We consider that the AER's reasoning demonstrates that the substitute forecast opex is unachievable, and there would be a high risk of substantial penalties if an EBSS was applied. As we demonstrate in Chapter 6 of this revised proposal, the AER's responsibility is to set an efficient and prudent opex that meets the opex objectives. If the AER make such a decision, then an EBSS incentive would provide a symmetrical incentive.
- If the AER, however, decides to not accept our proposal and to substitute a lower (unachievable) amount, which we consider would be contrary to the NER, then an EBSS would not provide a symmetric incentive (i.e. one in which there is a similar likelihood of achieving rewards or penalties), and therefore should not apply.

In addition, the AER now seeks to exclude carry overs of efficiency gains and losses caused by movements in provisions in the draft decision for Endeavour Energy for the 2015-16 to 2018-19 subsequent regulatory period by claiming that provisions are an accounting treatment and do not actually represent an expenditure (as required by clause 6.5.8(a) of the NER) from which an efficiency gain or loss can be determined. That is, the AER considers that there is a degree of artificiality to such costs. In our view changes in employee related provisions do represent actual costs incurred by Endeavour Energy.

There is no rule that explicitly provides discretion for the AER to retrospectively introduce additional excluded cost categories for the EBSS or to revise/review adjustments, and there are strong arguments that the AER is not entitled to do so.

In addition, the February 2008 EBSS that applied to Endeavour Energy in the 2009-14 regulatory period does not provide for the AER to exclude an additional cost category after the relevant final determination. That is, any decision to exclude an additional category of costs should have been contained in the 2009-14 final determination and not made by the AER after the event.

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We consider firstly that such a retrospective exclusion would be contrary to the purpose of incentive based regulation and secondly would not be consistent with "fair sharing" of efficiency gains and losses under the EBSS. A DNSP cannot be incentivised by retrospective changes to a scheme because the actions that are sought to be incentivised or dis-incentivised have already occurred. Incentives are created by the promise of rewards or penalties. Retrospective changes to either the excluded cost categories or revisions of adjustments made by the DNSPs may instead dis-incentivise DNSPs going forward because there is a risk that the EBSS (or any other regulatory decision) as it is applied to the NSW DNSPs in the future may be different to how the AER represented that the EBSS would apply when it was introduced.

If the EBSS is not applied by the AER in a manner consistent with its previous representation that provisions were not an excluded cost category, then there is a risk that DNSPs will not believe that the AER has the regulatory commitment to keep other regulatory promises. Equally, if revisions of adjustments are made at the end of a regulatory control period, then DNSPs may consider that there is a risk that the AER would review or revise other efficiency gains or losses made. Both of these factors jeopardise the incentive features of the EBSS.

Capital Expenditure Sharing Scheme (CESS)

- The CESS as set out in the AER's November 2013 capital expenditure incentive guideline provides reward/penalty for efficiency gain/loss with respect to capital expenditure. In its distribution determination for the transitional year (i.e. 2014-15), and consistent with the Transitional Rules, the AER specified that no CESS would apply in 2014-15. The AER proposes to apply its CESS in the 2015-19 regulatory control period in accordance with its published guidelines.
- Endeavour Energy's initial proposal was to apply the CESS in the 2015-19 regulatory period, consistent with the AER's proposed approach as stated in the AER's Stage 2 Framework and Approach (F&A) Paper. The AER's draft determination is consistent with the F&A Paper and our initial proposal, and on this basis we have not revised our proposal.
- Consistent with the approach to EBSS, if the AER decides to not accept our capital expenditure proposal and instead substitutes a lower amount, we consider that a CESS would not provide a symmetric incentive (i.e. one in which there is a similar likelihood of achieving rewards or penalties) and therefore should not apply.

Service Target Performance Incentive Scheme (STPIS)

- Our initial proposal agreed with the AER applying a scheme from 2015-16 onwards, and set out a revenue at risk of 2.5%. The AER's draft decision has applied a STPIS from 2015-16 onwards with a revenue at risk of 2.5% consistent with our proposal and the F&A paper. The AER has also accepted our proposed revenue at risk for each parameter.
- However, the AER has not accepted our proposed reliability targets. Attachment 5.04 sets out why we have not revised our proposal for the following changes to reliability parameters. We do not agree with the AER's approach to set a more onerous target compared to our current performance based on an incorrect supposition that investment undertaken in 2009-14 period will have an impact on our targets in the 2014-19 period. Rather the AER should set reliability targets based on our average performance over the last five years.
- In light of the AER's adjustment to our STPIS reliability targets and their proposed real reduction to our future capital and operating expenditure programs of 39% and 23%, respectively, against our initial proposal, we do not consider that we would be in a position to meet our current reliability targets. We have sought advice from Jacobs Group Australia in relation to the reliability and STPIS impacts of the draft determination (Attachment 1.14). Modelling by Jacobs[3] confirmed that in those circumstances reliability would materially worsen compared to previous forecasts, with further degradation in following regulatory periods.

[3] Attachment 1.14 Jacobs, Reliability impact assessment, January 2015, reference Jacobs report.

- A STPIS incentive framework in the 2014-19 period would not provide a symmetric incentive (i.e. one in which there is a similar likelihood of achieving rewards or penalties) and therefore we consider that unless the AER adopts our revised capital and operating expenditure proposals, the STPIS should not apply.

Alternative Control Services (Chapter 8)

We have not accepted the AER's decisions on charges for public lighting, metering services and ancillary network services. As requested by the AER, we have provided additional information to demonstrate we will incur incremental administrative costs that would be appropriately recovered through an administration fee. Further detail is provided in Chapter 8.

Endeavour Energy's Annual Revenue Requirements (Chapter 4)

Table E1 below sets out the revised smoothed annual revenue requirements for Endeavour Energy compared to the AER draft determination and Endeavour Energy's 30 May 2014 initial proposal ($, nominal).

Table E1: Smoothed annual revenue requirements

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Initial proposal	1,021.7	1,021.6	1,046.1	1,067.9	1,101.1	**5,258.3**
AER draft determination	939.9	736.1	754.5	773.4	792.7	**3,996.6**
Revised proposal	949.5	1,058.6	1,092.2	1,123.5	1,167.1	**5,390.8**

As illustrated above, the smoothed annual revenue requirements in this revised proposal are $133 million, or 2.5%, above those forecast in our initial proposal, largely due to increased vegetation management costs as discussed above and in further detail in Chapter 6.

Critique of AER's draft determination

The AER's deterministic use of a flawed benchmarking model in its draft determination for Endeavour Energy has resulted in reductions to submitted operating expenditure of 23%. Endeavour Energy's Chief Operating Officer has signed a statement[4] as part of this revised proposal that he cannot maintain a safe and reliable network based on the AER's draft determination. The AER is accountable for the provision of adequate funds to maintain a safe and reliable network.

The view of the Endeavour Energy Chief Operating Officer as expressed in his statement is as follows:
"In my opinion, based on current information, the reductions proposed by the AER would likely lead to substantial underinvestment by Endeavour Energy in both capex and opex, and would compromise the safety, the reliability and the ongoing sustainability of its network."

In light of the AER's draft decision, Endeavour Energy has made a number of revisions to its regulatory proposal so as to incorporate the substance of changes required to address matters raised by the draft determination or the AER's reasons. We have also incorporated up-to-date information not available at the time of the initial proposal and have reviewed our expenditures to ensure our efficiency programs have been reflected in our expenditure forecasts. These include updates to financial data and the results of LIDAR technology inspections.

There are significant elements of the draft decision that we have not adopted for four key reasons:

[4] Attachment 1.08, COO statement, (Chief Operating Officer of Endeavour Energy)

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1. *Public and Employee Safety (Chapter 1)*

The Draft Determination did not include a safety risk assessment of the potential for increased network asset / system failures as a result of the proposed reduction in 'resources', or the extent to which these reductions would have adverse risk consequences to the health and safety of workers and members of the public. In making the draft determination, the AER did not have sufficient regard to Endeavour Energy's legislative obligations under the Work Health and Safety Act 2011 (NSW) (WHS Act), in particular to meet the "primary duty of care".

The AER's proposal to accept the safety consequences of higher rates of network asset failure and an increase in local service interruptions (blackouts) is neither consistent with the NEO nor the objectives of WHS legislation. The safety risk assessment undertaken by R2A[5] on behalf of Endeavour Energy found that it is foreseeable that safety risks for Endeavour Energy workers and members of the public will increase from the AER's draft determination where it is proposed that Endeavour Energy's operating and capital expenditure be significantly reduced.

Based on consideration of all factors, we are of the opinion that the proposed operating and capital expenditure allowed for in the draft determination would preclude Endeavour Energy from complying with its obligations under the WHS Act. We are also of the opinion that if the AER is aware of the safety impacts of the proposed operating and capital expenditure allowed for in the draft determination and it makes its final determination allowing for these same levels irrespective of these safety impacts, it will be in breach of its primary duty of care under the Cth WHS Act.

Of particular concern is the reduction in Endeavour Energy's vegetation control program implied by the AER's 23% aggregate reduction in operating expenditure. The Commissioners of NSW Fire and Rescue and NSW Rural Fire Service have both expressed in writing a concern over proposals to substantially reduce this operating expenditure and the possible impact on vegetation management in bushfire-prone areas of NSW and whether detailed risk assessments of the broader impacts of the AER's draft determination have or will be conducted by the AER.

This revised proposal includes an increase in operating expenditure to address non-compliant clearance levels and increased vegetation management requirements to aid Endeavour Energy's bushfire risk mitigation plan, as a result of adopting LiDAR technology. This adjustment was foreshadowed in Endeavour Energy's initial proposal.

2. *AER Approach to Benchmarking is untested and unreliable (Chapters 1 and 6)*

In the draft determination, the AER made retrospective and significant reductions in operating expenditure predominantly driven by the deterministic use of the unreliable, untested and unsafe outcomes set out in the Economic Insights (EI) report dated 17 November 2014. The AER breached its obligations under the NER by failing to publish the first Annual Benchmarking Report by 30 September 2014. This failure delayed the publication of the report by almost two months and resulted in no consultation or engagement with Endeavour Energy on how the AER would use the report to assess (and apparently determine) the forecast operating expenditure. This is unsatisfactory and prejudicial to the interests of Endeavour Energy and inconsistent with the NER.

Further, the AER engaged Economic Insights to review whether Endeavour Energy's opex base year should be adjusted and whether a productivity factor should be applied into the forecast period. Economic Insights did not contact Endeavour Energy to discuss any of the issues, nor did its report to the AER show that it had reviewed our initial proposal.

It is concerning that the AER's draft determination relies heavily on the Economic Insights report to support its reductions to Endeavour Energy's opex and at the same time Economic Insights relies heavily on the AER's draft

[5] R2A: Asset/System Failure – Safety Due Diligence Review. Provided as Attachment 1.09.

determination regarding the operating environment to support its conclusions. That is, both reports are based on unsubstantiated positions.

The Rules require the AER to have regard to benchmarking in making its operating expenditure decision. However, we consider that the way in which the AER has approached benchmarking in our draft determination is not consistent with the rule framework. We consider that the AER has misdirected itself in its pursuit of an econometric benchmarking model to produce an outcome (number) that it could use to derive opex without also undertaking appropriate safeguards in the form of data preparation and testing of modelled results. This has led to a poor decision that is not consistent with the Rules or the NEO.

The Rules require the AER to accept the forecast of required operating expenditure if it reasonably reflects the operating expenditure criteria. The criteria include the costs that a prudent operator would require to achieve the operating objectives and a realistic expectation of the cost inputs required to achieve those objectives. This requires the AER to consider the individual circumstances of the business. To do so, the AER should have used benchmarking to identify areas where further investigation might be warranted. Instead, the AER has used an econometric model as a tool by which to derive base year operating costs. This decision is particularly unwise given the known difficulties of benchmarking within the Australian context – a context known for its very small sample and for its heterogeneity.

The AER has erred in its application of benchmarking in the NSW determinations. It has made two decisions that will have far reaching consequences if they proceed unchecked. The first of the AER's critical decisions was to rely on benchmarking exclusively to set the base year opex for each company. The AER did not, as in previous determinations undertake a detailed assessment of components of opex or commission an engineering review of maintenance programs. Instead, the AER relied on an untested benchmarking regime to mechanistically derive very large adjustments to the base year opex for the NSW and ACT distributors.

The second decision and critical mistake was that the AER did not undertake adequate preparation for the application of benchmarking. The AER did not apply itself in sufficient detail to the consistency of reporting in the RIN or the comparability of international data used in its models. The AER did not appropriately test the models developed or the input variables selected. The AER did not provide sufficient time for peer review of their benchmarking approach and did not undertake any due diligence assessment of the consequence of the recommended reductions.

We believe that the results contained in the Economic Insights report are entirely unreliable and should play no role in the AER's final determinations. The operating expenditure proposed by the AER in its draft determination is unrealistic, does not take account of the revenue and pricing principles in the NEL and is not sufficient to meet Endeavour Energy's regulatory and legally binding contractual obligations.

Endeavour Energy has undertaken expert reviews of the AER's approach, benchmarking model and conclusions. These reviews by Frontier Economics[6], Huegin[7], David Newbery[8], Pacific Economics Group Research[9], Advisian[10] and PWC[11] have provided compelling evidence that the AER's approach and conclusions are unsafe and unreliable.

[6] Frontier Economics: Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW: A report prepared for Networks NSW, Jan 2015. Provided as Attachment 1.03.

[7] Huegin: Huegin's response to draft determination on behalf of NNSW and ActewAGL: Technical response to the application of benchmarking by the AER, Jan 2015. Provided as Attachment 1.02.

[8] David Newbery, Cambridge Economic Policy Associates: Expert report, Jan 2015. Provided as Attachment 1.06.

[9] Pacific Economics Group Research, LLC: Statistical Benchmarking for NSW Distributors, Jan 2015. Provided as Attachment 1.07.

[10] Advisian: Review of AER benchmarking, Jan 2015. Provided as Attachment 1.04.

[11] PWC: Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons, Jan 2015. Provided as Attachment 1.05.

3. *AER has discounted our substantial body of evidence about consumers' preferences (Chapter 2)*

The AER has discounted the substantial body of evidence gathered by Endeavour Energy to assess and test consumer and stakeholder preferences. These preferences form the basis of our five year initial proposal and are the result of Endeavour Energy's consumer and engagement strategy, designed well ahead of the publication of the AER's consumer engagement guideline in November 2013.

The strategy identified discrete consumer cohorts and used multiple methods to gather, assess and record consumers' preferences. It also used well-accepted engagement techniques, including quantitative and qualitative research, face to face deliberative planning workshops with residential and small business consumers, discussion forums with stakeholders, meetings with councils, forums for Accredited Service Providers and an innovative Facebook campaign for social media users.

Three consistent priorities emerged as a result of these multiple engagement initiatives: safety, reliability and affordability. In the interests of transparency, Endeavour Energy's website contains reports on each initiative.

Despite this body of evidence, the AER has largely rejected feedback collected from more than 2,400 Endeavour Energy consumers and stakeholders, electing instead to rely on feedback provided in 21 submissions relating to our initial proposal. Further examination shows many claims in these submissions to be unsubstantiated, incorrect or inconsistent with engagement commissioned by Endeavour Energy before and after our initial proposal was lodged.

In November 2014 Endeavour Energy commissioned further research into customer preferences using a Discrete Choice Experiment – or choice modelling – to gain a better understanding of consumers' willingness to pay for services. A report on the initial findings of this research is provided at Attachment 2.03.[12]

The choice experiment designed by Ipsos Social Research Institute presented a number of scenarios to participants reflecting different network charges and service offerings. These were then rated according to relative acceptability. The results of this research validate previous research and engagement initiatives, which showed that while customers are concerned about price and affordability, the majority are not willing to trade reliability, safety and service for lower charges.

Importantly, a scenario featuring network charges based on the AER's draft decision and relative reductions in service standards due to reduced revenue was rated the second least acceptable for Endeavour Energy customers compared to the other scenarios presented. The report found this outcome indicated that:

> *"…customers are unwilling to sacrifice service offerings (particularly in terms of number and duration of unplanned blackouts and service restoration times) for a large reduction in quarterly network charge."*

The choice modelling research revealed that while price is a key driver for customers' choice of potential service offerings, the model and analysis also clearly revealed that changes in service offerings, especially for the number and length of unplanned blackouts and service restoration times were also key drivers for Endeavour Energy.

These findings provide further insight into consumer preferences, and reinforce the conclusions drawn from earlier engagement initiatives and used to support our substantive revenue proposals.

Finally, the AER's notion of more "regulated blackouts" diminishes the serious responsibility Endeavour Energy has to do all that is "reasonably practicable" for the well being of 17,687 life support customers spread across its network. Under the National Energy Customer Framework, DNSPs have special obligations to ensure that life support customers are provided with information to assist them to prepare a plan of action in case of an unplanned interruption and are given written notice of any planned interruptions.

[12] Ipsos Choice modelling research report, January 2015

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Any view that vulnerable customers would be appropriately compensated for increases in unplanned interruptions by a Guaranteed Service Level payment designed around the frequency and duration of interruptions experienced by an average customer totally undermines the policy purpose of these provisions.

4. *AER's Failure to Comply with the National Electricity Law*

The NEL requires that the AER must take into account the revenue and pricing principles under section 7A of the NEL when exercising a discretion in making those parts of a distribution determination relating to direct control network services. The revenue and pricing principles include the following:

a) A regulated network provider should be provided with a reasonable opportunity to recover at least efficient costs incurred in providing direct control network services and complying with regulatory obligations, requirements or making a regulatory payment (NEL clause 7A(2));

b) A regulated network provider should be provided effective incentives to promote economic efficiency in the investment, provision and use of the network (NEL clause 7A(3)); and

c) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing those services to which the price or charge relates (NEL clause 7A(5)).

The ongoing uncertainty surrounding the deterministic use of benchmarking, the AER's unwillingness to consult with the industry on their benchmarking model and the long term positioning of an "efficient frontier" all add to the regulatory and commercial risks for the majority of electricity distributors operating in the National Electricity Market (NEM). We note that Standard & Poor's Rating Service (S&P) monitors final regulatory outcomes in the sector. We consider that if the AER's final decision fails to provide full and timely recovery of efficient costs and adequate return on capital, it would likely represent a credit risk to the entire sector.

Evidence that the AER has not allowed for a return to Endeavour Energy commensurate with the revenue and pricing principles in the NEL include:

- **The return on capital** - Endeavour Energy's debt management practices are efficient and are consistent with the ten year trailing average approach determined by the AER to be the efficient approach to debt management that would be undertaken by a benchmark efficient entity with a similar degree of risk as Endeavour Energy.

- **The AER's transition to the trailing average** - as outlined in the draft determination results in a cost of debt that is insufficient to cover the debt servicing costs of Endeavour Energy's current debt portfolio. In addition, the AER's cost of equity is at the low end of a reasonable range of returns having regard to alternative models. As discussed below, should the AER's regulatory determination result in a credit rating downgrade below Endeavour Energy's current stand alone investment grade credit rating, unfunded debt servicing costs would be further increased and financial sustainability threatened.

- **Insufficient operating expenditure allowance** - the operating expenditure allowance contained in the AER's draft determination is unrealistic and insufficient to cover Endeavour Energy's labour costs (including voluntary redundancy costs) required to be paid by an enterprise agreement certified under the Commonwealth Fair Work Act. The allowance will not provide efficient funding to meet competitively bid and legally binding contracts for vegetation management, IT services, asset inspection and facilities management.

- **Retrospective "true up"** - the "true up" arising from the AER's April 2014 "placeholder" transitional revenue determination for 2014-15 year is $103 million (12%). The magnitude of this unexpected "true up" required in the last four years of the regulatory period further degrades the funding for the provision by Endeavour Energy of direct control network services for that period and results in regulated revenues that are lower than those deemed by the AER in its draft determination as efficient for the four year period to June 2019. The operating and capital expenditures determined by the AER for this transitional year are largely spent or committed and cannot be retrospectively reduced.

- **Reduction in the capital program** - the AER draft determination contains a $676 million or 39% reduction in the capital program compared to that proposed by Endeavour Energy and a $2.1 billion or 66% real reduction in the program approved by the AER for the 2009-14 regulatory period. A significant reduction in the capital program requires a reallocation of corporate and divisional costs from capital to operating costs in accordance with the Endeavour Energy's Cost Allocation Methodology (CAM) approved by the AER. The accounting effect of this sizeable reduction in the capital program is to increase the operating cost pool. Some corporate and divisional costs vary with activity and can be reduced over time with business restructuring, while other reallocated capital costs are fixed and permanently increase operating expenditure. The AER has made no provision for this consequential increase in operating costs driven by sizeable capital reductions and costed in accordance with the AER's approval of the CAM in May 2014.

- **More onerous STPIS targets** - The AER draft determination proposed more onerous targets for network reliability compared with the five year rolling average from the AER's national STPIS regime and paradoxically reduced the capital and operating expenditure required to deliver this improved target. This element of the draft determination has introduced an asymmetric bonus/penalty scheme and increased the regulatory and commercial risk of providing network services.
- **Transforming our business** - The AER has sought submissions in Endeavour Energy's draft determination on whether a "transition" to the AER's determined benchmarked efficient costs should be allowed and how any transition should be funded. This request is misdirected on a number of fronts:
  - The AER's benchmarking model is immature, unreliable and flawed and its calculation of efficiency is wrong. It should not be used in its current state.
  - The question of who should fund any 'transition' is the wrong question based on a false premise. The AER must determine what it considers to be an efficient allowance for operating and capital expenditure. The AER should satisfy itself that the efficient operating and capital expenditure allowance reasonably reflects the capital and operating expenditure criteria. It is not open to the AER to set an amount that it knows is insufficient for the DNSP to meet the operating expenditure objectives. The question of who should fund a 'transition' does not arise when the AER correctly carries out its decision making under the Rules.
  - The AER has incorrectly formed the view that it is not obliged to look at individual circumstances of a DNSP when it is assessing expenditure proposals. This position is based on an erroneous view of the effect of the AEMC 2012 Rule Change. That Rule change did not remove the requirement of the AER to consider the circumstances of a DNSP. The AER's obligation is to address itself to the opex and capex criteria, which requires proper engagement with the DNSPs proposal and the circumstances set out in that proposal.
  - As part of Endeavour Energy's commitment to improve operating and capital efficiency, we propose progressive and sustainable improvements in labour productivity, including progressive reductions in our workforce. As with the majority of electricity distributors operating in the NEM, Endeavour Energy's Fair Work Commission certified enterprise agreement provides for a payment scale for employees accepting redundancy. Providing funding for legally binding redundancy payments is in the long term interests of consumers because operating costs are permanently reduced.
  - The NEL contains revenue and pricing principles that bind the AER to provide a return to Endeavour Energy commensurate with the regulatory and commercial risks of providing network services and that enables a DNSP to recover "at least its efficient costs". This threshold obligation must be met in the AER's determination.
- **Impact on incentive schemes** - The AER's draft determination used the EI benchmark model to establish an "efficient frontier" for Endeavour Energy's aggregate operating expenditure and then determined 2015-19 expenditure based on that "efficient frontier". This approach removes the need for any incentives to promote economic efficiency provided for in the NEL.

Financial Sustainability (Chapter 1)

Endeavour Energy engaged Standard and Poor's Rating Service (S&P) to assess the financial impact of the AER's draft determination by examining the revenues contained in the AER's draft determination combined with the capital and operating costs as set out in this revised proposal, and our forecast interest costs. The confidential S&P report, provided as Attachment 1.15[13], outlines that under the draft decision revenue scenario, Endeavour Energy's stand-alone credit profile would not be sufficient to support an investment grade credit rating (investment grade is anything above BBB-, below this level is sub-investment grade).[14]

As discussed in a confidential section of Attachment 1.16 from UBS, Endeavour Energy would face significant difficulties when trying to raise debt finance with a credit rating that is sub investment grade, including a higher cost of debt, restrictive covenants, less liquidity and higher hedging costs. The pricing of sub-investment grade bonds in the Australian market results in sub-investment grade companies facing a significantly higher cost of debt than BBB, or BBB+ rated firms. UBS's analysis also suggests that there is very limited liquidity for such bonds in the Australian market. These factors would mean that a sub-investment grade credit rating would significantly impair Endeavour Energy's financial sustainability.

To improve financial sustainability Endeavour Energy would need to move to a significantly lower debt structure. This would require a material equity injection, which would not be a viable proposition for investors who would be asked to commit new funds to an operation generating low or negative equity returns.

The interests of consumers are served where regulatory decisions preserve the incentives for debt and equity capital providers to continue to invest in and support network service providers to provide a reliable, secure and safe service to consumers. In its draft determination the AER directly dis-incentivises debt and equity investors in network service businesses from continuing to invest in the businesses.

Clearly, the credit assessment outcome arising from the AER's draft determination is unsustainable and would seriously and adversely impact Endeavour Energy's financial sustainability. Endeavour Energy's revised proposal would provide sufficient revenues to facilitate a financially sustainable business while the AER's draft determination would not.

Feedback on revised proposal

A key vision underlying this revised proposal is to reflect on the views of our customers when preparing our proposal. Endeavour Energy's customers and stakeholders can provide feedback on this revised proposal through the following channels:

Channel	Details
Email	yoursay@endeavourenergy.com.au
Post	Chief Operating Officer PO Box 811 Seven Hills NSW 1730
Online	www.endeavourenergy.com.au/contactus

Customers can also provide feedback and comments on our proposal to the AER (www.aer.gov.au). Alternatively, customers may also like to contact us via Twitter.com/endeavourenergy.

Endeavour Energy, Ausgrid and Essential Energy have also jointly launched a Facebook page (www.facebook.com/YourPowerYourSay) to engage customers on a wide variety of topics ranging from prices and reliability to vegetation management and street lights. We are also now seeking customer feedback about our regulatory proposals on the joint Facebook page.

your power, your say

[13] Attachment 1.15 "Standard and Poor's Confidential credit assessment – Endeavour Energy standalone credit profile".

[14] See https://www.spratings.com/about/about-credit-ratings/ratings-definitions-faqs.html

1 ABOUT THIS REVISED PROPOSAL

Summary

In many instances, we have revised our initial proposal to address the changes required by the AER. We have not revised our proposal in cases where we have concerns with the validity of the AER's decision making, or where we disagree with the substance of the issues raised by the AER. We have provided information to satisfy the AER of our revised proposal in relation to each constituent decision. We consider that the revised proposal consequently meets the long-term interest of our customers with respect to safety, reliability and price. In contrast, we consider the AER's draft decision if made final would result in adverse safety and reliability outcomes, and seriously and adversely impact Endeavour Energy's financial sustainability.

On 30 May 2014 we submitted our initial proposal to the AER. The AER published its draft determination on 27 November 2014. The Rules provide an opportunity to make revisions to incorporate the substance of any changes required to address matters raised by the AER's draft determination or the AER's reasons for it.

The AER's draft determination identifies each of the constituent decisions it is required to make under the Rules. For the most part, the AER rejected our proposal on each of these constituent decisions. Accordingly we have considered whether revisions are necessary to incorporate the changes required by the AER's draft determination in respect of these constituent decisions, and the reasons underlying these decisions. When reviewing the AER's decision we have sought to consider more up to date information that is now available since submitting our initial proposal in May 2014. We have made revisions to our:

- Proposed service classification proposal, control mechanism and incentive mechanisms.
- Building block proposal for standard control services including forecast opex, capex, allowed rate of return, and other parameters used to derive our revised annual revenue requirement and X-factors.
- Alternative control services proposal for public lighting, metering and ancillary services.
- Arrangements for complying and reporting in our pricing proposals for the 2014-19 period.

While we have made changes to incorporate aspects of the AER's draft decision which are set out in the revised proposal, we have also identified those aspects of our initial proposal that we have not revised in light of the AER's draft determination. In this respect, we consider that the AER has misconstrued its task under the regulatory framework, including the AER's perception that its task is only to determine an 'overall revenue allowance'. The AER's task is to make the correct constituent decision which, if made in accordance with the decision making framework, will provide a revenue stream that meets the NEO.

In terms of the AER's constituent decisions, we consider there are fundamental issues with its decision making process in respect of:

- **Opex** – The AER appear to have misunderstood the functions conferred on it by a Rule change made by the Australian Energy Market Commission (AEMC) in 2012. The AER has applied flawed benchmarking analysis as the primary basis for its decision to reject and substitute our proposal, without adequate consideration of materials provided in our proposal, or adequately addressing other factors in the Rules.
- **Allowed rate of return and gamma** – The AER has adopted a transition approach to setting the allowed return on debt that is inconsistent with the benchmark efficient staggered portfolio approach to raising debt. In addition to this, the AER not had regard to the relevant evidence submitted in our initial proposal on the required return on equity for a benchmark efficient energy network firm. Even based on

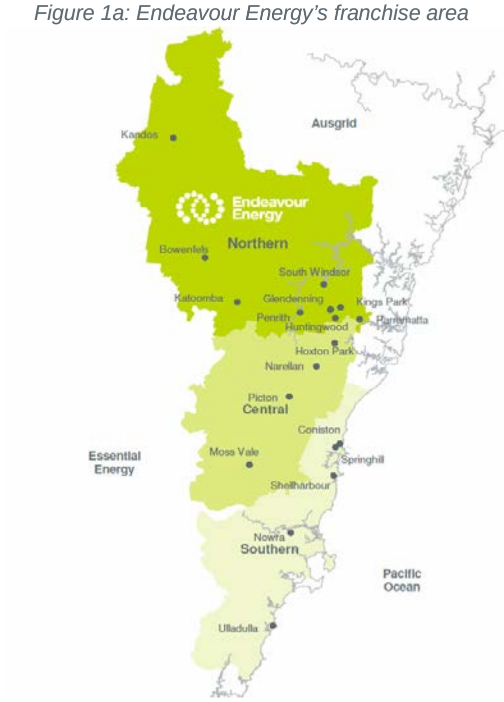
its consideration of a subset of relevant information, the AER has adopted an internally inconsistent approach to estimating the cost of equity within the CAPM.

Overall, we consider that our revised proposal is consistent with the requirements of the NEL and the NER. We demonstrate that our revised expenditure forecasts are the efficient costs and reflect a realistic expectation of cost inputs to achieve the opex and capex objectives. In turn, this provides for the long term interests of customers by providing for safe and reliable services in the 2014-19 period. In contrast, we consider the AER's draft determination would not provide a sufficient revenue allowance to meet our safety and reliability obligations, and would seriously and adversely impact Endeavour Energy's financial sustainability.

1.1. Background and purpose of revised proposal

Endeavour Energy is a New South Wales state owned energy corporation serving some of the largest and fastest growing regional economies in the state. We manage a $5.6 billion electricity distribution network for 926,800 customers, or 2.2 million people, in households and businesses across a network area spanning 24,500 square kilometres in Sydney's Greater West, the Blue Mountains, Southern Highlands, Illawarra and South Coast of NSW.

Figure 1a: Endeavour Energy's franchise area



Our network includes Sydney's North-West and South-West Growth Centres – areas similar to Wollongong and Canberra in size, and earmarked by the NSW Government for current and future housing development. Between them, these centres cover 27,000 hectares and will become home to more than 500,000 people in more than 180,000 dwellings.

In the sections below we provide a summary of our initial proposal submitted to the AER on 30 May 2014, and set out the AER's draft decisions published on 27 November 2014. We then outline the purpose and structure of our revised proposal.

1.1.1 Summary of our initial proposal

As required by the NER we submitted our initial proposal to the AER on 30 May 2014. The AER's draft determination was published on 27 November 2014. The key highlights of our proposal were:

- We proposed a 5.0% reduction in revenue requirements over the five year period covering our initial proposal compared to the 2009-14 regulatory period. This directly translated to an average distribution network price reduction of 1.3% in real terms for a typical residential customer over the five years from 2014-19.
- These real reductions (i.e. less than inflation) were driven by substantially lower capital requirements and operational efficiencies pursued by Endeavour Energy since 2009 and additional efficiencies as a result of network reform program initiatives. They were also a result of lower borrowing costs following the Global Financial Crisis (GFC). We proposed a weighted average cost of capital of 8.83% applied to the 2014-19 period, compared to the rate of 10.02% for the previous regulatory period.
- The five year capital program reduced from $3.0 billion (nominal) approved by the AER for the 2009-14 regulatory period to a proposed $1.9 billion (nominal) for the 2014-19 period – a reduction of 36.0%, which is 43.3% below the forecast rate of inflation over the five year period. The five year operating program increased from $1.6 billion (nominal) approved by the AER for the 2009-14 regulatory period to a proposed $1.8 billion (nominal) for the 2014-19 period – an increase of 9.8%, which is 2.9% below the forecast rate of inflation over the five year period.

- Based on our proposed expenditure plans we expected current network reliability would be maintained for the regulatory period.

A central objective of our proposal was to meet the long term interests of our customers, with respect to safety, reliability and affordability. Electricity networks require prudent maintenance and renewal to deliver a safe and reliable service in the long term. Our proposal used expert engineering judgement and granular budget analysis to identify the efficient level of expenditure and financial returns we require to maintain the health and safety of the network.

Our customer engagement activities played a crucial role in informing our view on what our customers want. The findings indicated a preference for maintaining reliable and safe services, at steady and stable prices. Costs were clearly seen as the most important priority of our customers. With this in mind, our proposal focused on improving customer affordability by incorporating substantial efficiencies into our operating and capital programs for the 2014-19 period, including prioritisation of capital programs. This continued the extensive efficiency gains we had made in the 2009-14 period, where we had implemented cost savings across many dimensions of our business.

The outcome was a proposal that strived to contain average increase in our share of customers' electricity bill to or at below Consumer Price Index (CPI), while maintaining the reliability and safety of the network.

In support of our position, we compiled a detailed and fully substantiated regulatory proposal that complied with the information requirements in the Rules and the AER's RIN. We also demonstrated how our proposal enabled the AER to be satisfied under the criteria in the Rules. For instance, we set out a detailed document addressing the capex and opex decision making objectives, criteria and factors.

1.1.2 AER draft determination

As required under the Rules, the AER published a draft regulatory determination for Endeavour Energy on 27 November 2014. The AER noted that it had turned its mind to the question of what outcome would contribute to the achievement of the NEO to the greatest degree. The AER considered that this occurs where it was satisfied that the decision delivers the best balance between the NEO's factors, including:

- The overall revenue allowance is consistent with the key drivers.
- The constituent components of a potential decision comply with the NER's requirements.

Overall revenue decision

The AER's decision is predicated on a view that recent changes to the NEL and the NER meant that it has greater discretion, and encourages the AER to approach its decision making more holistically to meet overall objectives consistent with the NEO and Revenue and Pricing Principles (RPPs). This led the AER to a view that it must specifically assess its overall revenue decision and its contribution to the NEO.

> *"This is the first draft decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were changed to provide greater emphasis on the NEO and greater discretion to us. The amended NER allows and encourages us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs. These changes also sought to give consumers a clearer and more prominent role in the decision making process.*
>
> *In 2013, the NEL was changed with similar aims in mind. Energy Ministers intend that the long term interests of consumers should be a key focus in determining our decision. The changes also encourage analysis of the decision as a whole in light of the NEO when making constituent decisions.*
>
> *These legislative changes have made this decision different from our previous decisions. In particular, for the first time, we have specifically assessed our overall revenue decision and its contribution to the*

achievement of the NEO. We consider this is an appropriate change as we determine an overall revenue allowance.”[15]

Accordingly, the AER’s overview noted that it made a draft decision on the revenue that Endeavour Energy may recover from its customers in the upcoming 2015–19 regulatory period. In total, the draft decision provides an allowance of $3,056.8 million ($ nominal), which represented a reduction of 27.8% compared to Endeavour Energy's initial proposal.

The AER noted that if it had accepted our proposal, we would have been permitted to recover $4,337.5 million ($ nominal) from customers over the 2015–19 regulatory period. The AER was not satisfied that Endeavour Energy’s proposed revenue would “contribute to the achievement of the NEO to the greatest degree” as it considered was required by the NEL and NER.

The AER stated that Endeavour Energy's regulatory proposal puts forward revenue broadly in line with our current levels. The AER considered that the total revenue it proposed to allow in its draft decision reflected the underlying drivers of the costs of providing distribution services in Endeavour Energy’s network area. Specifically, the AER noted that the circumstances have changed since the last regulatory period such that there has been a material easing in the pressure on costs since it made its last determination in 2009. Consequently, its draft decision provides for less revenue (on average) than what was approved in the last period.

The AER considered that the underlying drivers of the costs of providing network services in Endeavour Energy’s network area are reflected in this draft decision include the following:

- **Efficiency** – The AER recognised that Endeavour Energy has been improving its efficiency for longer than the other two NSW distributors, Ausgrid and Essential Energy. However, the AER considered that its assessment of our proposal showed that there are further opportunities for Endeavour Energy’s network services to be provided more efficiently. It considered that Endeavour Energy itself has identified inefficiencies in its business practices and proposed measures to reduce its costs going forward. The AER referred to its benchmarking work to highlight the extent of efficiencies that it considered were available.
- **Better risk assessment** – In the course of the AER’s review of Endeavour Energy’s proposal it came to the view that Endeavour Energy’s risk management practices are overly risk averse and result in higher capex forecasts than what is necessary.
- **Demand** – The AER noted that at the time of making its last determination in 2009, demand for electricity was expected to increase. However, these forecast increases did not eventuate. The AER noted that system peak demand in Endeavour Energy’s network decreased on average by around 0.05% per annum over the past five years. The AER considered that recent forecasts suggest that the trend will continue downwards, at least for the next few years. The AER noted that this implies that Endeavour Energy is under less pressure to expand its network. These expectations indicate that only modest amounts of growth related expenditure will be required in the forthcoming period.
- **Financial market conditions** – The AER considered that the investment environment has improved since our previous decision. That decision, in 2009, was made at the height of uncertainty surrounding the global financial crisis. Interest rates and risk premiums are now materially lower than in 2009.

The AER’s analysis took these underlying drivers into account and considered that this is reflected in the total revenue allowance it calculated. It stated that the total allowed revenue it determined was broadly in line with the trend in revenue that was allowed in the 2004–09 regulatory period. In 2009, there was a range of pressures that led to a step up in total allowed revenue. The AER noted that the draft decision reflected an easing in many of the underlying drivers that influenced the revenue outcome in 2009. By contrast, it found that Endeavour Energy’s proposal did not adequately incorporate these underlying drivers.

[15] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p16

The AER also noted that it had considered consumer preferences. It stated that stakeholders, including both businesses and consumer advocates, had been telling the AER that Endeavour Energy's proposal did not adequately incorporate their views and is not in the long term interests of consumers.

Constituent decisions

The AER is required to make a number of constituent decisions as part of its distribution determination. It considered that the constituent components of a potential decision comply with the NER's requirements. The AER's constituent decisions were identified in Appendix A of the AER's overview document of its draft determination. It referred to three key constituent decisions it had made:

- **Rate of return** – The AER was not satisfied that Endeavour Energy's proposed 8.83% rate of return is such that it achieves the allowed rate of return objective. It therefore did not accept Endeavour Energy's proposal. Using the AER's rate of return guideline as its starting point, it allowed a rate of return of 7.15% (nominal vanilla) which, in its view, achieved the rate of return objective and will allow Endeavour Energy to fund its efficient network investment.
- **Operating expenditure** – The AER was not satisfied that Endeavour Energy's proposed forecast operating expenditure of $1,384.3 million ($2013–14)[16] reasonably reflected the opex criteria. It therefore did not accept Endeavour Energy's proposal. Its alternative estimate of Endeavour Energy's total forecast opex for the 2014–19 period that the AER is satisfied reasonably reflects the operating expenditure criteria is $1,070.9 million ($2013–14).[17] The main driver for the AER's substitute operating expenditure forecast was its alternative estimate for what they considered represents an efficient base level of operating expenditure.
- **Capital expenditure** – The AER was not satisfied that Endeavour Energy's proposed total forecast capex of $1,746.0 million ($2013-14) reasonably reflected the capex criteria. It therefore did not accept Endeavour Energy's proposal. The AER's alternative estimate of Endeavour Energy's total forecast capex for the 2014-19 period that the AER is satisfied reasonably reflects the capex criteria, is $1,070.4 million. The main driver for the AER's substitute capital expenditure forecast was its reduction in the amount of forecast replacement expenditure.

1.1.3 Purpose and structure of revised proposal

Our revised proposal responds to each constituent decision made by the AER, identifying where we have made revisions to our initial proposal to incorporate the substance of any changes required to address matters raised by the draft determination or the AER's reasons. Where we have not made revisions to our proposal, we consider that this document also comprises a preliminary written submission on the AER's draft determination.

The structure of our revised proposal mirrors our initial proposal including:

- Our customers (Chapter 2) – This chapter does not directly relate to a constituent decision that the AER had to make but is a factor the AER must have regard to in making its decisions on forecast opex and capex.
- Services and Price Control (Chapter 3) – This chapter relates to the AER's constituent decisions on classification of services, control mechanisms, and application of incentive schemes. These were matters the AER had also addressed as part of its F&A papers.
- Building block proposal (Chapter 4, 5, 6 and 7) – These chapters relate to the AER's constituent decisions on our building block proposal for standard control services. This includes each building block and their underlying inputs, revenue and X-factors, and nominated pass through events. Chapter 5, 6 and 7 provide more detail relating to forecast capex, opex and allowed rate of return respectively.

[16] Inclusive of demand management incentive scheme allowance and debt raising costs

[17] Inclusive of demand management incentive scheme allowance and debt raising costs

- Alternative control services (Chapter 8) – This chapter relates to the AER's constituent decision on public lighting, metering and ancillary services.
- Pricing arrangements and negotiated framework (Chapter 9) – This chapter relates to the AER's constituent decisions on compliance with the control mechanisms, reporting arrangements for pricing and negotiated framework.

Each chapter clearly identifies where we have made revisions to our proposal in light of the AER's draft determination and the AER's reasons. Where we have not revised our proposal, the initial proposal (including the relevant supporting documents) remain the current proposal and where appropriate we have provided further support to Endeavour Energy's position and why we have not accepted the AER's draft decision. We note that the supporting documents identified in this document also comprise our revised proposal.

The confidentiality template is at Attachment 1.01 in accordance with the AER's confidentiality guidelines.

1.2. Revisions to address changes required by AER's draft determination

We have reviewed each of the AER's constituent decisions where it has not accepted the position or value identified in our initial proposal. Where we consider that the AER's reasons are appropriate, we have revised our proposal. In the process of reviewing the AER's draft decision, we have also made revisions where new information is available that is relevant in deciding whether to revise our proposal for a matter raised by the AER.

Our revised proposal demonstrates how we satisfy the decision making criteria for each constituent decision the AER is required to make. In this way, we consider that the resultant revenue and prices best meeting the requirements of the NEO to achieve long term benefits to customers and to maintain the safety and reliability of the networks. We have also considered latest information on the efficiencies expected from network reforms in the 2014-19 period, and have incorporated these into our forecasts for the 2014-19 period.

Each chapter of our proposal provides more information on the revisions we have made to our initial proposal.

- Chapter 2 relates to customer engagement activities. We note that customer engagement is not subject to a constituent decision by the AER, but the extent to which our expenditure forecasts includes expenditure to address the concerns of electricity consumers identified during consumer engagement is a factor the AER must have regard to when making its assessment under the capex and opex criteria. However, we have addressed issues raised by the AER in respect of our customer engagement activities, and set out key findings from engagement activities we have undertaken since our initial proposal. Based on what customers are telling us, we do not accept the AER's contention that customers are prepared to trade safety and reliability for a lower price.
- Chapter 3 notes that we have revised our proposal to incorporate the changes required by the AER with respect to service classification and control mechanisms. We have not revised our proposal for the application of incentive schemes. Endeavour Energy considers that unless the AER accepts our revised capital and operating expenditure proposals, that the Efficiency Benefit Sharing Scheme, the Capital Expenditure Sharing Scheme and the Service Target Performance Incentive Scheme should not apply for the reasons set out in the chapter.
- Chapter 4 identifies the revisions we have made to our building block parameters to address matters raised by the AER in respect of the opening asset base, and forecast capex and opex, We have not revised our proposal for the EBSS carry forward for 2009-14 and provide our reasons for this position. We have made consequential revisions to our proposal to our return on and return of capital, corporate depreciation, annual revenue requirement and X-factors to incorporate our revised building block inputs, and to incorporate latest data relating to the allowed rate of return.
- Chapter 5 provides further detail on the revisions we have made to address the changes required by the AER for forecast capex. We have revised our augmentation, replacement and non-system capex to address some of the reasons raised by the AER in the draft determination for rejecting our proposal. We

have also incorporated updated information on the efficiencies we forecast for the 2014-19 period, based on our latest data.

- Chapter 6 provides further detail on the revisions we have made to address the changes required by the AER for forecast opex. We raise fundamental concerns with the manner with which the AER undertook its assessment of opex including its reliance on benchmarking data, which we consider invalidates its draft decision. When reviewing the AER's draft determination we also identified more current data that require revisions to our proposal. We consider that latest data shows that our efficiency programs will have a greater impact on our opex for 2014-19 through higher productivity rates. However latest data shows that our forecasts of the efficient costs of addressing compliance issues with vegetation management standards has increased from our forecast in the initial proposal.
- Chapter 7 provides further information on how we addressed the changes required by the AER on the allowed rate of return. We identify issues with the manner in which the AER has not had proper regard to the current debt structure of Endeavour Energy which we consider reflects an efficient approach to debt management, with the AER's approach to imposing a transition to the trailing average not providing sufficient revenues to meet the requirements of the NEL, NEO and NER. The AER has also not taken account of relevant evidence when setting its return on equity, which is inconsistent with the requirements of the Rules and results in a return that does not adequately compensate equity holders and is insufficient to attract investment in infrastructure assets.
- Chapter 8 sets out revisions to our alternative control services to address changes required by the AER. We have not revised our public lighting proposal for the changes required by the AER, but have made consequential revisions to our proposed prices to incorporate latest data on the allowed rate of return. We have reviewed the AER's changes on metering and ancillary services, and have for the most part not revised our proposal for the changes required by the AER. We have however, accepted elements of the AER's draft determination for metering.
- Chapter 9 notes that we have not made significant revisions to our proposed compliance with control mechanisms and reporting arrangements for pricing purposes in the 2014-19 period to address changes required by the AER. Where appropriate we have raised issues with respect to the technical application of the control mechanism and associated formula.

In many cases we have not revised our proposal to address matters raised by the AER and have provided submissions to support the position set out in our initial proposal. At a high level, our concern has been that certain constituent decisions of the AER's draft determination such as opex and allowed rate of return are inconsistent with the NER and have not led to a decision that satisfies the NEO in the NEL.

In this respect, the AER stated that its decisions for the NSW and ACT NSPs are the first draft decisions that it has made following changes to the NER and the NEL.

> *"This is the first draft decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were changed to provide greater emphasis on the NEO and greater discretion to us. The amended NER allows and encourages us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPP."*[18]

We consider that the AER has fundamentally misconstrued the decision making criteria under the amended Rules and the discretion afforded to it by these changes. We have serious concerns about the AER's construction of the substantive effect of the 2012 Rule change and amendments to the NEL, and hence its application of the amended Rules to Endeavour Energy in its draft determination. There are two key areas where we consider there has been a misdirection in the AER's assessment.

Firstly, the AER has misconstrued the functions it must perform under the NEL and NER. The AER's determination is premised on determining an overall revenue amount, which in its view provides a preferable

[18] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p16

decision that is likely to satisfy the NEO. As discussed in section 1.2.1 below, we consider that the AER is misdirected in applying such an approach to make a draft determination:

- Section 16(1)(d) is predicated upon the existence of two or more decisions that will meet or are likely to contribute to the achievement of the NEO. It is only when this precondition is satisfied that the NEL then requires the AER to make a choice on a decision that achieves the NEO to the greatest degree.
- The AER's approach to setting Endeavour Energy's annual revenue requirement is incorrect. Whilst the total revenue for each year of a regulatory period is a key constituent decision that the AER has to make, the NER is very clear on how this annual revenue amount is to be determined. Most importantly, it is determined by aggregating the key inputs that make up the revenue amount (building block approach) with each input having its own decision-making framework and criteria.

Our second concern is that the AER has not properly carried out its decision making tasks required under the NER with respect to certain constituent decisions including forecast opex and overall rate of return. We have concerns with the validity of the AER's draft decision both in terms of meeting the requirements of the NER, and the substance and merits of its decisions. These concerns are set out in more detail in section 1.2.1 below.

- For forecast opex we are particularly concerned with the AER's application of its benchmarking, which we show cannot be relied upon to set regulatory revenues in a deterministic manner. Further, the AER's failure to publish its first annual benchmarking report in accordance with the requirements of the Rules has severely compromised Endeavour Energy's ability to adequately respond to the outcomes of the report in their revised proposals. The transitional arrangements put in place by the AEMC following the 2012 Rule change clearly contemplate that NSW DNSPs would have a period of two months within in which to consider the AER's first benchmarking report given the timeframes for the regulatory process set out in clause 11.56.4(o) of the Rules and do not contemplate this consideration being done at the same time as preparing a revised proposal.
- For the allowed rate of return, we consider the AER has not made a decision in accordance with the Rules. We outline our concerns fully in Chapter 7.

1.2.1 Concerns with AER's considerations on its role under section 16(1) of NEL

In its draft decision, the AER stated that:

> *"This overview sets out why we are satisfied that our draft decision will contribute to the achievement of the NEO to the greatest degree. Specifically we address section 16 of the NEL which sets out how we must exercise our regulatory functions"*[19]

Below, we set out our consideration on the above views of the AER on the tasks required by the NEL and the NER. In particular, we are concerned about the manner in which the AER has performed its functions under section16(1)(d) of the NEL and with the AER's perception that its task is only to determine an 'overall revenue allowance'. We address these issues below.

Preferable decision

The AER decided to reject the total revenue for the 2015-19 proposed by Endeavour Energy and substituted for an amount that is 29.5% less than that proposed by Endeavour Energy. The AER is satisfied that its substituted revenue amount contributes to the achievement of the NEO to the greatest degree. It also contends that it has done this on the basis of section 16(1)(d) of the NEL which states:

> *"The AER must, in performing or exercising an economic regulatory function or power….*
>
> *If the AER is making a reviewable regulatory decision and there are 2 or more possible reviewable regulatory decisions that will or are likely to contribute to the achievement of the national electricity objective -*

[19] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p14

Make the decision that the AER is satisfied will or is likely to contribute to the achievement of the national electricity objective to the greatest degree (the preferable reviewable regulatory decision)

Specify reasons as to the basis on which the AER is satisfied that the decision is the preferable reviewable regulatory decision."[20]

We considered that the AER has misunderstood its task under the NEL and NER and consequently has not properly carried out this task in accordance with the above requirement of the NEL.

Section 16(1)(d) is predicated upon the existence of two or more decisions that would meet the NEO. It is only when this precondition is satisfied that the NEL then requires the AER to make a choice on a decision that achieves the NEO to the greatest degree. This precondition is clearly recognised by the AER when it stated:

"The NEL anticipates that there may be two or more possible overall decisions that will or are likely to contribute to the achievement of the NEO. In those cases, we must make the decision we are satisfied will contribute to the achievement of the NEO to the greatest degree."[21]

The AER rejected our proposal and substituted this with its own decision. The AER concluded that:

"We are not satisfied that Endeavour Energy's proposed allowed revenue would 'contribute to the achievement of the NEO to the greatest degree' as required by the NER."[22]

The AER then replaced Endeavour Energy's proposed revenue with that calculated by it and then sought to justify this decision as one that would contribute to the achievement of the NEO to the greatest degree. We consider that the AER has misdirected itself as to the nature and purpose of section 16(1)(d) of the NEL or alternatively this section cannot be invoked because the precondition for its application does not exist.

Having rejected Endeavour Energy's proposal as not contributing to the achievement of the NEO, the AER has not identified two or more possible decisions that it considers would or are likely to contribute to achievement of the NEO. Consequently, there is not two or more decisions that achieves the NEO to the greatest degree, a condition that would then necessitate a decision by the AER to choose between one and specify reasons for such choice.

Additionally, instead of identifying two or more decisions that would achieve the NEO for the regulatory period under consideration (i.e. 2014-19) it appears to us that the AER contrasted its substituted revenue allowance decision against the revenue it allowed for the previous regulatory period (i.e. 2009-14) and justified its reasons against the underlying drivers between the two periods. We consider this is an incorrect application of section 16(1)(d) which requires the identification of two or more possible decisions that achieve the NEO for the regulatory period under consideration, and reasons for the choosing one over the other. Section 16(1)(d) does not conceive the task at hand to be one of comparing decisions between periods. This misapplication is apparent in the following AER's statement:

"The total allowed revenue we have determined is broadly in line with the trend in revenue that was allowed in the 2004-09 period. In 2009, there were a range of pressures that led to a step in total allowed revenue. This draft decision reflects an easing in many of the underlying drivers that influenced the revenue outcomes in 2009. By contrast, we have found that Endeavour Energy's proposal does not adequately incorporate these underlying drivers."[23]

Our concerns about the AER's draft decision and justification is further exacerbated by the AER's constituent decisions under Chapter 6 of the NER. As can be seen in the statements below the AER considers that compliance with the NER in relation to 'constituent components of a potential decision' would aid in the finding that a particular decision would be a preferable reviewable regulatory decision.

[20] NEL, s16(1)(d)

[21] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p29

[22] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p9

[23] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, pp9-10

1 ABOUT THIS REVISED PROPOSAL

> *"Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes detailed rules about the constituent components of our decisions, which are intended to contribute to the achievement of the NEO.*
>
> *Consistent with Energy Ministers' views, we consider a decision will contribute to the achievement of the NEO to the greatest degree where we are satisfied that it delivers the best practice between the NEO's factors. To assess this, we especially consider whether we are satisfied that:*
>
> - *the overall revenue allowance is consistent with the key drivers.*
> - *the constituent components of a potential decision comply with the NER's requirements."*[24]

Setting of annual revenue requirement

The AER has not correctly approached its decision making with respect to determining the Annual Allowed Revenue for Endeavour Energy. The AER has taken the mistaken approach that it determines the revenue allowance in some way separately from the constituent decisions which make up that allowance. Endeavour Energy contends that this approach is incorrect and not supported by the Rules.

We are not convinced that the AER has properly carried the tasks required under Chapter 6 of the NEL in relation to the constituent decisions that it must make in a distribution determination for forecast opex and allowed rate of return. We address these issues further below.

At the outset, we note that the AER refers to 'constituent components of a potential decision'. We wish to point out that the distribution determination is predicated upon constituent decisions, each decision with its own decision making criteria. They are decisions on their own which together form the distribution determination, and not components of an overall discretionary decision as seemed to be implied by the AER. Whilst the AER's building block determination is a component of a distribution determination,[25] it is clear that the annual revenue requirement must be determined using the building block approach and each of the building blocks set out in clause 6.4.3 of Chapter 6 of the NER.

> *"These legislative changes have made this decision different from previous decisions. In particular, for the first time, we have specifically address our overall revenue decision and its contribution to the achievement of the NEO. We consider this is an appropriate change as we determine an overall revenue allowance. We do not seek to interfere in the decision a service provider will make about how and when to spend the total capex or opex allowance to run its network."*[26]

We have serious reservations about the views expressed by the AER above. Whilst the decision to approve or refuse the annual revenue requirement for each year of the regulatory period as set out in the building block proposal is a key constituent decision that the AER has to make. The NER is very clear on how this annual revenue amount is to be determined. Most importantly, it is determined by aggregating the key inputs that make up the revenue amount (building block approach) with each input having its own decision making framework and criteria.

We are concerned that the AER has incorrectly carried out its task in determining the annual revenue requirement for us as it is not free to determine 'an overall revenue allowance' but it must, under the Rules, determine this total amount by reference to each of its decision on each key inputs into this amount.

The Rules applicable to Endeavour Energy's 2014-19 regulatory proposal is Chapter 6 of the NER, as amended by clause 11.56.4 which provide certain exceptions to the operation of Chapter 6. More importantly, clause 11.56.4 governs the making of a distribution determination for the subsequent regulatory period (i.e. 2015-19)

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[24] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p29

[25] NER, Clause 6.3.1 .

[26] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p16

except as otherwise specified in that clause. The exceptions concerned mainly with the true up for the placeholder revenue for the transitional year.

Chapter 6 sets out the constituent decisions that a determination is predicated upon. Of note is the requirement for the AER to either approve or refuse to approve the annual revenue requirement as set out in the building block proposal. Clause 6.12.3 deals with the AER's discretion in making a determination.

It states, the AER must approve the total revenue requirements for a regulatory period, and the annual revenue requirement for each regulatory year of the regulatory period, as set out in the DNSP's building block proposal if the AER is satisfied that those amounts:

> *"…have been properly calculated using the PTRM on the basis of the amounts calculated, determined or forecast in accordance with the requirements of part C of chapter 6."*[27]

Part C deals with building block determination for standard control services, Clause 6.4.3 of Part C deals with the calculation of the annual revenue requirement. This clause states that the annual revenue requirement for each year must be determined using the building block approach. The building block approach has a number of elements: including forecast opex, capex and allowed rate of return. Each of the AER's decisions have a specific decision making criteria. For instance the AER's decisions for forecast opex and capex are set out in clause 6.5.6 and 6.5.7 of the Rules.

Also relevant are the matters under 6.10.1 and 6.11.1 which requires that the AER must have regard to the regulatory proposal, written submission and any analysis. These requirements apply to all aspects of the AER's distribution determination. Also relevant is 6.12.2(a)(4) which requires that the AER must set out the basis and rationale of the determination including:

> *"Reasons for the making of any decisions, the giving or withholding of any approvals, and the exercise of any discretion as referred to in this Chapter 6, for the purpose of the determination, such reasons being expressed by reference to the requirements relating to such decisions, approvals or discretion as are contained in this Chapter."*[28]

The effects of these clauses are that:

- The AER must determine the annual revenue requirement for Endeavour Energy for each year of the 2014-19 period based on the building block approach. The building block contains a number of elements.
- The AER must make a separate determination for each of these elements in accordance with the relevant decision making criteria specified in the Rules for each element.
- The AER must explain its decision for each element with reference to the Rules requirements for each decision.

1.2.2 Concerns with the AER's constituent decisions for opex and rate of return

The AER's draft determination comprised a number of constituent decisions. We are concerned that the AER has not properly carried out its task under the decision making criteria for the following material decisions – forecast opex, and the overall rate of return.

We are concerned that the AER has not properly followed the mandatory provisions of the NER in respect of these matters. These concerns are exacerbated by the substance and merits of the AER's decisions. In sum, we have grave concerns on the AER's decision on forecast opex and allowed rate of return with regard to:

- The validity of the AER's draft decision with reference to the requirements of the NER; and

[27] NER, Clause 6.12.3 (d).

[28] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p16

- The substance and merits of such decisions.

We address these issues further in the relevant opex and rate of return chapters. In the sections below, we set out our high level concerns with the AER's decisions. In particular, we outline the substantive effect of the 2012 Rule change. This is critical as the AER has contended that recent rule changes afforded it more discretion and 'make the basis of these decisions fundamentally different from previous decisions'.

Forecast opex

The AER has stated that the changes to the NEL and NER have provided it with greater discretion in terms of its decision making. We consider that this has led the AER to make a decision which has not properly addressed itself to the requirements of the operating criteria, with respect to the opex factors.

In particular, the AER has placed inordinate weight on its benchmarking results, which is only one factor of 11 factors under the Rules. The Rules provide that the AER may have regard to any other factor that it considers relevant. The AER has only considered that elements of its benchmarking analysis are relevant factors. In sum, the AER's decision on forecast opex places undue weight on benchmarking to both reject our forecast opex and as the basis for its substituted opex.

The AER has done so without meaningfully considering other opex factors that should have had significant weight in its decision such as actual and past expenditure, and the incentive mechanisms that applied. Had the AER considered these factors it may have concluded that our opex in the 2012-13 base year was significantly better than the determination the AER had set for the 2009-14 period.

By taking this approach the AER has effectively disregarded its 2009-14 determination which set the efficient forecast opex for Endeavour Energy for the 2009-14 period and the incentive scheme that it applied to Endeavour Energy for this period. It is not sound regulatory practice and therefore it is not reasonable for the AER to effectively ignore its 2009-14 decision and retrospectively redetermine its view of an efficient level of opex, when it has adopted a base year roll forward approach to determining the efficient level of opex. Adopting a base year approach to determining opex, creates an unavoidable link between the 2009-14 decision and the current decision, particularly given the formulaic approach the AER has adopted when applying the base year opex.

The 2009-14 determination made by the AER was the basis upon which Endeavour Energy set its business objectives, operations and management decisions for this period. We fail to comprehend how an actual opex outturn that is below the efficient opex allowance determined under a valid AER's determination can subsequently found to be inefficient, as the AER found in its decision. We note that opex is recurrent in nature and is a sound basis on which to consider the likely efficient forecast opex in the future. This contrasts with other decisions such as capex which is lumpy in nature.

We consider that the AER has placed an inordinate weight on benchmarking analysis due to incorrectly interpreting the discretion it has available under the amended Rule. In order to properly understand and assess the substantive impact of the amendments to Chapter 6 of the Rules with respect to the assessment of proposed forecast expenditure, it is necessary to:

- Compare and contrast the applicable rule provisions before and after the rule change and
- Place the amendment to the Rules in the context in which they were made, particularly the 'problems' with the existing framework that the subsequent amendments were intended to address.

The changes made to the NER in November 2012 were instigated by the AER. The changes proposed by the AER were sweeping, focusing on a range of substantive matters as well as procedural matters. Of the substantive changes, the AER's proposal focuses on the scope of its discretion on a number of key elements of the building block framework, namely the rate of return, forecast capex and forecast opex. In its submission to the 2012 rule change, the AER submitted that the:

"…best way to resolve the issues (perceived by the AER as existing in the previous rules as hindering its ability to determine an efficient expenditure forecast) is to authorise the AER to independently determine forecast costs."[29]

After analysing the 'problems' purported to have existed in the NER, the AEMC concluded:

- Increases in the rate of return and expenditure allowances are both significant factors contributing to rise in network charges. However, some increases in expenditure allowances have been necessary.
- On the basis of the material considered, it is not possible to conclude that the NER have constrained the AER's ability to consider and substitute NSP's expenditure forecasts and have caused inefficient increases in expenditure allowances.
- While the Chapter 6A approach to capex and opex allowances remains generally consistent with good regulatory practice, it could be enhanced in some ways, and some changes for clarification reasons should be made so that Chapter 6 and 6A of the NER better reflect this approach.

As a result, the AEMC determined to make a number of changes to clarify and remove ambiguity in the NER. We consider that the AER has misconstrued the Rule change in a number of respects, which are set out below.

AEMC maintained structure of existing framework

The 2012 Rule change largely maintained the existing framework in the Rules that were applied to making our 2009-14 determination. This included maintaining the structure of the objectives, criteria and factors.

After extensive consultation and analysis, the AEMC essentially rejected the AER's proposed changes to the framework, one that, if accepted, would allow it to unilaterally determine and impose its own forecast expenditure on the NSPs**.** The AEMC stated:

"It is not possible to conclude that the NER have constrained the AER's ability to consider and substitute NSPs' expenditure forecasts and have caused inefficient increases in expenditure allowances.

The Commission confirmed that the NER is drafted appropriately in many areas. With the exception of benchmarking, the capex and opex criteria remain valid.

The AER proposed that the criterion relating to demand forecasts and cost inputs was less than important than the first two criterion and should be moved to the capex and opex factors. The view was taken in the draft rule determination that it would position the demand forecasts and cost inputs as objectives rather than key elements of expenditure allowances that are relevant in a range of ways. The Commission therefore remained of the view that this criterion should remain where it is."[30]

An additional opex factor was inserted in the Rules to allow the AER to consider any other factors that it considers relevant, after having notified the NSPs of this factor in writing before the submission of a revised regulatory proposal.[31]

The insertion of this 'other factor' resulted from the AER's contention that it should be able to raise any other expenditure factor prior to the submission of the revised regulatory proposal. The AEMC accepted that there may be other relevant expenditure factors that may not have been covered within the other expenditure factors in the Rules and consequently allowed the amendment of the NER to include clause 6.5.6(e)(4). It is however, important to note the following analysis from the AEMC when allowing this change:

"The Commission considers that the existing capex and opex factors are sufficiently broad that it should be rare that the AER would need to consider additional factors."[32]

[29] AER, Submission to Directions Paper, April 2012, p12.

[30] AEMC, Economic Regulation of Network Service Providers - Draft Rule Determination, August 2012, p 109 .

[31] NER, Clause 6.5.6(e)(12)

Role of benchmarking

The AER considers that it is sufficient to rely on benchmarking analysis to reject and substitute its determination. The AER states that however, benchmarking analysis is only one factor that the AER must have regard to. Moreover, it is only an expenditure factor, not an expenditure criterion. Its role is to help the AER on whether the proposed forecast expenditure reasonably reflects the expenditure criteria. It neither replace the criteria nor is the sole criterion upon which an assessment of the proposed forecast expenditure is made.

The 2012 Rule change also inserted in clause 6.5.6(e)(4) the reference to 'the most recent annual benchmarking report that has been published under rule 6.27'.

At first glance, it appears to that such amendment as the need for the AER to take into account benchmarking already exists before the rule change.[33] On closer analysis of the context under which this amendment arose, it is clear that the amendment relating to the preparation and publication of an annual benchmarking report fundamentally stemmed from the need to improve information available to customers to better facilitate consumer engagement in the regulatory process. Consequently, clause 6.27 of the NER was inserted to require the AER to prepare and publish an annual benchmarking report in reasonably plain language. This was the primary objective of this change and resulting NER clause.

The AEMC also considered that the annual benchmarking report would assist the AER in assessing a NSP's regulatory proposal. Hence, the opex objective 6.5.6(e)(4) was amended to include the reference to the annual benchmarking report.[34] It is imperative to note that these annual benchmarking reports are but only one of a suite of information that the AER needs to have regard to in making a determination on Endeavour Energy's forecast opex. It does not form the only piece of information and certainly it does not displace the NSP's regulatory proposal.

As noted in Chapter 6, we have sought expert opinion on the AER's application of benchmarking analysis. We have attached the following reports:

- Huegin Consulting Response to Draft Decision on behalf of Networks NSW and ActewAGL - Technical response to the application of benchmarking by the AER (Attachment 1.02)
- Frontier Economics: Review of AER's econometric models and their application in the draft determinations for Networks NSW (Attachment 1.03)
- Advisian: Review of AER Benchmarking (Attachment 1.04)
- PWC: Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons (Attachment 1.05)
- David Newbery Cambridge Economic Policy Associates: Expert report (Attachment 1.06)
- Pacific Economic Group: Statistical benchmarking for NSW Distributors (Attachment 1.07)

Individual circumstances

The AER has not adequately considered our individual circumstances when assessing our proposed opex. The removal of the 'individual circumstances of the NSP's from the opex criteria does not remove the need (and the obligation) for the AER to consider the circumstances of the NSPs given the requirement to accept the forecast operating expenditure that reasonably reflects the operating expenditure criteria. The criteria necessarily involve consideration of the individual circumstances of the businesses as recognised by the AEMC in its final position paper for the final 2012 Rule change.

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[32] AEMC, Economic Regulation of Network Service Providers - Draft Rule Determination, August 2012, p 89.

[33] Clause 6.5.6(e)(4) before the 2012 rule change refers to 'benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period'

[34] AEMC, Economic Regulation of Network Service Providers - Draft Rule Determination, August 2012, p 89.

The phrases 'in the circumstances of the DNSP' appeared in clause 6.5.6(c)(2) of the NER prior to the change. In its rule change request, the AER proposed to delete the opex criteria altogether. Explaining the rationale for its proposed deletion the AER stated that:

> *"Further, it is proposed to delete the criteria relating to the circumstances of the relevant NSP. Good benchmarking practice requires that the characteristics of the individual network be taken into account in the normalisation of the data, including matters such as network topography. However, this is different to taking into account the circumstances of the individual owner of the network. The imprecise language used in the current rules may limit the AER's ability to apply comparative analysis and benchmarking in identifying efficient cost."*[35]

The AEMC agreed to remove this phrase from the opex and capex criteria in the NER. In explaining and clarifying this decision and the intended effect of the removal, the AEMC unequivocally stated that:

> *"The Commission is of the view that the removal of the "individual circumstances" clause does not enable the AER to disregard the circumstances of a NSP in making a decision on capex and opex allowances. Benchmarking is but one tool the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal. Should the phrase remain, it appears that the AER's interpretation of it may restrict it from utilising appropriate benchmarking approaches to inform its decision making. The Commission considers that the removal of the "individual circumstances" phrase will clarify the ability of the AER to undertake benchmarking. It assists the AER to determine if a NSP's proposal reflects the prudent and efficient costs of meeting the objectives. That necessarily requires a consideration of the NSP's circumstances as detailed in its regulatory proposal. Under the first expenditure criterion the AER is required to accept the forecast if it reasonably reflects the efficient costs of achieving the opex objectives. These include references to the costs to meet demand, comply with applicable obligations, and maintain quality, reliability and security of supply of services and of the system. These necessarily require an assessment of the individual circumstances of the business in meeting these objectives. So to the extent that different businesses have higher standards, different topographies or climates, for example, these provisions lead the AER to consider a NSP's individual circumstances in making a decision on its efficient costs."*[36]

It is clear from the above that the removal of the phrase from the operating criteria was to remove any ambiguity that the AER may have perceived to exist or may have attributed to the clause as it existed in the Rules then. The removal does not however displaced the need for the AER to consider the assess the individual circumstances of Endeavour Energy in making a decision on Endeavour Energy's proposed forecast opex for the 2014-19 period. Something that we considered that the AER failed to do.

- The opex criteria (efficient costs, costs of a prudent operator and realistic expectation of demand forecast and costs inputs) still remain the test for the AER in assessing a NSP's proposed expenditure forecast. Equally, these remain the critical criteria for the AER's substituted forecast should the AER decide not to accept the NSP's forecast.
- The expenditure factors are mandatory matters/factors that the AER must have regard to in deciding whether the proposed forecast opex reasonably reflects the expenditure criteria. These factors are of course in addition to the need for the AER to have regard to the NSPs' regulatory proposal, submissions and the AER's analysis. These three matters were previously expenditure factors but have been 'elevated' to matters that the AER must have regard to in making a determination as a whole rather than as specific expenditure factors.

AER must start with a DNSP's proposal

The AER contended that the Rules, as it existed prior to the 2012 Rule change, makes it difficult for the AER to effectively review and assess an expenditure proposal. The AER considers that this is because the Rules allows the NSPs unfettered discretion in the methods and models that the NSPs may use to develop and support the

[35] AER, Rule change proposal for Economic Regulation of Transmission and Distribution network services, September 2011, p107.

[36] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p 107

expenditure forecast. The AER contended that such broad discretion means that the specific details of a NSP's forecasting method remain largely unknown until the submission of the regulatory proposal.

The AER proposed that the Rules be amended to allow it to specify the models and/or methods that a NSP must apply to develop and support expenditure forecasts.[37] The AEMC did not accept such a change to the regulatory framework as proposed by the AER, that is, mandating a forecasting methodology. The AEMC stated:

> *"The Commission accepts that responsibility for developing a NSP's proposal should remain with the NSP. This includes the development of an expenditure forecast in a manner that the NSPs view as appropriate. It is the AER's role to assess the NSP's proposal using any tools it views as appropriate."*[38]

The AEMC, however, considered it important for the AER to receive information on how the NSP propose to develop its forecast expenditure. The AEMC amended the Rules to:

- Introduce the forecast expenditure assessment guidelines into the regulatory framework. This guideline is to outline how the AER propose to assess forecast expenditure proposal. The AER, in its F&A for a particular NSP, will specify how it intends to apply this guideline in the upcoming distribution determination.
- Introduce the requirement that the NSPs must inform the AER of the methodology the NSPs proposes to use to prepare the forecast expenditure that forms part of its regulatory proposal.

Rate of return

The Rules state that the allowed rate of return is to be determined such that it achieves the allowed rate of return objective. The objective is that the rate of return for a DNSP is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service. There are two elements of the AER's draft decision on the rate of return that we consider do not meet the Rules requirements. We consider that this does not enable us to meet the Revenue and Pricing Principles in the NEL.

Transition path to trailing average

We do not agree with the AER's proposed ten year transition path to the trailing average. As Endeavour Energy has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's proposed transition would significantly under-compensate us based on current forecasts of yields on ten year BBB corporate bonds and would not operate to minimise any difference between our return on debt and the return on debt of a benchmark efficient entity with a similar degree of risk as that which applies to Endeavour Energy.

The application of the AER's proposed debt transition is inconsistent with a number of the revenue and pricing principles in section 7A of the NEL. In particular, the AER's proposed transition would not, over the 2014-19 period, provide us with a reasonable opportunity to recover at least the efficient costs of debt finance, nor give rise to prices that would allow for a return commensurate with the regulatory and commercial risks involved in providing direct control network services.

The AER's proposed transition path would mean that the benchmark efficient approach for setting the allowed return of debt (the trailing average approach) would not be fully implemented for ten years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis. If the AER applied its proposed transition to firms that issue on a staggered portfolio basis, it would be setting revenue allowances that are insufficient to cover forecast costs of debt for firms with efficient debt management practices.

[37] AER, Directions Paper Submission, 2 May 2012, page 12

[38] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p 109

Cost of equity

The AER has not had regard to relevant evidence and models that were submitted as part of our initial proposal when setting the allowed return on equity. This is inconsistent with clause 6.5.2(e)(1) if the NER. In addition to this, the AER's draft decision inconsistently applied the risk free rate parameter within the CAPM by using a short term risk free rate in one part of the equation and a long term risk free rate in another part. This is in breach of clause 6.5.2(e)(3) of the Rules which requires that the AER must have regard to any interrelationships between parameters when setting the allowed return on equity.

We consider that the AER should have regard to the following evidence, which is relevant within the meaning of clause 6.5.2(e)(1) of the Rules:

- Fama-French model based estimates of the cost of equity for the benchmark firm.
- Black CAPM based estimates of the cost of equity for the benchmark firm.
- DGM based estimates of the cost of equity for the benchmark firm.
- Empirical evidence of the low beta bias of the Sharpe-Lintner CAPM beta.

Endeavour Energy has considered all relevant evidence and financial models in determining our proposed return on equity of 10.15%. Our point estimate is consistent with a range of relevant estimates that includes a Sharpe-Lintner CAPM point estimate using long term estimates of the Market Risk Premium (MRP) and the risk free rate, a Sharpe-Lintner CAPM point estimate using short term estimates of the risk free rate and the MRP and outcomes from the Black CAPM, Fama-French 3 Factor Model (FFM) and DGM based estimates.

1.3. Why our revised proposal best meets the NEL and NER requirements

As we noted in section 1.2 we consider that the Rules provide for a series of constituent decisions that, if made in accordance with the decision making criteria (having regard to inter-relationships), will provide a revenue stream that gives effect to the NEO. That is, the resultant revenue will promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.

In our initial proposal we provided information to enable the AER to be satisfied with our proposals for each constituent decision in accordance with the decision making criteria in the Rules. Our revised proposal has looked carefully at the AER's draft determination and its reasons for it to assess whether revisions are necessary in light of the AER's findings. In many cases, we have accepted that the AER has identified a valid issue, or has developed a reasonable alternative. In these cases, we have revised our proposal to address the change required by the AER. In other cases, we consider the AER's decision making has not been appropriate, or that the substantive issue raised can be addressed without revisions to our proposal.

Despite the revisions we have made, we note that our revised proposal significantly differs to the AER's draft decision in a number of material respects. Most notably, the AER's draft determination provides a revenue allowance for our standard control services that is 25.6% lower than our revised proposal. This in turn is based on three differences in our constituent decisions:

- Our revised capex is 47.3% higher than the AER's draft determination.
- Our revised opex is 37.4% higher than the AER's draft determination.
- Our revised allowed rate of return is 8.85% compared to the AER's draft determination of 7.15%.

The purpose of this section is to demonstrate that our proposals for each of these constituent decisions better satisfy the decision making criteria relative to the substitutes derived by the AER. In this way, we consider that the resultant revenue better meets the NEO.

In contrast, the AER's draft decision did not address the relevant aspects of the NEO in terms of safety, reliability, quality and security of services. We believe that the AER did not address itself to the capex and opex criteria when making its decision, specifically it has not addressed how its substitute forecasts will enable Endeavour Energy to meet the operating and capital expenditure criteria. Further the AER's decision on an overall revenue requirement that best satisfies the NEO did not clearly identify the safety and reliability implications inherent in providing a significantly lower revenue amount.

Further, in its draft determination the AER has not taken into account the time and resources it takes to deliver transformation in the NSW DNSPs. It takes time to deliver change in the NSW electricity distribution businesses, because it must be done:

- **Safely and Legally** – for our employees and for the public, because of the direct inherent dangers of electricity and its operation, and the secondary risks related to our infrastructure, such as bushfire prevention. This must be done consistent with our operating licence conditions legislated by the NSW Parliament and the federally legislated Fair Work Act that governs the processes surrounding the industrial relations framework under which we must operate our workforce.
- **Affordably** – in a way that minimises the cost of change for the electricity consumers of NSW. Irrespective of whether that cost is borne by our shareholders or our customers, we aim to minimise the cost of change such as to deliver the most efficient outcome for society.
- **Reliably** – as an essential service, we must ensure we are managing the distribution network sustainably, both for now and in the years ahead. This includes having regard for both the technical operation of our assets and the impacts on our workforce given the rights under the Fair Work Act our workforce has for protected industrial action.

Endeavour Energy will fulfil its obligations to its customers, the people of NSW, in a way consistent with these principles. It is possible to reduce costs faster by ignoring these principles, however history has proven that reducing costs faster can have consequences, be it in terms of public safety (see Black Saturday class action settlement of $494m), extended industrial action (see Citipower's 1997 fifteen week industrial dispute), or simply costing more than it should.

It must also be recognised that the assets contained in the electricity network are long lived in nature, and inherently complex. The effective management of these assets must therefore take into account their duration when looking to implement change, and transition to a new operating environment.

Attachment 1.17 sets out the process Endeavour Energy must undertake as it continues to transform to a new capital and maintenance program over the next four years and the exogenous factors that constrain the speed at which transformation can be achieved. Again, the AER has given no regard to the reality of this operating environment in dismissing all restructuring costs.

In the section below, we demonstrate how our revised capex and opex contributes to achieving the safety and reliability of services. We demonstrate that the AER's revenue allowance would not be sufficient to achieve safe and reliable network services in our circumstances. This is set out in section 1.3.1 and 1.3.2 respectively. To this extent we have provided a COO Statement at Attachment 1.08 from our Chief Operating Officer which sets out why the expenditure and proposed allowed rate of return is required to meet the NEO.

Further, we would also not have the financial sustainability to fund our activities, or absorb losses from undertaking unfunded expenditure required to sustain the safety and reliability of the network.

1.3.1 Safety issues

In this section, we identify the safety implications with the AER's draft determination. We rely on the expert opinion of:

- R2A Asset/System Failure: Safety Due Diligence Review (Attachment 1.09)
- AON: Insurance Advice Report - Insurance costs and coverage impacts arising from cuts in vegetation management expenditure for the 2014-2019 regulatory period (Attachment 1.10)
- Commissioner - Fire and Rescue NSW: Letter to CEO of Networks NSW (Attachment 1.11)
- Commissioner - NSW Rural Fire Service: Letter to CEO of Networks NSW (Attachment 1.12)

Public and Employee Safety

Modern society places a high value on the safety of its citizens. Electrical networks are inherently dangerous, and without effective risk management of the network asset, infrastructure and systems there is an increased likelihood of electrical shocks and/or electrocution, asset failure resulting in injury to people and property damage, explosions and bushfires. It is for this reason that we have an ordered priority for a safe, reliable and affordable electricity network.

We strive to continuously improve our safety standards and practices across the electrical distribution network in accordance with NER objectives and the expectations of the public. We prioritise safety to ensure so far as is reasonably practicable, that we do not adversely impact the safety of our workforce and the members of the public in the delivery of reliable and affordable services to our customers and the community.

The capital and operating expenditure amounts in our revised proposal embodies our commitment to the prioritisation of safety. The proposal has been designed to meet Endeavour Energy's legislative obligations under the Work Health and Safety Act 2011 (NSW) (WHS Act), in particular meeting the "primary duty of care."[39]

Endeavour Energy's revised proposal has used recognised risk methodologies and processes to ensure that its obligations in relation to safety are effectively satisfied including the Failure Mode Effects and Criticality Analysis / Reliability Centred Maintenance (FMECA/RCM) process and Endeavour Energy's Portfolio Investment Plan to respectively prioritise both operating and capital expenditure resources relative to risk.

These processes indicate that Endeavour Energy requires $3.0 billion ($ real 13-14) in capital and operating expenditure to safely manage and operate its business.

A failure to allow Endeavour Energy to recover this amount of capital and operating expenditure will lead to increased safety risks due to higher numbers of asset failures with potential fatal consequences to Endeavour Energy employees and the public and would lead to Endeavour Energy breaching its obligations under the WHS Act. The identified network asset failure modes and the foreseeable safety consequences are outlined in sections below.

Public and Employee Safety Implications of the AER's Determination

The AER has demonstrated an alternate view to Endeavour Energy, particularly in relation to safety. In our opinion the AER's draft determination has not reasonably assessed or proposed an acceptable balance between economic costs and the risk to safety, nor has the criticality of these consequences or the potential stakeholder implications been thoroughly considered. It is also our view that the AER draft decision does not provide sufficient revenues to maintain the safety of the system consistent with the achievement of the NEO.

[39] Work Health and Safety Act 2011 (NSW) s19

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The AER's draft determination did not include a safety risk assessment of the potential for increased network asset/system failures as a result of the proposed reduction in 'resources', or the extent to which these reductions would have adverse consequences to the health and safety of workers and members of the public.

The AER stated that its own 'cost modelling and detailed assessments' were used to review the businesses' base operating expenditure efficiency. These detailed assessments included a number of factors, which notably excluded safety.[40] In the same communication it was stated that "Peers in other states are able to provide safe reliable services at lower overall levels of opex."

We disagree with this statement and draw the attention of the AER to recent critical electrical network failure events in other states which have had, or had the potential to, impact the lives and wellbeing of the public.

The Royal Commission into the 2009 Black Saturday fires (VBRC) noted that 173 people had died in the bushfires. The Commission stated:

> *"Victoria's electricity assets are ageing, and the age of the assets contributed to three of the electricity caused fires on 7 February 2009 - the Kilmore East, Coleraine and Horsham fires. Distribution businesses' capacity to respond to an ageing network is, however, constrained by the electricity industry's economic regulatory regime. The regime favours the status quo and makes it difficult to bring about substantial reform. As components of the distribution network age and approach the end of their engineering life, there will probably be an increase in the number of fires resulting from asset failures unless urgent preventative steps are taken.*
>
> *The Commission considers that now is the time to start replacing the ageing electricity infrastructure and to make major changes to its operation and management. The seriousness of the risk and the need to protect human life are imperatives Victorians cannot ignore."*[41]

Similar concerns have been raised with the safety practices and risk management of Western Australian distributors. A parliamentary enquiry into wood poles noted:

> *"Given the potential consequences of any wooden pole failure, wooden power pole safety is, quite literally, a matter of life and death… Over the past 10 years in the south west of this state, there have been as many as 13 bush fire incidents, about which subsequent investigations have suggested that faulty electricity infrastructure may have been the principal cause. This resulted in a tragic loss to the community of three of our fellow citizens. The total loss of property, wildlife and stock as a result of these incidents is not known but is unquestionably extensive."* [42]

In light of these real life examples, we are very concerned with the AER's views that Endeavour Energy's risk management processes are overly risk adverse[43] and that the AER is proposing that Endeavour Energy accept greater risks in terms of higher rates of network failure and consequently increased risks to safety, despite Endeavour Energy's detailed technical optimisation analysis to the contrary.

DNSPs operate to a number of safety standards so that assets remain in good order and notwithstanding, to comply with legislative requirements and in particular their health and safety obligations under the Work Health and Safety (WHS) Act 2011.Therefore resources are required to maintain assets, clear vegetation and renew deteriorating and aged assets and infrastructure commensurate with the business' assessed risk profile in order to protect human life.

For this reason, Endeavour Energy utilises asset related preventative and mitigative maintenance controls (resources) to reduce the likelihood and consequence of hazardous events, particularly those events that have the potential to result in loss of life. In 2013, Endeavour Energy introduced the FMECA/RCM process, to identify

[40] AER Draft Decisions on NSW Electricity Distribution Regulatory Proposals 2015-19, Pre-determination Conference 8 December 2014 Presentation

[41] 2009 Victorian Bushfires Royal Commission Final Report, July 2010 (Parliament of Victoria)

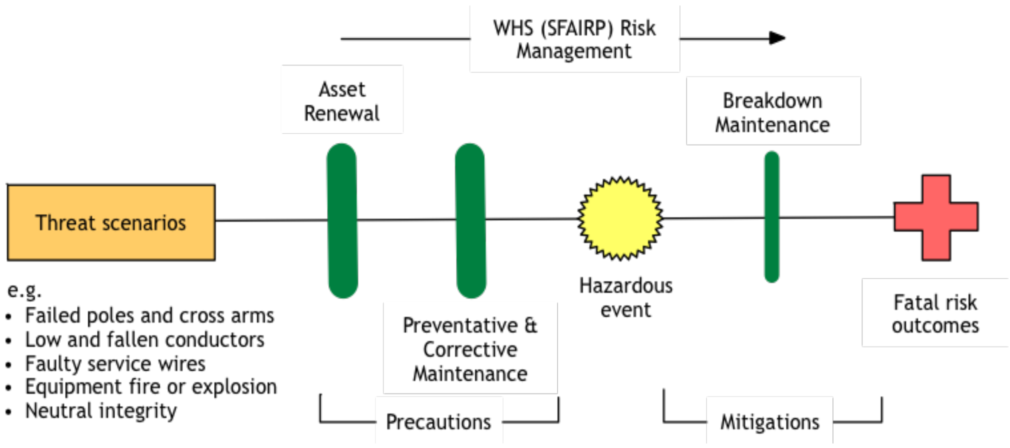
[42] Report 14 Standing Committee of Public Administration, Unassisted Failure, January 2012 (Legislative Council of Western Australian, Thirty-eighth Parliament)

[43] AER Draft Decision Endeavour Energy Distribution Determination 2015-16 to 2018-19, Overview 10

the tasks and activities most cost effective in managing the safety and reliability consequences of the manner in which assets fail (asset failure modes). These tasks or activities may include maintenance, replacement or redesign, or where the individual failure mode does not have an adverse impact on safety and reliability, the methodology allows the option of a 'run to end-of-life' (failure) to be adopted. The application of a quantified[44] FMECA/RCM, coupled with regular reviews of the asset performance data, ensures the task periods calculated for the chosen controls deliver a reasonable balance between both cost and risk for optimal asset performance.

This means that Endeavour Energy utilises objectively determined pre-emptive (preventative maintenance and asset renewals) and planned corrective maintenance as preventative controls to identify and address possible failures before they occur in order to maintain a safe, reliable and sustainable network so far as is reasonably practicable (SFAIRP) in accordance with the hierarchy of controls (HoC) as shown in the diagram below. That is, foreseeable hazards should be eliminated if reasonably practicable, and if this is not possible, mitigated so far as is reasonably practicable.

Figure 1b: Endeavour Energy's hierarchy of controls for fatal risk outcomes



Endeavour Energy disagrees that the AER's draft determination provides a revenue stream within which the business can prioritise its expenditure to adequately manage the safety risks, so far as is reasonably practicable. We consider that the magnitude of the AER proposed capital and operating expenditure reductions in the draft determination, coupled with the retrospective nature for which these will need to take effect, will drive an abrupt and fundamental organisational re-design, reprioritisation of programs and an increase in safety risk to our workers and members of the public beyond the limits that are acceptable.

The impact relative to Endeavour Energy's organisational human resources would require significant and immediate job reductions in the vicinity of 700 representing a 28% reduction in workforce across the organisation. The scope and abruptness of the proposed reduction in a high risk industry could well create a significant human error-inducing factor on a technically specialised and experienced workforce, already implementing efficiency change management programs under the New South Wales (NSW) Government's Reform Program.

A number of Endeavour Energy's prioritised and successful programs are at risk of being identified as discretionary, due to the proposed reduction in operating and capital expenditure. Endeavour Energy's Black Spot Program will fall into this category. There is a public and private interest to reduce motor vehicle collisions and injuries associated with electricity network pole impacts.

Of the three NSW Network Businesses, Endeavour Energy has been the originator of this program investing more than $7 million over the past five years in the relocation of power poles. Between 1998 and 2008 there were

[44] Quantified via algorithms validated by the CSIRO. Ref: Validation of Specified Algorithms in MIMIR, CSIRO Mathematical and Information Sciences, Report CMIS 01/44, 26 March 2001

149 fatalities resulting from motor vehicle collisions and power poles in Endeavour Energy's franchise area (an average of 14.9 fatalities per year). Since the inception of Endeavour Energy's program in 2009-10, a total of 57 rectification projects have been completed. Between 2009-10 and 2013-14 we understand there have been 27 fatalities resulting from motor vehicle collisions and power poles in the Endeavour Energy franchise area (an average of 5.4 fatalities per year). Whilst factors other than Endeavour Energy's black spot program would have contributed to this improvement, this important road safety initiative has been acknowledged by the CEO of Roads and Maritime Services in New South Wales, letter dated 6 January 2015 (Attachment 1.18).

Safety Risk Assessment of the AER's draft determination

The AER does not appear to have sought the advice of WorkCover NSW or the NSW Department of Trade and Investment as to the appropriateness of the proposed capital and operating expenditure allowed for in its draft determination. This is particularly surprising given the level of consultation with Energy Safe Victoria in the Victorian distribution determination 2011- 2015[45] and given the comments in the 2009 Victorian Bushfires Royal Commission:

> *"Protection of human life must become the priority when evaluating distribution businesses expenditure proposals. The economic regulatory regime must include mechanisms for ensuring that safety-related matters are properly reviewed so as to minimise the risk of bushfire being caused by the failure of electric assets."* [46]

Endeavour Energy has commissioned R2A to conduct a safety risk assessment[47] to identify likely network asset/system failures that have the potential for fatal consequences which may arise from implementing the AER's proposed operating and capital expenditure in the draft determination. Please refer to Attachment 1.09 for their report.

The safety risk assessment was completed by R2A within a precautionary due diligence risk management framework consistent with the WHS Act. The approach taken by R2A has been used in a number of studies and was expressly used in the report[48] of the Powerline Bushfire Safety Taskforce, arising from the Royal Commission into the Black Saturday fires in Victoria, all of whose recommendations were adopted by the Victorian State Government.

The assessment concludes that it is foreseeable that safety risks for Endeavour Energy workers and the members of the public will increase from the AER's draft determination where it is proposed that Endeavour Energy's operating and capital expenditure be significantly reduced relative to recent actual expenditure levels. The R2A report states that the analysis indicates:

> *"….if Endeavour Energy were to operate within the constraints of the draft determination, then in the short term, the number of safety incidents, especially to employees, is expected to spike…...In the longer term, this analysis indicates that for the foreseeable threats to members of the public considered in this review, a doubling in fatalities from network hazards would most likely occur. In addition, the likelihood of the Endeavour Energy network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) is increased by around 60%."*[49]

R2A also states that the AER appears to accept that there will be an increase in unexpected events resulting from the draft determination. The report further notes:

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[45] AER Draft Decisions on NSW Electricity Distribution Regulatory Proposals 2015-19

[46] 2009 Victorian Bushfires Royal Commission Final Report, July 2010 (Parliament of Victoria) 4.5.1

[47] Endeavour Energy Asset/System Failure Safety Due Diligence Review January 2014 (R2A)

[48] Powerline Bushfire Safety Taskforce Final Report 30 September 2011 (in particular Appendix E)

[49] R2A Endeavour Energy Asset/System Failure Safety Risk Assessment January 2015, page 4

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"The AER draft determination as it stands, is in effect, directing Endeavour Energy to disregard Endeavour Energy's own determination of what Endeavour Energy believes is necessary to demonstrate SFAIRP under the provisions of the Work Health and Safety Act 2011."[50]

Work Health Safety Act 2011

Primary Duty of Care

Under the WHS Act, the Primary Duty Holder is a 'person conducting a business or undertaking' (PCBU). There are a number of obligations with which a PCBU may need to comply but the primary duty of care is set out at sections 19 (1) and 19 (2) of the WHS Act.

Under this duty, the DNSP must ensure so far as is reasonably practicable:

1. the health and safety of workers (which is defined to include contractors) while they are at work in the business or undertaking; and
2. that the health and safety of other persons (which includes members of the public) is not put at risk from work carried out as part of the conduct of the business or undertaking (maintaining the safety of the Network Asset / System).

The primary duty is limited by what is "reasonably practicable". This is defined under the WHS Act as that which is, or was at a particular time, reasonably able to be done in relation to ensuring health and safety, taking into account and weighing up all relevant matters.

A PCBU needs to consider what is able to be done in relation to the identified risk and then the extent to which those identified control measures are reasonable in the circumstances. However, cost, of itself is unlikely to be a sufficient justification for choosing a lower order safety control measure (or for not implementing a safety control measure) unless the cost is "grossly disproportionate to the risk".

Officer's Duty

Under the WHS Act, an Officer of the PCBU must exercise due diligence to ensure that the PCBU complies with its duty or obligation under the WHS Act. Due diligence is defined to include taking reasonable steps to ensure that the PCBU has available for use, and uses, appropriate resources and processes to eliminate or minimise risks to health and safety from work carried out as part of the business or undertaking.[51]

We are of the opinion that the AER as a public authority is a PCBU under the *Work Health and Safety Act 2011 (Cth) (Cth WHS Act)* and, accordingly, is subject to the primary duty of care. This means that the AER is required to ensure, so far as is reasonably practicable, that the health and safety of other persons is not put at risk from work carried out as part of the conduct of the AER's undertaking, including in making distribution determinations.

Significantly, the recent Royal Commission into the Home Insulation Program (HIP) made a number of recommendations designed to avoid future systemic failures and on the issue of 'risk' concluded:

"Risk cannot be abrogated – Government must recognise that as much as it might seek to do so, risk cannot be abrogated. The responsibility of Government is to care for its citizens and to exercise care and diligence to do everything reasonable to ensure citizens are not placed in danger by its actions, particularly risk of death and serious injury."[52]

[50] R2A Endeavour Energy Asset/System Failure Safety Risk Assessment January 2015, page 30

[51] Work Health and Safety Act 2011(NSW) s 27(5)(c)

[52] Ian Hanger, Report of the Royal Commission into the Home Insulation Program (Commonwealth of Australia, 2014) [1.1.17]

Impact of the AER draft determination on WHS obligations

We are of the opinion that if the AER is aware of the safety impacts of the proposed operating and capital expenditures allowed for in the draft determination and it makes its final determination allowing for these same levels irrespective of these safety impacts, it will be in breach of its primary duty of care under the Cth WHS Act.[53]

Based on our consideration of all factors, we are also of the opinion that the proposed operating and capital expenditure allowed for in the draft determination would preclude Endeavour Energy from complying with its obligations under the WHS Act.

It is also Endeavour Energy's view that the AER's final determination, if it allows for similar operating and capital expenditure levels provided for in the draft determination, would impact Endeavour Energy's officers ability to comply with their personal duties under the WHS Act.[54]

Implications for Insurance Arrangements

Endeavour Energy, Ausgrid and Essential Energy have jointly insured "common risks" for a number of years including bushfire liability. The bushfire risks are insured under a General Liability insurance policy. A key platform for our ability to obtain cost effective insurance for this catastrophic risk is the prudent risk management practices we employ, particularly in relation to vegetation management and the use of LIDAR to identify vegetation encroachment and asset maintenance priorities.

Aon Risk Solutions was engaged to provide advice on potential implications to insurance arrangements arising from a reduction in preventative asset management particularly vegetation management expenditure. A summary of Aon's advice (Attachment 1.10) follows:

> *"If underwriters become exposed to bushfire losses arising from insured contingencies occurring across Australia or internationally, say from increased claims arising from a poor bushfire or wildfire season, then market conditions could rapidly deteriorate.*
>
> *In such circumstances, and given the past positive differentiation that NNSW has effectively conveyed to markets demonstrated through effective and prudent risk management regimes including vegetation management initiatives, faced with a more exposed risk profile the NNSW insurers could seek other opportunities in utilisation of their capacities and simply walk-away.*
>
> *This holds the potential to leave NNSW in an untenable, effectively partially or even largely uninsured position at some point over the course of the next 5 years.*
>
> *Based on the findings, analysis and considerations contained within this Report, Aon estimates that under current insurance market conditions and without further losses from bushfire liability accruing to the specialist insurance market, potentially estimated and unverified composite premium costs …….. representing an increase of up to c.125% over the current 2014-2015 insurance position."*[55]

During the 2014-15 renewal we evidenced withdrawal of a number of global underwriters for Australian bushfire liability insurance. This follows the withdrawal of participating US underwriters in 2012.

If underwriters perceive that there is a lessening of our prudent asset management practices including vegetation management then there is a strong likelihood that we will not be able to obtain effective cover for our bushfire risks potentially exposing NSW DNSPs to a level of uninsured bushfire risk.

We also note that the expenditure required to maintain Endeavour Energy's current electricity network would result in a similar reduction in the opex and maintenance of associated systems and controls that prevent and

[53] Work Health and Safety Act 2011 (Cth) s 19

[54] Ibid s 27

[55] The Insurance Advice Report, 13 January 2015 (Aon Risk Solutions), pages 5-6

mitigate environmental impacts. These controls include programs such as contaminated site assessment and oil containment, installation and maintenance.

1.3.2 Reliability issues

Supply Reliability

Our substantive regulatory proposals focused on meeting the long term objectives of our customers in terms of safety, reliability and affordability. The reliability aspects of these objectives are determined relative to our past reliability performance, the results of our customer engagement regarding customers' reliability expectations and our specific obligations under Schedules 2 & 3 of the NSW Design and Reliability Performance Licence Conditions, 2014.

The previous section on safety implications has discussed our approach to safety and our considered approach to preparation of our capital and operating programs with the required outcomes in mind. A very similar approach has been adopted in terms of meeting reliability objectives, with many planned activities inherently fulfilling both safety and reliability objectives concurrently. One fact which the AER has not commented upon in their draft determination is that the majority of network events which result in a reliability impact also provide the opportunity for a safety incident if not adequately prevented or contained. Therefore, removing the possibility of a failure addresses both safety and reliability.

Similarly to safety, the business has used widely recognised risk based methodologies and processes, including Failure Mode Effect & Criticality Analysis/Reliably Centred Maintenance (FMECA/RCM) to develop the programs which underpin the expenditure forecast put forward to the AER in our draft determination. These processes indicate that the expenditure forecasts put forward in our initial proposal, now updated in our revised proposal, are required to manage our network with the required levels of safety & reliability.

In parallel with the safety implications identified above, a failure to allow us to recover the cost of the programs put forward in our proposal will lead to poor reliability due to increased risk of asset failure, longer response times during emergencies such as major storms or fires and potential failure to meet our NSW licence obligations for reliability.

Implications of AER Draft Decision

As noted elsewhere in our revised proposal, in their draft determination the AER has formed a view, based primarily on high level benchmarking and/or modelling, that the NSW electricity distributor's forecasts did not meet the objectives of the NER. As a result the AER has rejected those forecasts and proposed the substitution of significantly lower alternative forecasts, with reductions on the order of 20-40% to both capex and opex. We do not believe that, in developing these alternative forecasts, the AER had due regard to the reliability (and safety) risk impacts. If we were to only spend within the limits indicated by the AER's draft determination a significant worsening of reliability outcomes would result.

In considering the implications of the AER's draft determination we sought the advice of Jacobs Group Australia in two areas – engineering prudency and reliability impacts. (Attachments 1.13 and 1.14)

In terms of consideration of overall risks resulting from the AER's draft determinations Jacobs noted:

> *"In our opinion, the AER does not appear to have apposite consideration of the impact that the revised expenditure levels have on the risk exposure of the NSW DNSPs."*[56]

With regard to reliability impacts Jacobs commented that:

[56] Jacobs, Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment, January 2015, p2

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"it is likely that the current levels of reliability cannot be maintained in the longer term with the restricted capital works program likely to result from the proposed capex reductions"[57]

and

"The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a ten year period" [58]

The reductions proposed by the AER, if implemented, would have impacts on the following areas:

- **Inspections & Maintenance** – Reduced capacity for inspections and maintenance, leading to extensions of maintenance inspection cycles away from optimal FMECA/RCM identified maintenance intervals, therefore resulting in higher failure rates. In their System Capex and Maintenance Prudency report, Jacobs observed that:

  "The FMECA/RCM method analyses a variety of factors to provide a transparent view of the risks associated with different scenarios. As a result, informed decisions can be made as to the optimised inspection and maintenance regimes, considering cost, safety and reliability. In quantifying risk the tool analyses a breadth of direct and indirect costs in conjunction with probabilities and consequence costs. In Jacobs view significant reductions to system opex would disrupt the optimised programmes, which, while potentially reducing opex in the short term, would lead to higher overall costs over the medium to longer term. This would not be a prudent outcome for the NSW DNSPs." [59]

- **Emergency Response** – Reduced capacity to respond to network faults would result from staff reductions necessary to meet expenditure forecasts set out in the draft determination. This would lead to longer fault response & restoration times, particularly during severe weather, or fires when there are high numbers of customers affect by faults ("high SAIDI days").
- **Capital Programs** – Our overall capital program is designed to support the continued safe and reliable performance of our network as assets decline in performance towards the end of their life and as peak demand on the network grows over time. Cuts such as those proposed by the AER compromise our ability to replace those assets with deteriorated performance and to support growth in maximum demand, resulting in a progressive worsening of reliability outcomes over time.
- **Compliance Capex** – There is a small component of capex in our program, targeted at specifically addressing those parts of the network which fail to comply with Schedule 3 of the NSW Design & Reliability Performance Licence Conditions, setting out individual feeder performance requirements. The AER disallowed this expenditure in their draft determination.

Reliability Impact Assessment

Jacobs examined the above factors, including modelling of the impacts of maintenance reductions and the longer response times resulting from the AER draft determination if it was implemented.

Jacobs modelled the impact on SAIDI of longer maintenance intervals and therefore higher failure rates based on FMECA/RCM analysis undertaken across the three NNSW businesses. They then modelled the further impact on SAIDI (& CAIDI) of longer response time due to projected reductions in staff numbers as a result of the AER draft determination. Impacts on response times were confined to the approximately 10% of days when the number of outages on the network was large enough that resources to respond to faults would be constrained. On the remaining 90% of days it was assumed that staffing reductions had no impact on response times. Resource availability for both routine inspections/maintenance and emergency response was determined by applying the AER's reductions consistently across all opex.

In their report Jacobs noted that, in relation to reliability:

[57] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p10

[58] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p3

[59] Jacobs, Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment, January 2015, p 47.

> *"The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a ten year period"* [60]

As there were more potential sources of unreliability which were discussed but not quantified (including repex impacts), given the timeframe available, Jacobs also noted that

> *"For the various reasons discussed, it is believed that this analysis of the impact of the Draft Decision underestimates the negative impact (increased frequency) of the impact of outages on the network."*[61]

Jacobs found that Endeavour Energy's SAIFI would increase by 1.3% between the base year of 2014-15 and 2020, with SAIDI worsening by 11.6% over the same period.[62] They also found that by 2025 SAIFI would worsen by 2.7% and SAIDI by 13.1%.

While Jacobs did not model the overall cuts to system capex, they did discuss the drivers for capital investment. They discussed the fact that not committing repex early enough can result in asset failure with consequences including loss of supply, injury or damage. They noted that, if not committed in time augex can also result in negative reliability consequences. Overall Jacob's view was that:

> *"it is likely that the current levels of reliability cannot be maintained in the longer term with the restricted capital works program likely to result from the proposed capex reductions."*[63]

Impact on Licence Compliance & STPIS

In our initial proposal we proposed reliability capex to ensure compliance with reliability performance targets set out in jurisdictional licence conditions, in particular for the worst performing parts of our network.

In its draft decision the AER has rejected the entire reliability program, expressing a view that our proposal did not clearly indicate the basis for, and amount of, expenditure for compliance, that it appeared the proposed amount included capex to avoid penalties under STPIS and that it was unclear whether the expenditure had been included in the AER's analysis of other capex categories.

Matters of allocation are addressed and clarified in the body of our revised proposal. With those matters addressed, reliability compliance capex ought to be allowed by the AER so as to meet jurisdictional obligations, a clear objective of the NER.

The AER's draft determination outcome, if implemented, would not allow Endeavour Energy to maintain reliability at current levels as we cannot fund investment through avoided STPIS costs. We agree that the STPIS should fund overall reliability improvements which are separate to regulatory obligations. However, our proposal sought to maintain compliance with regulatory obligations and should be allowed.

On this matter Jacobs noted:

> *"Specific cuts to reliability capex will prejudice NNSW's ability to meet Schedule 2, 3 and 5 of licence conditions even if not making a large impact on STPIS. Reduction of programmes targeting poorly performing feeders will have a direct negative impact on supply reliability. However, due to the small proportion of these programs within the overall capital program and also due to the focus of these programs on individual poorly performing feeders, rather than overall system reliability, the STPIS will not generate savings or penalties equivalent to the cost of the works. Therefore, these programs must be funded in addition to any STPIS benefits/penalty."*[64]

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[60] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p3

[61] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, page 14

[62] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, page 4

[63] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, page 10

[64] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, page 9

We have responded to the Service Target performance Incentive Scheme in Chapter 3 of our proposal. However, we note that using the analysis referred to above, Jacobs' further modelling of STPIS impacts indicated that assymetrical STPIS penalties from 0.56%%, rising to 0.67%[65] over the regulatory determination period, would result from the AER's draft determination if implemented. It must be noted that the reliability impacts and therefore STPIS penalty estimates are conservative and should not be taken as an alternative STPIS proposal. They serve only to provide confirmation that the implications of the AER's draft determination are material.

Given this assymetric outcome, a STPIS would be inappropriate if the AER's draft determination was to be implemented. We would only support a STPIS if our revised capital and operating programs were accepted in the AER's final determination.

1.3.3 Financial sustainability

The AER's draft decision made significant reductions to Endeavour Energy's proposed revenue allowances over the 2014-19 regulatory period. This was the result of severe cuts to proposed levels of capex, opex, and the allowed rate of return.

The AER's draft decision implicitly assumed that it will be possible to maintain a safe, secure and reliable network with the revenue allowance set out in its draft decision. As demonstrated in this revised proposal, the safety, security and reliability of Endeavour Energy's network will only be maintained with the level of opex and capex set out in this revised proposal.

If the AER's draft decision on Endeavour Energy's allowed revenues over 2014-19 was applied in a final determination, Endeavour Energy would still need to spend capex and opex in line with this revised proposal to avoid exposing the network to an unacceptable level of safety, security and reliability risks. The safety and reliability consequences of not investing at the levels set out in this revised proposal are addressed in the Chapters 1, 5, and 6. In addition, Endeavour Energy would still be required to meet wages costs, contractual obligations (such as vegetation management, IT and fleet costs) and interest costs on its accumulated debt portfolio (which has been managed on a benchmark efficient staggered portfolio basis).

Therefore, if applied in a final determination, the AER's draft decision on allowed revenues would not enable Endeavour Energy to recover revenues sufficient to cover its benchmark efficient costs, thus causing a material deterioration to Endeavour Energy's financial sustainability. Providing insufficient revenues to recover Endeavour Energy's efficient costs does not meet the requirements of the revenue and pricing principles in the NEL, the NEO or the Rules.

We have received advice from Professor David Newbery, an internationally recognised expert on economic regulation and reform of network industries and the transport sector, which suggests that regulatory best practice is to have regard to the impact on a DNSP's credit rating as a result of changes to opex allowances. In regards to the appropriate revenue and expenditure allowance for opex, Professor Newbery noted in his report provided as Attachment 1.06:

> *"I consider it unlikely that such a large reduction, in such a short space of time, to the NSW DNSPs' allowances would not impact on their ability to maintain a reliable and safe network without negatively impacting on their ongoing financeability and viability of the companies as economic entities. If the P0 reduction prejudices cash flow, then commercial credit rating agencies would likely downgrade the credit status of the companies, which would raise their WACC and possibly have a greater impact in raising total costs than the possible incentive effect might have on opex…."*

[65] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, page 22

1 ABOUT THIS REVISED PROPOSAL

> *"….International precedent indicates that when regulators have identified large inefficiencies they have used regulatory judgment to ensure that a feasible and sustainable price path is set that does not prejudice the companies' credit standings and WACC".*[66]

Professor Newbery also noted:

> *"It is often the case that regulators are required to take into account both the interests of consumers and the ongoing financeability of an efficient regulated company. If a regulator were to set either an unrealistic or unachievable efficiency target for regulated companies then both of these aims may be put at risk."*
>
> ***"If there is a material error in the application of the building blocks then at the extreme a regulated company would face difficulties in raising finance to continue its operations.***
>
> ***Therefore, the quality, reliability, safety and security of the electricity distribution system would be called into questions as the service providers would need to prioritise or reduce its services."*** *[emphasis added]*[67]

Endeavour Energy has engaged Standard and Poor's (S&P) to assess the financial impact of the AER's draft determination by examining the revenues contained in the AER's draft determination combined with the capital, operating and interest costs as set out in this revised proposal. The confidential S&P report, provided as Attachment 1.15 outlines that Endeavour Energy's credit rating under these criteria would fall well short of the AER's benchmark credit rating of BBB+, and would result in a credit downgrade to sub investment grade.

As discussed in confidential Attachment 1.16 from UBS, Endeavour Energy would face difficulties when trying to raise debt finance with a credit rating that is sub investment grade. The pricing of sub investment grade bonds in the Australian market results in sub-investment grade companies facing a significantly higher cost of debt than BBB, or BBB+ rated firms. UBS's analysis also suggests that there is very limited liquidity for such bonds in the Australian market. These factors would mean that a credit rating downgrade would significantly impair Endeavour Energy's financial sustainability.

UBS suggests that Endeavour Energy would not be able to fund their debt requirements nor fix their cost of debt on a benchmark efficient basis unless rated BBB+ or higher. A rating less than BBB+ would result in higher cost of debt, restrictive covenants, less liquidity and higher hedging costs.

Assuming no change in financial forecasts (revenue at the level set by the AER in its draft decision, opex or capex set at the level forecast by Endeavour Energy in its revised proposal). Endeavour Energy will require a significant reduction in debt in order to remain financially viable over the forecast period. A change in the capital structure from 60% debt and 40% equity to a structure with lower debt would see Endeavour Energy deviate materially from the credit metrics of a benchmark efficient entity as defined by the AER. Currently Endeavour Energy enjoys an investment grade stand alone credit rating and its debt/equity structure is aligned to the AER's efficient benchmarked capital structure. The draft decision in one action moves Endeavour Energy significantly away from the benchmark efficient capital structure and directly results in the most significant downgrade ever faced by the organisation moving it from investment grade credit rating.

To move to a significantly lower debt structure would require a material equity injection, which would not be a viable proposition for investors who would be asked to commit new funds to an operation generating low or negative equity returns. A significant equity injection would be required to replace most of the existing debt, and equity naturally carries a higher risk than debt so procuring equity for an organisation where equity has little or no prospect of a return on investment for some years would be extremely challenging. The likely operational outcome for the business as Professor Newbery sets out above would be severe, with debt and equity capital providers requiring significant cutbacks to operating and capital programs in order to generate positive returns at some point in the future. This would in turn compromise the safety, security and reliability of the network service.

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[66] David Newbery, Expert evidence January 2015, page 17

[67] David Newbery, Expert evidence January 2015, page 27

These outcomes are severe, but highly likely if the AER draft determination becomes a final determination and are certainly not in the interest of consumers as required by the NEO. The interests of consumers are served where regulatory decisions preserve the incentives for debt and equity capital providers to continue to invest in and support network service providers to provide a reliable, secure and safe service to consumers. In its draft determination the AER directly provides disincentives to debt and equity investors in network service businesses to provide safe, secure and reliable services to consumers.

Clearly, the credit assessment outcome arising from the AER's draft determination is unsustainable and would have a serious and adverse impact on Endeavour Energy's financial sustainability. Endeavour Energy's revised proposal would provide sufficient revenues to facilitate a financially sustainable business, while the AER's draft determination would not.

2 OUR CUSTOMERS

Summary

Our initial proposal reflected our genuine commitment to incorporate customer and stakeholder priorities identified through strategic engagement initiatives. We challenge the AER's view that our initial proposal failed to reflect consumers' long-term interests and reject its alternate views on a preferable decision under the NEO.

Around 2.2 million people across Sydney's Greater West, the Blue Mountains, the Southern Highlands, the Illawarra and South Coast depend on Endeavour Energy to deliver a safe and reliable electricity supply every day. The majority of our customers are residents and small businesses. Importantly, we have 17,687 life support customers who depend on us to provide reliable electricity to power essential medical equipment.

Our stakeholders include State government bodies and representatives, local councils, emergency service providers, chambers of commerce, electricity retailers, accredited service providers, industry associations, suppliers, media outlets, industry commentators, consumer advocacy groups and educational institutions.

We identified our consumer and stakeholder cohorts in our engagement strategy. We also worked with Networks NSW to identify and prioritise shared stakeholders in an industry wide workshop, held in December 2012. We also assisted to plan and implement Networks NSW Customer and Stakeholder Strategy. This was designed to streamline engagement initiatives so as to avoid consultation fatigue, highlighted in the AER's Better Regulation meetings. The Networks NSW engagement strategy was endorsed by the Executive Leadership Group.

Endeavour Energy's approach included a broad range of engagement activity and results that were detailed in our initial proposal. The results were made publicly available on our website. We welcome comments from the AER, Consumer Challenge Panel (CCP) and other stakeholders that acknowledge the contribution of this work and suggestions on where it can be genuinely improved.

We endorse comments from the AER in its draft determination and the CCP in its submission to our initial proposal that also acknowledged the challenges we faced in adopting the AER's Consumer Engagement Guidelines as part of our regulatory proposal, given that the guidelines were not published until November 2013, two months and five months before these proposals were submitted to the AER.

In summary, in its draft determination the AER noted our efforts to improve engagement with consumers but it went on to:

- Reject our consumer engagement findings based on the breadth and number of submissions made in response to our initial proposal
- Use these points as a factor in the AER's assessment of our overall revenue requirement
- Cite alternative customer priorities and concerns – without any solid evidence to support this, beyond anecdotal evidence and unsubstantiated consumer feedback.

We have reviewed the AER's feedback to understand whether the issues raised by the AER impact on our revised proposal. We acknowledge that while engagement is an ongoing process of learning and improvement, we nevertheless consider the issues raised by the AER are not material.

We also reject the AER's conclusion that the outcomes of our proposal do not reflect consumer concerns or views. In particular, we are deeply concerned that the AER seems to have dismissed our findings, without providing any solid evidence to support its alternative conclusions.

2 OUR CUSTOMERS

Endeavour Energy maintains that the results our broad engagement initiatives do reflect consumers' priorities and concerns as stated in our regulatory proposal; that is:

- ensuring safety is not compromised;
- maintaining the reliability of the network; and
- addressing issues of affordability by keeping further network price increases to below the cost of living.

In this chapter, we also highlight concerns with the manner in which the AER's assessment of customer engagement has been used to inform its overall determination. We believe the AER's consideration of customer engagement should have been limited to its assessment of capex and opex, rather than form part of its justification on why its overall decision is preferable under the NEO. We believe the AER has not properly considered the evidence that shows customers expect Endeavour Energy to maintain the existing reliability and safety levels which underpin our expenditure plans.

In this respect, further engagement with our customers and broader stakeholders since submitting our initial proposal adds weight to the views expressed in our initial proposal: that the majority of our customers value the safety and reliability of the network and do not wish to see this compromised, even if it might mean reduced network charges.

We also provide the AER in this proposal with information on our long-term plan to engage with customers in the future. The key outcomes of this engagement will continue to be used to ensure consumer priorities drive our business decisions.

2.1. Role of customer engagement under the Rules

A key element of the 2012 AEMC Rule change was to involve customers more in the regulatory framework. The Rules required that our initial proposal include a plain English overview for customers and a description of how we have engaged with electricity consumers and sought to address any relative concerns identified as a result of that engagement.

The Rules also provided a mechanism for the AER to consider customer engagement as part of its decision making for opex and capex. Assessing the extent to which the proposed expenditure addresses customers' concerns (as identified through customer engagement) is one of 11 different factors that the AER must have regard to in deciding whether to accept the proposed forecast capex and opex.

The AER released a Consumer Engagement Guideline in November 2013. Its purpose is to set out a framework for electricity and gas service providers to better engage with consumers and to set out the AER's expectations of customer engagement. Specifically, the AER notes that:

> *"… the quality of a service provider's consumer engagement will be a factor in how we assess expenditure proposals. We will consider whether and how well a service provider considered and responded to consumer views, equipped consumers to participate in consultation, made issues tangible to consumers, and obtained a cross-section of consumer views. We will make our assessment on a case by case basis, considering whether it would have been reasonable to engage on a particular issue."* [68]

On this point, we note the following statement of the AEMC in considering changes to the NER:

[68] AER, Consumer Engagement Guidelines, November 2012, p22.

> *"While the final position Rules in some areas, such as the expenditure forecasting assessment guidelines require engagement to occur in a certain way, the Rules should provide for the outcomes of engagement, not the engagement itself."* [69]

We also note that the AER's Consumer Engagement Guidelines emphasises the importance for network businesses to commit to genuine and ongoing consumer engagement:

> *"We expect service providers to recognise, understand and involve consumers on an ongoing basis, not just at the time an expenditure proposal is being prepared."*[70]

The guidelines also state that:

> *"Together, the principles and components seek to drive consumer engagement and a commitment to continuously improve that engagement across all business operations."*[71]

We endorse the intent of these statements as well as the AER's clear acknowledgement that meaningful consumer engagement is built up over a longer period:

> *"…service providers will need some time to develop and implement robust and comprehensive engagement strategies and approaches."*[72]

Consistent with the intent of this approach, Endeavour Energy developed a strategic and long term approach to its engagement with customers and stakeholders, previously outlined in our initial proposal. Our customer engagement plan for 2014-19 is further explained in this chapter and is at Attachment 2.01 (draft customer engagement plan).

This included our commitment to embed engagement practices into our business processes, continue to engage with consumers beyond our regulatory proposal and to review and renew our engagement strategies and activities.

We find it contradictory for the AER to clearly lay down these expectations and acknowledgements, yet seek to ignore them when judging our consumer and customer engagement activity. This is particularly unreasonable given the late publication of its Consumer Engagement Guidelines.

We believe this a fundamental breach of AEMC's wishes for all parties to engage in "good faith" (AEMC page 360) during this regulatory process.

[69] AEMC, Regulation of Distribution Services, Final report, November 2012, p36.

[70] AER, Consumer Engagement Guidelines, November 2012, p8

[71] AER, Consumer Engagement Guidelines, November 2012, p5

[72] AER, Consumer Engagement Guidelines, November 2012, p12

2.2. Customer engagement activities identified in initial proposal

In preparing our initial proposal, we sought to respond to customers concerns about affordability by developing expenditure plans that incorporated significant efficiency programs. In this way we were able to restrict increases in network charges to no more than CPI.

Our engagement approach was based on best practice community engagement principles set out by the International Association of Public Participation. We have used these principles since 2008 and they have been used once again to conduct engagement for our regulatory submission.

Whilst preparing the regulatory proposal, the AER's consumer engagement guideline was released in November 2013. Despite the limited time available, we conducted additional engagement activities with our customers to ensure alignment with the guideline.

The research we conducted post the release of the guideline reinforced the overarching objectives we had set in our regulatory proposal, as the objectives were based on our understanding of customer and stakeholder sentiment. Specifically these key objectives continue to be:

- **Stable prices** – We propose to keep average price increases to our share of customers' electricity bills to at or below CPI for the next five years.
- **Reliability** – We propose to maintain reliability.
- **Safety** – Our capital and operating plans aim to deliver programs that are safe and sustainable for the electricity network and the communities it serves.

In Chapter 2 of our initial proposal we presented a table which clearly outlined the key priorities of customers which we attained over months of engagement activities. The specific feedback (listed above) was accurately and transparently used to drive our regulatory plans. As outlined in our initial proposal, we obtained this feedback through the following activities:

- Conducting quantitative and qualitative research with assistance from external customer engagement specialists Woolcott Research. This involved surveying more than 900 residential and 300 small to medium business customers via telephone surveys and focus groups.
- Extending the reach of our engagement program through an innovative Facebook campaign, designed in conjunction with Ausgrid and Essential Energy, and featuring online polls and infographics. Six months of website interaction was collated.
- Analysing two years of existing customer research including our complaints and compliments data, our quarterly customer satisfaction reports, our energy efficiency product trials, media and Energy & Water Ombudsman NSW reports.
- Holding two consumer engagement forums in Penrith and Wollongong on priority customer issues, with assistance from external customer engagement specialists KJA. These were attended by 99 residential and small business consumers.
- Meeting with a group of peak consumer representatives at a joint Networks NSW forum to identify issues of concern and begin a discussion on the need to reform electricity tariffs. Networks NSW CEO Vince Graham and Endeavour Energy's General Manager for Network Development Ty Christopher played a central role in delivering these forums and attaining customer feedback.
- Presenting plans to contain our share of total public lighting costs to no more than CPI for the next five years to representatives of the three Regional Organisations of Councils, regular meetings with 18 local councils in our network and the other five councils as required. This was in addition to our regular six monthly visits to monitor their satisfaction with our public lighting service.
- Writing to retailers, industry associations, chambers of commerce, local government, Members of Parliament and other community stakeholders seeking feedback on our electricity plans and prices.

- Promoting our plans to contain our share of bill increases through metropolitan and regional media and inviting feedback from customers and stakeholders.
- Informing Endeavour Energy's Customer Consultative Committee about the key themes and priorities emerging from our engagement sessions, seeking their feedback on our plans and their priorities.
- Meeting with the AER's Consumer Challenge Panel to respond to questions about our proposed plans.
- Liaising with retailers on our five year plans and proposals for tariff reform via a Networks NSW forum.
- Developing an easy-to-read summary of our full regulatory proposal, outlining the benefits and risks for consumers which has been posted on our website and distributed throughout the network.
- Sharing our plans and presentations via our website in the interests of broader transparency.

In Chapter 2 of our initial proposal, we also demonstrated how we met best practice principles for engaging with customers, and showed how we had met the AER's consumer engagement guidelines. We also provided the AER with 11 detailed attachments relating to our customer engagement activities.

2.3. AER's assessment of Endeavour Energy's customer engagement

As we noted in section 2.1, the AER assesses our customer engagement as part of the capex and opex factors when making its decision on whether to reject or accept our proposed capex and opex under the criteria. Accordingly, we have reviewed the issues raised by the AER in the context of revisions to our proposal. Overall, we consider that the AER has not raised significant issues with our engagement processes nor provided new evidence to prompt a revision to any element of our initial proposal.

In terms of the process of engagement, the AER recognised the steps we have taken to implement a consumer engagement strategy. In particular, the AER noted that Endeavour Energy made an attempt to engage with, and seek feedback from, various customer cohorts. While acknowledging our efforts to improve engagement with consumers, the AER considered that we had significant work to do to give consumers more say in the services we provide. In making its finding, the AER commented on issues with our approach to customer engagement which we have addressed in section 2.3.1 below.

The AER also raised concerns with the manner in which we incorporated customers' views, including aligning customers' views to our proposal and identifying risks and benefits of our proposal. We address the AER's concerns in section 2.3.2.

It is not entirely clear to Endeavour Energy how the AER has utilised its findings from customer engagement when making its decisions on capex and opex. The AER's decision on forecast opex suggests that it may have taken into account customer feedback in our proposal on network charges as a reason for rejecting our proposed opex. The AER however did expressly consider customer preferences in its analysis of whether its overall decision is more preferable under the NEO. It noted the breadth of submissions did not support our proposal as being in the long term interests of customers, in particular that submissions suggest a need for substantial revenue reductions. In section 2.3.3, we discuss how the AER has used its findings on customer engagement to inform its constituent decisions, and overall draft determination.

2.3.1 AER concerns with our approach to customer engagement

While broadly supportive of the engagement activities we had undertaken, the AER raised issues with aspects of our approach to engaging with customers.

- Based on submissions, it identified three areas where it believed stakeholders had not been equipped to participate or where issues had not been made tangible to consumers. These included public lighting, metering and rate of return.

- The AER noted that the CCP and other stakeholders submitted that we could do more to make issues tangible to consumers. In particular, it stated that we should provide consumers with sufficient and relevant information as part of our customer engagement activities.
- It noted that the Ethnic Communities Council of NSW outlined possible areas where we could better target our engagement to reach customers from culturally and linguistically diverse backgrounds.

We recognise that there is more we can do to improve our customer engagement activities over time and have plans to independently evaluate our existing approach. We have also addressed each of the AER's concerns below.

Public lighting

The AER noted that the main barrier to consumers being able to participate in the consultation process was the confidentiality claims made by Endeavour Energy over public lighting information. The AER also noted Endeavour Energy seemed to have been reluctant to support the AER's efforts to have more information about public lighting available in the public domain, despite similar information being available in other jurisdictions around Australia.

By way of background, senior leaders from Endeavour Energy meet with 18 of the 23 councils mainly located within our franchise area twice a year to understand each councils' concerns and satisfaction with our public lighting services. We have agreed to meet with the other five councils on a case-by-case basis. We published our report of engagement with councils on public lighting matters with our initial proposal and note that the large majority of councils were satisfied with our engagement approach and our relationship with them.

Of the 23 councils mainly located within our franchise area, only two - Holroyd and Camden councils - commented on confidentiality claims made by Endeavour Energy. In response we note that Endeavour Energy had sought the AER's assistance in not publishing commercially sensitive information as doing so breached commercial arrangements with suppliers of public lighting components such as lamps and lumenaires, and compromised our ability to competitively procure these items.

As local councils also procure public lighting components for their own purposes, release of this sensitive information would have also adversely impacted the position of Endeavour Energy's suppliers in their commercial dealings with councils.

To address this issue, Endeavour Energy is working with the AER to release this information under strict confidentiality provisions to the consultants representing local councils in a manner that preserves the commercial position of all parties, including suppliers.

On this basis, we do not believe that the AER's assessment that we failed to equip customers to participate in consultation and made issues tangible to consumers is entirely proven.

Metering

The AER noted that it published a discussion paper on metering in December 2012 and confirmed its position in its Stage 1 F&A published in March 2013. During that time, the AER had suggested Endeavour Energy should consult with its customers on the range of options that might be available.

The AER suggested there was little evidence that Endeavour Energy consulted customers on options for how meters could be priced in the future, noting that Networks NSW did conduct a workshop with retailers in May 2014 to provide advanced notice of the metering charges in its proposal, but its understanding is that Endeavour Energy did not otherwise consult on its proposed charges. The AER noted that the absence of this consultation was reflected in submissions from Origin and PIAC which indicated that Endeavour Energy had developed its metering proposal independent from consumers.

In response we note that this is the first year of a new framework introduced by the AER to encourage greater competition in metering.

Given this, we committed to further consultation with retailers on specific issues regarding metering once our initial proposal had been submitted (see Retailer's Forum Engagement Report May 2014) and our position in response to the new framework had been outlined as the basis for further consultation with stakeholders. Attachment 2.02 contains all our engagement activities with customers and stakeholder since May 2014.

We have noted the feedback from retailers and PIAC on our proposal as part of this consultative process, particularly in relation to exit fees, and on this basis, acknowledge the needs for further consultation with them and the AER on exit fees that do not create sovereign risks or introduce cross subsidies between customers.

Rate of Return

The AER noted that there was broad stakeholder disappointment that Endeavour Energy departed from its rate of return guideline with little or no consultation with consumers and without demonstrating that these variations were made in the long-term interests of consumers or represent the efficient costs of an efficient benchmark firm.

In response we note that it is not correct to state that Endeavour Energy departed from the rate of return guideline with little or no consultation with consumers, and without demonstrating that these variations are made in the long-term interests of consumers or represent the efficient costs of an efficient benchmark firm. In response we note that, while the rate of return guideline is important in setting out the methodologies the AER proposes to use in estimating the allowed rate of return for determinations, the guideline is not binding on a DNSP in developing its regulatory proposal or the AER in making a determination.

Throughout the rate of return guideline consultation process, Endeavour Energy has consistently and publicly advocated a return on capital that minimises volatility on network charges over time. As the guideline recommends, we have also clearly outlined this in our initial proposal and the reasons for our approach including:

- Endeavour Energy has prudently managed refinancing risks over the past ten years by issuing debt on a staggered portfolio basis and therefore does not face the transitional issues that may be a factor with other network service providers;
- We would be exposed to significant risk arising from differences in market conditions under which our debt was actually raised and the market conditions under which the AER transition allowance assumes debt was raised;
- Adopting the AER's guideline would effectively encourage Endeavour Energy to move away from an approach to financing determined as efficient by the AER to an approach the AER considers is inefficient (the use of swaps and hedges) to manage the interest rate risk introduced by the guideline's short term transition.

The detailed reasons are further elaborated in the CEG report titled "Debt transition consistent with the NER and NEL" which has been available to the AER and other stakeholders since 30 May 2014 when our initial proposal was submitted.

Making issues more tangible to customers

The AER noted that the CCP and other stakeholders submitted that Endeavour Energy could do more to make issues tangible to consumers. For example, Origin stated that to promote constructive and informed contributions from stakeholders it is imperative that the data and information that underpin a regulatory review process be presented to stakeholders in a manner that is, to every extent practicable, transparent and comparable across each of the regulatory reporting documents and over time.

Along similar lines, the CCP submitted that the NSW distribution network businesses are not providing consumers with sufficient and relevant information as part of their consumer engagement activities. To make issues more tangible to consumers, the AER expected that Endeavour Energy will make more effort to provide various consumer groups with the information they need to participate.

In response we note one of the barriers to effective engagement is a general lack of understanding of the highly detailed regulatory nature of the industry and the structure of pricing and charges, which requires significant preliminary education. Consumers themselves suggested more needs to be done by Endeavour Energy to raised awareness of what we do. We recognise we have more work to do in this regard.

Despite this, we invested considerable effort in developing simple and accessible communication materials during engagement initiatives which we believe have involved meaningful data regarding the costs of building and operating of the network.

We have conducted three consumer engagement workshops this year attended by randomly selected residential and small to medium business customers. These people have been presented with our regulatory plans and we have educated and informed them about the about components of our regulatory proposal. The main purpose of this has been to seek their views on how that our plans align with their priorities.

One further example was demonstrated through our choice modelling research. We provided 1000 randomly selected customers with a series of choices with regards network prices and services. Price was pitched against the number of blackouts which may occur; the timeliness of emergency response; our ability to prune trees to maintain safety standards and the likely impact on their streetscape; the number of power poles that may rot and fall over; and the time taken to repair defective streetlights. Consumers were then asked to select their most preferred option from these different choices. This is set out in full in the choice modelling research report prepared by Ipsos and provided at Attachment 2.03.

The results of this research validate findings from Endeavour Energy's previous engagement initiatives, which showed that while customers are concerned about affordability, the majority are not necessarily willing to trade reliability, safety and service for lower charges.

The new choice modelling research showed:

- while price is a driver of participants' selection of potential service offerings, the majority of customers are not prepared to sacrifice reliability and safety for lower charges.
- changes in service offerings – particularly in terms of the time associated with service restoration and number and length of unplanned blackouts – are also key drivers of choice for Endeavour Energy customers. Specifically, increases in the time taken to restore power to houses and the number and length of unplanned blackouts had significant negative effects on the consideration of potential service offerings.
- customers were much less likely to select scenarios that had longer service restoration times and more unplanned blackouts than the status quo.
- in contrast, vegetation management had the most modest effect on participants' likelihood to consider potential service offerings, indicating that this was the service characteristic that mattered least to consumers.
- the number and length of unplanned blackouts, and service restoration times were also key drivers. With increases in the number and length of these blackouts and the time taken to restore power, participants were less likely to select potential service offerings.
- acceptability of potential service offerings hinged on price, number and length of blackouts and service restoration times. This was demonstrated by the high unacceptability rating of scenario five (which had the lowest quarterly price at $123, but a reduction in the quality of all other service characteristics from the status quo). This option was the second least acceptable offering to customers.
- of significance, scenario five was based on the quarterly network charge that would flow from the AER's draft decision, along with relative reductions in service standards due to reduced revenue, while option 1 (ie the current network quarterly charge coupled with current service levels) rated the second highest in terms of acceptability.

These research findings are supported with research conducted by Ofgem and cited by Dr Gill Owen:

> *"research undertaken by Ofgem suggested that consumers did not want any deterioration in security and availability of supply but they were not willing to pay for significant improvements. CC Group confirmed this was likely to be a reasonable assessment of consumers' preferences…."*
>
> *"…clearly, most consumers would prefer to pay as little as possible for their energy needs, but when it comes to what should be done or not be done as a means of keeping bills down, there will be many different options."*[73]

For this reason, Endeavour Energy plans to 'sense check' the results of this research, and previous willing to pay research with key consumer groups and in its day to day customer engagement.

Broadening activities to culturally and linguistic diverse background

The AER noted that the Ethnic Communities' Council of NSW outlined possible areas where Endeavour Energy could better target its engagement to reach consumers from culturally and linguistically diverse backgrounds who often have limited internet access or English skills to respond to complex questions.

In response we note that in November 2014 we met with the Ethnic Communities' Council of NSW to discuss its draft of "Engaging Culturally and Linguistically Diverse (CALD) Energy Consumers – What Works?" and explore options to engage, and better understand the needs of CALD communities. The minutes from this meeting note that the representative from the Council said she had been working hard to engage organisations within the industry, and that her meeting with Networks NSW had been the first meaningful engagement she had experienced.

Once the draft of the CALD document is complete we plan to publish a supporting document for managers to use when engaging with consumers from CALD communities.

2.3.2 Reflecting and aligning customers views in our proposal

The AER also raised concerns with the manner in which we reflected customer's views in our proposal. We address the AER's concerns below.

Aligning and incorporating customer views

As outlined in section 2.2, we have conducted an extensive program of consumer engagement to attain customer views and priorities with regards price and network services. This research has shown that that our customers' top three priorities are: affordability; reliability; and safety. Endeavour Energy is confident our plans are aligned with consumers long term interests to deliver a safe, affordable and sustainable electricity service well into the future.

Customers have also requested further information on: demand management; improving efficiency; and how to implement more efficient metering technology. Our programs continue to address these concerns through our day-to-day operations and ongoing customer engagement.

We note that there is a direct obligation on Endeavour Energy and the AER (as a public authority) to abide by both the Workplace Health and Safety Law and NEL and we are strongly committed to ensuring we provide and maintain a safe network.

Following the release of the AER's draft determination, Commissioner Greg Mullins, Fire & Rescue NSW, sent a letter dated 4 December 2014 to Vince Graham and Paula Conboy (refer Attachment 1.11) which stated:

> *"I fear that the impact of the draft determination could be a greater reliance on Fire & Rescue NSW in storm situations, due to smaller numbers of available utility staff and less vegetation*

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[73] The potential role of the Consumer Challenge in energy network regulation in Australia: a think piece for the AER 13 March 2013

management activities. As illustrated above, I am deeply concerned that this could lead directly to greater loss of life and property in the community due to fire crews being engaged for even longer periods at "wires down" incidents." [74]

Similarly, a letter from Commissioner Shane Fitzsimmons, NSW Rural Fire Service dated 5 December 2014 to Vince Graham and Paula Conboy (refer Attachment 1.12) stated: [75]

"It would appear that the broader ramifications of the draft determinations have not been subject to a detailed risk assessment by the AER and I strongly encourage the AER to undertake detailed risk assessments of the broader impacts of these determinations in their current form."

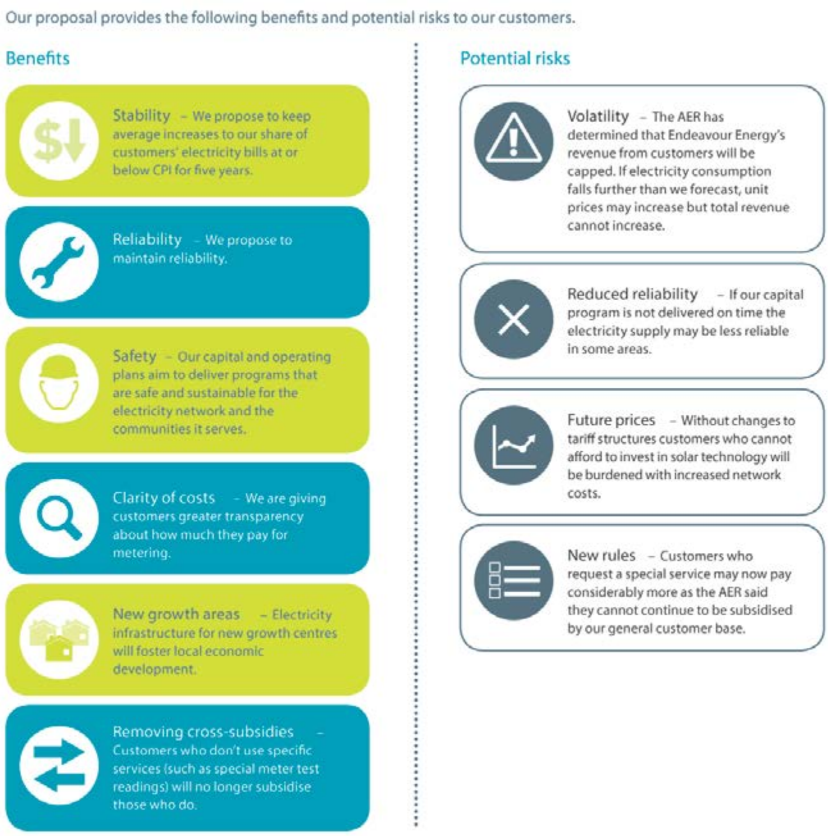
We share these concerns and we will not increase, as proposed by the AER, our risk profile for: employee and public safety; vegetation and bushfire risk management; and life support customers on local distribution networks. We will maintain an ordered priority for: Safety; Reliability; and Affordability.

Documents do not demonstrate key risks and benefits

The AER stated that Endeavour Energy's overview and its proposal more broadly do not sufficiently detail how Endeavour Energy has engaged and sought to address these concerns or describe the key risks and benefits for electricity consumers.

In response we note that the following information was provided as part of our initial proposal. This has been included in our plain English summary, on our website and been presented during consumer forums.

Figure 2a: Information provided to stakeholders regarding benefits and risks of our proposal



[74] Commissioner – Fire and Rescue NSW, Letter to CEO of Networks NSW, December 2014, p2.

[75] Commissioner - NSW Rural Fire Service, Letter to CEO of Networks NSW, December 2014, p2

2.3.3 Consumer engagement and AER's decision making

It is apparent from the AER's draft determination that the views of customers has impacted the AER's decision making in two respects:

- The AER's consideration of whether our proposed capex and opex satisfied the capex and opex criteria in the Rules.
- The AER's overall decision. In particular the AER has expressed a view that its determination is an overall decision and must be considered as such. In this respect it considered that consumer preferences should also be reflected throughout the proposal.

AER's decision making for capex and opex constituent decisions

It is not clear that the AER's decisions to reject and substitute our proposed capex and opex have been based on its assessment of our customer engagement process or findings. For capex, the AER stated:

> *"We have had regard to the extent to which Endeavour Energy's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Endeavour Energy. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Endeavour Energy's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified."*

The AER's draft decision on opex seems to place some weight on customer engagement findings presented by Endeavour Energy, however it is not clear whether the AER's considerations impacted its decision to reject our proposed opex.

> "*We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they* factor *in the needs of consumers. We have considered the concerns of electricity consumers as identified by Endeavour Energy– particularly those expressed in the consumer-focussed overview provided as an attachment to its regulatory proposal. For example, a clear theme present in this document is that customers consider electricity prices are too high*."

We consider that our initial proposal has already taken this view into account when we developed our total forecast opex and capex for the 2014-19 period. At the time we recognised the need to incorporate significant efficiencies into our forecast such that we can continue to provide the safe and reliable services valued by our customers at the lowest cost. As we discuss in Chapters 5 and 6, we have made revisions to our proposed opex and capex to reflect latest information on the efficiencies we expect to achieve in the 2014-19 period.

AER's consideration of customer preferences as part of its overall decision

While it is unclear how the AER's constituent decisions for opex and capex have incorporated the engagement activities and findings from customer engagement, the AER has been clear that customer preferences have been important in its overall draft distribution determination. The AER stated:

> *"We acknowledge that Endeavour Energy has had a short amount of time to implement our consumer engagement guideline for network service providers. Endeavour Energy has undertaken engagement strategies. However, based on feedback from stakeholders, Endeavour Energy has not presented compelling evidence of how its proposal adequately incorporates the views and concerns of its customers. This manifests in a number of aspects. First, the number and breadth of submissions received that do not support Endeavour Energy's proposal as being in the long term interests of consumers. Second, the range of issues that are important to consumers and stakeholders raised in their submissions but not reflected in Endeavour Energy's regulatory proposal. For example, efficient demand management options instead of capex.*
>
> *Based on the submissions in response to Endeavour Energy's regulatory proposal and our consultation with consumers, we are not satisfied that Endeavour Energy's proposal adequately reflects the views of consumers. In particular, consumers have indicated that they were not offered opportunities to express preferences for service standards and costs which were backed by pricing impact information. Consumers were also concerned that Endeavour Energy did not disclose its*

> *intention to depart from key aspects of our rate of return guideline which was developed with extensive stakeholder consultation."*

The AER's statements demonstrate that it has taken a very narrow view of the long term interest of customers. Rather than assessing whether our proposed expenditure provides for a level of safety and reliability valued by customers, the AER has instead sought to focus on customers' preferences for lower price, citing the 'unprecedented level of consumer participation' as a foundation for its decision. Endeavour Energy supports the increasing participation of consumers in the regulatory process, including stakeholders representing different consumer cohorts.

However, Endeavour Energy believes the AER has placed too much emphasis on unsubstantiated claims made in many of the responses to our initial proposal. Endeavour Energy does not believe it is reasonable for the AER just to accept the making of submissions as evidence to reject its findings of consumer views and concerns. The submissions themselves need to present evidence to support an alternative position of consumer views and concerns. These submissions contain no such basis of fact to reject Endeavour Energy's extensive work to test consumer concerns.

We have already addressed the concerns raised by two councils. Three submissions were made on behalf of major energy users or electricity generators, another submission was made by a metering business, a demand management business and the industry association representing the renewable energy industry.

The five remaining submissions were made by consumer or welfare groups, a group that advocates on environmental issues and the Consumer Challenge Panel set up by the AER.

There are some valuable insights in these last five submissions, however there are also a number of short comings which makes it unreasonable for the AER to reject our proposal based on them. Most importantly, the submissions from the CCP and others base their findings on our consumer engagement activity and practices, on the AER's Consumer Engagement Guidelines.

The consumer engagement undertaken by Ausgrid, Endeavour Energy, Essential Energy and ActewAGL in preparing their final regulatory proposals has been evaluated in the context of the AER Consumer Engagement Guidelines for Network Service Providers. (CCP p.6)

As previously stated these guidelines were only published five months before Endeavour Energy's regulatory proposal was submitted. In the guidelines the AER stated:

> *"…service providers will need some time to develop and implement robust and comprehensive engagement strategies and approaches." (page 12)*

The AER's assessment on an overall revenue requirement has been influenced by these submissions and therefore by doing so ignores and contradicts its own guidelines when making its determination. This is fundamentally unreasonable and lacks good faith, as asked for by the AEMC.

Endeavour Energy notes that the AER also states that it received a submission from an agricultural group on our proposal and that this helped form its views on whether we had reflected consumer concerns.

Endeavour Energy cannot find any record of this submission to its regulatory proposal.

The AER also stated that it was not satisfied that our initial proposal reflected the views of consumers based on its own consultation with consumers.

Based on information in its draft determination, the AER conducted the following engagement activity with consumer groups or stakeholders, in addition to considering submissions and the views of the Consumer Challenge Panel:

- Hosting a public forum on 10 July, 2014
- Metering workshop on 11 September, 2014

- Meeting with the NSW Public Interest Advocacy Centre and other stakeholders to discuss their submissions in detail

By its own standards of engagement, this level of participation to seek views on our proposal appears inadequate and could not lead to an effective judgement on whether our proposal reflects consumer views. We contrast this engagement with Endeavour Energy's detailed level and breadth of consumer engagement detailed in our initial submission and this revised submission.

View of customer stakeholders

AER's Consumer Challenge Panel submission

Endeavour Energy values the role of a Consumer Challenge Panel, however we have serious concerns about the robustness and foundation of the advice the CCP sub-panel 1 has provided to the AER.

The CCP has rejected evidence based findings on consumer views and concerns and therefore recommended to the AER that it rejects our revenue proposals. The CCP has done so based on unsourced advice and anecdotal evidence.

> *"The sub-panel has received information from consumer representatives, which suggests that the consumer engagement undertaken by the NSW distribution businesses has been ineffective to date."*[76]
>
> *Anecdotal evidence and the views of some consumer organisations suggests to the sub-panel that consumers may prefer lower prices even if that meant a greater risk of reduced reliability."*[77]

Endeavour Energy does not believe it is credible for the AER to accept anecdotal evidence and reject our evidence based findings on consumer preferences. We note we have found no facts presented to show consumer preferences as suggested by the CPP.

We do note that there is widespread acknowledgement in submissions on our proposal, that Endeavour Energy has embarked on extensive consumer engagement activity.

The CCP also rejects the findings of Endeavour Energy's research, based on the methods used in the research. We considered this to be unwarranted. It suggests that this is reason enough to reject our findings on consumer preferences, and substitute untested views.

The general finding from Endeavour Energy's research was that customers did not want to pay additional amounts to improve the reliability of their power supply. They in turn preferred to maintain their existing levels of reliability, without having to pay more. They also did not prefer worsening reliability as a trade-off for a price reduction. Endeavour Energy further tested these views in other engagement forums, including three deliberative planning workshops held across its franchise, and in further statistically valid research using choice modelling techniques.

Residential and small business customers confirmed these findings and supported our plans to drive further efficiencies while maintaining current reliability and safety standards.

We also note that the CCP refers Endeavour Energy to the survey techniques of Western Power Distribution (WPD) as an example of how different survey techniques could have provided evidence to support its alternative view that consumers are willing to pay less for reduced reliability:

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[76] CCP submission to AER re: NSW DNSP's, "Jam Tomorrow", August 2014, pg 8

[77] CCP submission to AER re: NSW DNSP's, "Jam Tomorrow", August 2014, pp 11-12

"This indicates that there is precedence for our view that consumers may prefer lower prices for reduced reliability, where the research is according to best practice."[78]

Advice received from WPD about these findings from the CCP states that it was misleading for the CCP to make this claim. It explained that while about 15% of its customers voted for a deterioration of services via the WTP research, the remainder in fact supported the maintenance or improvement of network service levels.

It went on to explain that further road testing of consumer views via qualitative assessment showed that almost all participants supported the maintenance of customer and network services at present levels, rather than a deterioration of services for a price reduction.

"We did not elect for any option that led to deterioration in service. That's because from day one, stakeholders told us that their number one priority above all others was that current service standards should be, as a bare minimum, maintained."[79]

The CCP stated the WPD research conclusions were a possible source of alternative evidence to reject Endeavour Energy's findings on consumer concerns and preferences:

"…we consider that the AER will need to take into account other evidence of the views of consumers in reaching its determinations in respect of customer willingness to pay for specific levels of reliability."[80]

We strongly contend that this finding is incorrect, and that the WPD consumer engagement program actually supports our findings on consumer views and preferences.

Public Interest Advocacy Centre

Endeavour Energy is pleased to receive and review the submission to its initial proposal from the Public Interest Advocacy Centre. We will address here its main findings and recommendations in regards to customer engagement.

We support PIAC's view that network businesses could submit an additional two-page summary of our regulatory proposal. We would be happy to consult with PIAC and others on how this summary could be developed.

We also support the view from PIAC that a greater attempt by both network businesses and consumer groups to engage and work collaboratively ahead of the 2018 regulatory proposals can result in a more accessible and sustainable network services.

We also agree that network businesses should not shy away from constructive criticism of their operations and should produce documents with this in mind. We note that our digital strategy for consumer engagement published on our website and attached to this revised submission, is based on the premise that new forms of communication such as Facebook are open channels for discussion and criticism. We have encouraged this constructive criticism and used it to help inform our submission.

The joint Your Power Your Say Facebook campaign was designed to overcome natural barriers for consumers to participate in conversations about their electricity supply.

An analysis of the campaign found that it had reached almost 1.6 million Facebook users and had resulted in almost 62,000 interactions with consumers across a range of issues associated with their electricity supply. These topics included: pricing; reliability; street lighting; electricity tariffs; demand management; solar generation; and customer communication.

[78] CCP submission to AER re: NSW DNSP's, "Jam Tomorrow", August 2014, pg 12

[79] Western Power Distribution, email to Ausgrid 17 December 2014

[80] CCP submission to AER re: NSW DNSP's, "Jam Tomorrow", August 2014, pg 12

The most recent findings of this campaign are at Attachment 2.04 “Your Power Your Say Facebook Activity Report - November 2013 to October 2014”. This attachment demonstrates wide-ranging views on many topics of interest. This forum has allowed consumers to raise their own concerns and ideas in what has been a successful two-way engagement process. Analysis and summary reports of this campaign are listed in the customer engagement section of the Endeavour Energy website.

Lastly, we agree with PIAC that as consumer engagement becomes more sophisticated, that NSW network businesses should seek to engage with their customers about the dollar impact of, for example, reducing reliability standards. Endeavour Energy engaged further extensive research based on choice modelling techniques to help achieve this. We have presented this research and intend to test its main findings via further consumer workshops.

There are a number of comments from PIAC in its submission that Endeavour Energy not does support.

Endeavour Energy’s plain English submission was a requirement of recent rule changes put forward by the AEMC in 2012. Endeavour Energy’s internal staff wrote this document and had the document designed by graphic artists to ensure it was easy to read and accessible. This is the same graphic artist employed by the AEMC to make their communication plain and accessible for consumers.

PIAC is free to put its view that some businesses, politicians or advocates use marketing firms to create spin, instead of substance in these types of documents. However, this is not the case for Endeavour Energy.

Our Plain English Customer Summary contains all the key highlights of our initial proposal, regardless of whether it portrays us in positive or negative light.

PIAC is also of the view that Endeavour Energy and other network businesses did not respond to concerns that low income households were struggling to pay electricity bills and stay connected to the electricity network. Endeavour Energy’s CEO Vince Graham has consistently and publicly expressed the view that more needed to be done to reduce our costs to help keep pressure off future network electricity price increases. Indeed, this understanding has underpinned the core business plan of Endeavour Energy for the past three years.

In particular, we have also delivered the NSW Government’s reform program. This is particularly important because this program directly funds additional rebates to low income households and families struggling with increasing electricity costs.

We note the success of this program in a media statement from the NSW Government that states that more than 780,000 participants had received the Low Income Household rebate (see Attachment 2.05).

In response to concerns expressed by PIAC about accessibility to our regulatory proposal, we note that we deliberately published our initial proposal and full list of attachments on 2 June, 2014, several weeks before it was formally made available by the AER.

We also wrote to consumer groups and other stakeholders to inform them it was available, subject to being passed as a complying document by the AER. This was done to ensure stakeholders had as much time as possible to review and comment on documents.

We produced plain English summary documents of the key components of our business operations, including comparisons with past periods, to ensure customers were equipped with key information to make proper judgements on our regulatory proposal. They were each published on Facebook and have been published on our website. They are attached to this revised proposal.

We also note that PIAC has participated in face to face and written engagement activities since the publication of our initial proposal. We are keen for this relationship and engagement to grow as part of our genuine and ongoing commitment to greater consumer engagement.

2.4. Customer engagement since our initial proposal

Customer engagement activities were a significant input in developing our initial proposal. We have reviewed the AER's draft decision and assessed recent activities we have performed since the initial proposal. The findings align with our initial proposal, and raise concerns with the AER's draft decision.

2.4.1 Further engagement activities

The attachments supporting this chapter outline in detail how we have engaged customer and stakeholders since May 2014. These tables include the stakeholders engaged, the purpose of these activities and the key outcomes of consultation. Of note are the following:

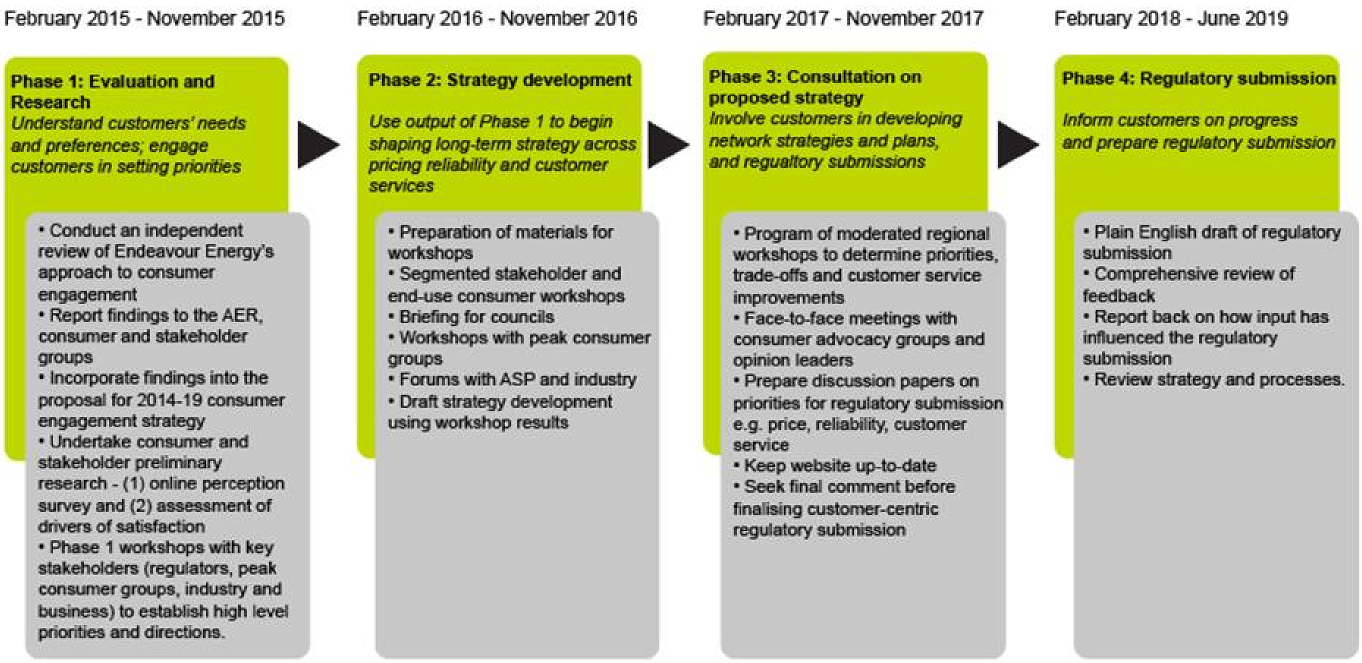
1. As previously outined we undertook web-based 'choice modelling' whereby 1000 randomly selected residential consumers were surveyed to attain consumer priorities for different prices in relation to: reliability; power restoration; emergency response; asset maintenance; and vegetation management. (see Attachment 2.03).
2. Conducted our third consumer engagement forum for the year (see Attachment 2.06). The forum engaged 'mums and dads' and small business owners and outlined our strategic objectives and investment plans for the next five years. We also attained consumer preferences with regards reliability; power restoration; asset maintenance; and vegetation management.The main themes were:
    - Attendees were generally happy with the level of reliability and wanted the current level of reliability to be maintained.
    - Approximately two-thirds of attendees were not willing to trade a decreased cost for electricity for decreased reliability.
    - Most attendees wanted steady changes in their electricity bills and wanted to avoid a boom-bust cycle of price changes.
3. Met with councils on our public lighting proposal. Endeavour Energy understands councils welcome our plan to contain our share of total public lighting costs to no more than CPI for the next five years. We have conducted positve meetings with Western Sydney Regional Organisation of Councils - which represent 90% of the councils in our network - to support new technology options such as LED lighting.
4. Held forums with the National Electrical Association (NECA) and Accredited Service Providers (ASPs) to discuss the regulatory regime, pricing of metering and ancillary facilities and the AER's changing of the regulatory regime. (see Attachment 2.02). The majority of comments on fees have been generated at the recent seminars. These comments were mainly around: the size of the fee increase; and requests for adequate and timely notice on the final prices once approved by the AER. Endeavour Energy has a project commencing this month to prepare for the changes to and the additional AER fees that will apply from July 2015. This will allow us to provide timely and detailed advice to ASPs.

2.4.2 Our long term customer engagement plan

Endeavour Energy is dedicated to continually improving its engagement activities and ensuring ongoing alignment with AER Consumer Engagement Guidelines. The results of this engagement will continue to drive business decisions which place the customer first. We also want to ensure our processes are aligned with best practice principles for customer engagement.

Our Customer Engagement Plan 2014-19 draft (Attachment 2.01) will ensure we develop a robust, customer-centric proposal for the 2019-24 regulatory period. A timeline of this plan is shown at Figure 2b.

Figure 2b: Long term customer engagement plan



Conclusion

Endeavour Energy has clearly outlined engagement activity which is based on the AER's Consumer Engagement Guidelines, despite those guidelines being published only months before our initial submission was due to the AER. Our consumer engagement activity was based on a strategy endorsed and led by our senior leadership team, based on objectives, principles and processes consistent with the AER's guidelines.

Our engagement activity identified consumer views and priorities described in our proposals. Importantly, Endeavour Energy has used an evidence based approach to determine customer views, where other stakeholders have relied on anecdotal feedback and claims which are at best generic and unsubstantiated.

We are committed to building on the successes and learnings to date to drive better outcomes for consumers across all aspects of our business.

We believe we have demonstrated that the AER has formed an unreasonable view in rejecting our representation of consumer concerns. It has done this based on anecdotal evidence, errors of fact and misrepresentations.

3 SERVICES AND PRICE CONTROLS

Summary

We have revised our initial proposal to incorporate the AER's draft decision for classification of services. We have also revised our proposal to incorporate many elements of the AER's draft decision on control mechanisms. We have not revised our proposal for the AER's decisions on incentives.

The AER was required to make a number of important decisions before we submitted our substantial proposal. This included decisions on how to classify the services we provide, the control mechanisms that would apply, and the incentive mechanisms we would be subject to in the 2014-19 period.

We have revised our proposal as follows:

- Classification of services - We have revised our proposed service classification to adopt the AER's minor definitions and re-grouping of services. We have also revised our proposal to align with the AER's decision to re-classify load control devices to alternative control services where these are integrated with a meter. This is discussed in section 3.1 of this chapter.
- Control mechanisms - We have revised our proposal to amend the formulae for elements of the AER's decision on the control mechanism for standard control services. This is discussed in section 3.2 of this chapter.
- Incentive schemes - We consider that unless the AER accepts our revised capital and operating expenditure proposals, that the Efficiency Benefit Sharing Scheme, the Capital Expenditure Sharing Scheme and the Service Target Performance Incentive Scheme should not apply for the reasons set out in this chapter.

3.1. Service classification

Clause 6.12.1(1) of the NER or Rules requires the AER to make a decision on the classification of the services provided by Endeavour Energy. The AER's decision on classification is constrained by the Rules which require the AER's decision to be the same as that of the F&A paper unless the AER considers there are unforeseen circumstances justifying departure from the classification.

The AER published its service classification decision in Stage 1 F&A paper in March 2014. Our proposed classification of services for the 2014-19 period essentially adopted the AER's classification with a few proposed clarifications to provide more clarity on the service descriptions contained in the AER's Stage 1 F&A paper. These were:

- Specify network augmentation as part of network services.
- Provide clarity around the classification of emergency recoverable works, particularly in the case where we are not able to identify the parties liable for the damage or are not able to recover from the identified parties the cost of repairing the damages.
- Minor clarification around the description of certain ancillary network services.

The AER's draft decision on classification of services largely conforms to its Stage 1 F&A paper. The AER has accepted minor clarifications set out in Endeavour Energy's initial proposal , and has re-organised the grouping of services. The two substantial departures from the Stage 1 F&A paper relate to the re-classification of load control and exit fees for metering services.

In the sections below we set out the reasons why we have revised our proposal to incorporate the changes set out in the AER's draft determination in respect of classification of services. We have accordingly adopted the changes to the classification of services set out in Table 13.1 of the AER's draft decision.

3.1.1 Minor clarifications and re-groupings

The AER incorporated the clarifications proposed by Endeavour Energy outlined above. In addition, the AER re-organised the grouping of services, with no change to the classification of these services and service groups.

We have revised our proposal to incorporate the changes required by the AER's draft decision on the basis that they do not represent a material departure from its decision.

3.1.2 Changes to classification of load control

In its draft decision, the AER amended its definition network services and metering services group to effect its decision on the classification of 'load control services'.[81] Effectively, the AER's decision means that when the load control functionality is within the meter, it is classified as alternative control services. In other cases, the load control device is a standard control service.

We have revised our initial proposal to accept the AER's draft decision to re-classify load control services. The AER's approach is consistent with the methodology we used to prepare our regulatory proposal, and therefore we have not made a revision to our prices for metering. We had included the implied incremental costs of the load control device when deriving the prices for our metering services.

However, we have not sought to allocate costs associated with the load control system. Our reasons were that the incremental costs were not easily identifiable, and likely to be a small percentage of the costs of operating the meter. Further, the exit fee for the meter provided a means of recovering the sunk investment in the load control device, if a customer sought a new meter from an alternative provider.

3.1.3 Changes to classification of metering services

The AER decided that a new standard control service be created to allow DNSPs to recoup the stranded costs created by competition at the time a customer obtains an alternate metering service provider. The existing asset base would be recovered from annual metering charges; if the customer leaves an amount (equal to the residual value of the asset) will be recovered via an adjustment to standard control services.

In Chapter 8 we note our reservations with the AER's decision due to administrative burden. Nevertheless we have revised our proposal to incorporate the change required by the AER. This has resulted in consequential revisions to our schedule of metering prices and to our proposed control mechanism.

[81] The AER included "load control" in its description of "Operating the network for distributor purposes" (which fall in the Network Services group) and also included "load control devises in its description of "Type 5 and 6 metering provision, maintenance, reading and data services" (which fall in the Metering Services group).

3.2. Control mechanisms

Clause 6.12.1(11) and (12) of the Rules require the AER to make a decision on the form of the control mechanisms and the formula that give effect to the control mechanisms for standard control and alternative control services respectively. The form of the control mechanisms must be as set out in the relevant F&A paper. The formula must also be the same, unless unforeseen circumstances justify departure.

The AER published its control mechanism decision in Stage 1 F&A paper in March 2014. The AER determined that the basis of control for standard control services was to be a CPI-X form consistent with the Rules, and the form of control was to be a revenue cap. The AER also set out its proposed approach to the formulae that give effect to the control. The AER stated that it would confirm a basis of control for alternative control services in making its determination, and that the form of control would be caps on the prices of individual services. The AER also set out its proposed approach to the formulae that give effect to the control.

In our initial proposal, we noted that we are not able to propose a change to the form of the control mechanisms, as the Rules require that they must be as set out in the relevant F&A paper. However we sought clarification from the AER on the formulas to apply:

- For standard control services, we sought clarity and proposed our position on inflation, cost of debt updates, and the cost of repairing the network for damage caused by a third party when the amount was unrecoverable.
- For alternative control services we sought a schedule of fixed prices and a price path in the remaining years.
- We also proposed our position on the true-up adjustment for the transitional year.
- The AER's draft decision makes a substantial change in the control mechanism for standard control services in relation to its proposed treatment on exit fees for metering services. The AER has also provided clarity on the control mechanism it determined to apply to alternative control services, and set out how it will incorporate the 'true up' adjustment for the transitional year.

Standard control services formula

In the points below, we note the AER's draft decision with respect to the formula for the control on standard services, and set out where we have revised our proposal to incorporate changes required by the AER's decision:

- **Cost of debt adjustment** – The AER decided that the adjustment for the annual cost of debt adjustment should be part of the X-factor, rather than a separate W-factor. We have revised our proposal to incorporate the change required in the AER's draft decision.
- **Adjustment for unrecoverable third party damange** – The AER decided not to include an E factor to allow for the updated costs of repairing the network for damages caused by third parties that are unrecoverable. We have revised our proposal to incorporate the change required by the AER.
- **Adjustment for metering exit fees in the B-factor** – The AER has decided to create a new standard service to recoup residual metering costs when a customer exits the services we provide. The AER has specified that the B-factor will include the residual metering costs. We have revised our formula to incorporate the AER's draft decision.
- **Distribution Use of System (DUOS) under-over account (included a tolerance limit)** – The AER rejected the inclusion of DUOS over and under as part of the control mechanism, and has now included this as part of the compliance with control mechanism decision. We reject the AER's draft decision. We discuss this further in Chapter 9 including our reasons why a tolerance limit should be placed on DUOS over and under acccounts.
- **Pass through** – The AER has included pass through amounts as part of the B-factor. We have revised our proposal to incorporate the change required by the AER.

Our revised proposal for the standard control services control mechanism is discussed further in Chapter 9 and is set out in Attachment 9.01.

Alternative control services formula

The AER have set out a formula for alternative control services. We have revised our proposal to incorporate the change required by the AER. Our revised proposal is to adopt the AER's control mechanism for public lighting services as specified in 16.7.1 of the AER's draft decision; metering services as specified in section 16.7.1 of the AER's draft decision; fee based ancillary services as specified in section 16.5.1 of the AER's draft decision; and quoted ancillary services as specified in section 16.5.1 of the AER's draft decision.

3.3. Application of Incentive schemes

Clause 6.12.1(9) of the Rules require the AER to make a decision on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply to the DNSP. The Rules require the AER to set out its proposed approach in Stage 2 of the AER's F&A paper.

The AER published its control mechanism decision in Stage 2 F&A paper in January 2014. The AER determined to apply an EBSS, CESS and STPIS and Demand Management Incentive Scheme (DMIS) in the 2014-19 period, but that certain modifications would apply in the transitional year. The AER decided not to apply a small scale incentive scheme.

In our initial proposal , we proposed that the incentive schemes identified by the AER apply for the 2014-19 period. Our proposal sought modifications to the application of certain incentive schemes in the transitional year (2014-15) and provided further proposals on the design and parameters of each scheme.

The AER has made a number of changes to its proposed position on the application of incentives as set out in its F&A paper.

Endeavour Energy considers that unless the AER accepts our revised capital and operating expenditure proposals, that the Efficiency Benefit Sharing Scheme, the Capital Expenditure Sharing Scheme and the Service Target Performance Incentive Scheme should not apply for the reasons set out below.

3.3.1 Efficiency Benefit Sharing Scheme in 2014-19 period

The EBSS provides a continuous incentive for the DNSP to achieve efficiency gains in its operating expenditure. In its F&A paper, the AER decided that for the transitional year, the EBSS applicable to the current 2009-14 period, as modified to align to version 2 of the EBSS (the modified EBSS), will apply as if the transitional year was the first year of the subsequent regulatory control period. For the 2015-19 regulatory period, the AER specified that version 2 of the EBSS will apply to Endeavour Energy.

The AER's draft decision is that no expenditure will be subject to the EBSS in the 2015–19 regulatory control period. The AER made this decision because of its forecasting approach to opex and the likely incentives Endeavour Energy already faces to improve its efficiency. The AER noted that this also means that no expenditure will be subject to the EBSS in the 2014-15 regulatory period.

Our contention is that if the AER makes the correct opex decision, it would have no need to suspend the application of the EBSS and it is inconsistent with its previously proposed approach. We consider that the AER's reasoning demonstrates that the substitute forecast opex is unachievable, and there would be a high risk of substantial penalties if an EBSS was applied. As we demonstrate in Chapter 6 of this revised proposal, the AER's responsibility is to set an efficient and prudent opex that meets the opex objectives. If the AER make such a decision, then an EBSS incentive would provide a symmetrical incentive. Based on our revised opex, we propose that the EBSS incentive framework continues to apply. For the 2009-14 carry-over amounts we have not revised the calculation included in our initial proposal.

If the AER, however, decide to not accept our proposal and to substitute a lower (unachievable) amount, which we consider would be contrary to the Rules, then an EBSS would not provide a symmetric incentive, and therefore should not apply.

In addition, the AER now seeks to exclude carry overs of efficiency gains and losses caused by changes in provisions in the draft decision for Endeavour Energy for the 2015-16 to 2018-19 subsequent regulatory period by claiming that provisions are an accounting treatment and do not actually represent an expenditure (as required by clause 6.5.8(a) of the NER) from which an efficiency gain or loss can be determined. That is, there is a degree of artificiality to such costs.

There is no rule that explicitly provides discretion for the AER to retrospectively introduce additional excluded cost categories for the EBSS or to revise/review adjustments, and there are strong arguments that the AER is not entitled to do so.

We consider that such a retrospective exclusion would be contrary to the purpose of incentive based regulation and secondly would not be consistent with "fair sharing" of efficiency gains and losses under the EBSS. In addition, the February 2008 EBSS that applied to Endeavour Energy in the previous regulatory period does not provide for the AER to exclude an additional cost category after the relevant final determination. That is, the exclusion of an additional category of costs as uncontrollable was an option given to Endeavour Energy prior to the regulatory period in which they would apply and not the AER after the event.

3.3.2 Capital Efficiency Sharing Scheme in 2014-19 period

The CESS provides reward/penalty for efficiency gain/loss with respect to capital expenditure. The AER published its capital expenditure incentive guideline in November 2013 which sets out the CESS.[21]

In its distribution determination for the transitional year (i.e. 2014-15), the AER specified that no CESS applies, consistent with the requirement of the Transitional Rules. The AER proposes to apply its CESS in the 2015-19 regulatory period in accordance with its published guidelines.

The CESS as set out in the AER's November 2013 capital expenditure incentive guideline provides reward/penalty for efficiency gain/loss with respect to capital expenditure. In its determination for the transitional year (i.e. 2014-15), and consistent with the Transitional Rules, the AER specified that no CESS would apply in 2014-15. The AER proposes to apply its CESS in the 2015-19 regulatory period in accordance with its published guidelines.

Endeavour Energy's initial proposal was to apply the CESS in the 2015-19 regulatory period, consistent with the AER's proposed approach as stated in the AER's Stage 2 F&A paper. The AER's draft determination is consistent with the F&A paper and our initial proposal, and on this basis we have not revised our proposal.

Consistent with the approach to EBSS, if the AER decides to not accept our capital expenditure proposal and instead substitutes a lower amount, we consider that a CESS would not provide a symmetric incentive and therefore should not apply.

3.3.3 Service Target Performance Incentive Scheme in 2014-19 period

The STPIS provides incentives to improve reliability and customer service standards. In the AER's F&A paper it stated that it would not apply a scheme to the transitional year, but would apply its current national scheme for distributors for the 2015-19 period.

Our proposal agreed with the AER applying a scheme from 2015-16 onwards, and set out a revenue of risk of 2.5%. We also provided detailed information on the design of the STPIS including the parameters that should apply, the revenue at risk for each parameter, the targets that should apply, and other matters such as the calculation of the major event day threshold.

The AER's draft decision has applied a STPIS from 2015-16 onwards with a revenue at risk of 2.5% consistent with our proposal and the F&A paper. The AER has also accepted our proposed revenue at risk for each parameter and our customer service performance target.

The AER however, has not accepted our proposed reliability targets. Attachment 5.04 provides detail on our reliability capex and our STPIS proposal. It sets out why we have not revised our proposal for the AER's draft decision on the reliability parameters. We do not agree with the AER's approach to set a target which is below our current performance based on performance trends observed on Ausgrid's network. We also believe that it is an incorrect supposition that investment undertaken in the 2009-14 period will have an impact on our targets in the 2014-19 period. Endeavour Energy believes that the AER should have based its assessment on our own average performance over the last five years, rather than set a target which is significantly above our current performance based on trends in an unrelated and dissimilar network.

Additionally, it appears inconsistency exists in the AER's calculation of incentive rates. Specifically, the AER has calculated the average energy consumption using the 2014-19 years, but have used the 2015-19 years to calculate the average smoothed revenue. We consider that for the purposes of 3.2.2(h) and (i) of the STPIS, that the 'regulatory control period' is the 2015-19 period. Therefore, the AER should amend the average energy consumption calculation to align with this period in its final decision.

If the AER were to impose their adjustment to our STPIS reliability targets and their proposed real reduction to our future capital and operating expenditure programs of 39% and 23% respectively , against our initial proposal, we do not consider that we would be in a position to meet our current reliability targets. We have sought advice from Jacobs Group Australia in relation to the reliability and STPIS impacts of the draft determination (Attachment 1.10). Modelling by Jacobs confirmed that in those circumstances reliability would materially worsen compared to previous forecasts, with further degradation in following regulatory periods.

Jacobs found that Endeavour Energy's SAIFI would increase by 1.3% between the base year of 2014-15 and 2020, with SAIDI worsening by 11.6% over the same period.[82] They also found that by 2025 SAIFI would worsen by 2.7% and SAIDI by 13.1%. Jacobs noted:

> *"The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a ten year period"* [83]

As there were more potential sources of unreliability which were discussed but not quantified (including repex impacts), given the timeframe available, Jacobs also noted that

> *"For the various reasons discussed, it is believed that this analysis of the impact of the Draft Decision underestimates the negative impact (increased frequency) of the impact of outages on the network."*[84]

Endeavour Energy maintains that a STPIS should apply to the 2014-19 period provided reasonable expenditure allowances are provided that are consistent with maintaining existing service levels. Endeavour Energy has only revised the STPIS proposal to recalculate the 2009-14 major event days utilising the alternate normalisation methodology in our initial proposal which was accepted by the AER. The resulting excluded major event days differ only slightly to those provided in the AER's draft determination STPIS Attachment 11. See Attachment 5.04 to this regulatory proposal for further details.

To be clear, a STPIS incentive framework in the 2014-19 period based on the AER's draft determination would not provide a symmetric incentive. Using the analysis referred to above, Jacobs' further modelling of STPIS

[82] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p4

[83] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p3

[84] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p14

impacts indicated that assymetrical STPIS penalties from 0.56%, rising to 0.67%[85] over the regulatory determination period, would result from the AER's draft determination if implemented. Endeavour Energy considers that unless the AER accepts our revised capital and operating programs; the STPIS should not apply.

3.3.4 Demand Management Incentive Scheme

Demand management provides opportunities to efficiently reduce network expenditure. In the F&A paper the AER's position was to continue applying the Demand Management Incentive Allowance (DMIA) at the same scales as currently applied to NSW DNSPs, but to discontinue Part B of the scheme which related to compensation for foregone revenue. This allowance is provided as a fixed amount of additional revenue at the commencement of each regulatory year, and supports learning and development of demand management activities.

Our initial proposal supported the AER's approach. Our proposal noted that the Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. Our proposal was that the AER should apply the incentive scheme if a Rule change is implemented in time for our final determination, subject to consultation with Endeavour Energy.

The AER's draft decision is consistent with the F&A Paper and our initial proposal, and on this basis we have not revised our proposal.

3.3.5 Small scale incentive scheme

The AER's F&A paper decided not to apply the small scale incentive scheme. We supported the AER's decision in our initial proposal. The AER's draft decision not to apply the scheme is therefore consistent with the F&A paper and our initial proposal, and on this basis we have not revised our proposal.

[85] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p23

4 BUILDING BLOCK PROPOSAL

Summary

The AER did not accept many of the elements of our building block proposal. We have made a number of revisions to our building block proposal to incorporate changes to underlying inputs, which have a consequential impact on proposed revenues and prices.

The AER did not accept many of our building block inputs. For this reason the AER has not accepted our proposed annual revenue requirements and X-factors.

We have reviewed the AER's draft decision, and have considered whether any revisions are necessary. We have made revisions to our building block inputs, many of which relate to our revisions to forecast capex, opex and allowed rate of return. We have also reviewed the AER's draft decisions on opening asset base, regulatory depreciation, and corporate income tax, and revised where we consider necessary. We have not revised our proposed EBSS carry over amount. The resultant building blocks are identified below:

Table 4.1: Annual revenue requirement building blocks (Unsmoothed)

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on capital	493.8	526.7	552.4	572.9	592.8	**2,738.6**
Return of capital	62.8	72.2	82.8	86.7	92.9	**397.4**
Operating expenditure	300.1	321.4	321.5	325.2	329.1	**1,597.2**
Cost of corporate tax	65.9	65.2	71.7	72.0	74.5	**349.2**
EBSS Adjustments	98.7	33.7	42.8	34.6	0.0	**209.8**
DMIS Revenue	0.6	0.6	0.6	0.7	0.7	**3.2**
Metering and ANS costs	62.5					**62.5**
DMIA carry-over		-3.0				**-3.0**
Total (Unsmoothed)	**1,084.4**	**1,016.8**	**1,071.8**	**1,092.1**	**1,090.0**	**5,355.0**

The revisions we have made to our building block inputs have resulted in consequential revisions to our revenue requirements and X-factors. Our revised proposal on these matters is set out below. We have also made revisions to our annual revenue and X-factors. This is set out in section 4.4 of our revised proposal.

Table 4.2: Indicative annual and smoothed revenue requirements

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Unsmoothed revenue	1,084.4	1,016.8	1,071.8	1,092.1	1,090.0	**5,355.0**
Smoothed revenue	949.5	1,058.6	1,092.2	1,123.5	1,167.1	**5,390.8**

Table 4.3: X-factors used to smooth revenues (% change in real revenues), excluding inflation

%; Real	2014-15	2015-16	2016-17	2017-18	2018-19
Distribution X-factors	8.74%	-8.78%	-0.65%	-0.36%	-1.35%

Note: A positive revenue X-factor denotes a real revenue reduction.

In section 4.4.3 we provide the indicative prices for this revised proposal compared to our initial proposal and the AER's draft decision. However, it should be noted that this price path will be impacted by the AER's transitional decision, which has effectively locked in revenue well below the level we propose for the 2014-15 year. This has meant that we will need to recover the residual amount in the 2015-16 to 2018-19 period as discussed in section 4.4.2.

We also note that the:

- AER did not accept our proposed nominated pass through events. We have reviewed the AER draft decision but do not consider there is a need to revise our proposal.
- We concur with the AER's draft decision to apply forecast depreciation when establishing the regulatory asset base (RAB) in the 2014-19 period.

4.1. Initial proposal

In our initial proposal, we identified the building block components we have used to calculate the annual revenue requirement for each year of the regulatory period,[86] consistent with the Rules requirements. The building blocks relate to the following types of costs:

- Return on capital. We receive an allowance for a return on capital. This is to repay our debt and provide a reasonable return on equity for the funds we borrow or raise through debt and equity to fund investments. The calculation of the return on capital is based on key inputs including the value of the opening asset base, the allowed rate of return and forecast capital expenditure.
- Return of capital. We receive an allowance for a return of capital (depreciation). The calculation of the return of capital is based on key inputs such as the value of the opening asset base and the remaining lives of assets and is calculated on a straight-line basis. The AER offsets changes in indexation of the RAB through its depreciation calculation and refers to this as 'regulatory depreciation'.
- Forecast operating expenditure and corporate income tax costs. We receive a revenue allowance to fund our operating activities and to meet our income tax liabilities.

[86] We note that while this proposal relates to the subsequent regulatory control period, the Rules require us to treat the 2014-15 transitional year as if it were the first year of the period. See clause 11.56.4.

- Other revenue increments or decrements. We receive a revenue increase or decrease based on outstanding penalties or rewards from incentive schemes that applied in the 2009-14 period. The Rules also enable a revenue decrement arising from the use of assets that provide standard control services to provide certain other services.

As part of the building block proposal we had also outlined our indicative prices for standard control services, and proposed our nominated pass through events, as required by the Rules.

In the sections below we set out our response to the AER's draft decisions on these matters. We note that the AER did not have to make a constituent decision on indicative prices, and for this reason we have not identified this in our revised proposal.

4.2. AER's draft decision

The AER rejected our proposed building block inputs including return on and return of capital, operating expenditure, corporate income tax and other revenue adjustments.

- Return on capital - The AER did not accept our proposed value for the opening asset base, forecast capex or allowed rate of return.
- Return of capital - While the AER accepted our methodology for determining the return of capital, it made consequential amendments to incorporate its decisions on opening asset base and forecast capex.
- Operating expenditure - The AER rejected our proposed operating expenditure.
- Cost of corporate income tax - The AER did not accept our proposed value for imputation credits, and made consequential amendments for its other decisions which impact the calculation of corporate income tax.
- Metering and Ancillary Network Services cost adjustment (for the 2014-15 year) – The AER did not accept our proposed metering and ancilliary network services cost adjustment for the 2014-15 year.
- Other revenue adjustments - The AER accepted our proposed shared asset reduction of zero.

Based on its decision on building block inputs, the AER rejected our proposed annual revenue requirements, X-factors and indicative prices. The AER also rejected our nominated pass through events. However it accepted our proposed method to roll forward the asset base using forecast depreciation.

4.3. Revisions to incorporate the AER's draft decision on building block inputs

We have revised our building block inputs to incorporate changes required by the AER in its draft decision:

- The return on capital is $21.7 million lower than our initial proposal. This reflects revisions to our allowed rate of return to reflect updates to market parameters and to incorporate changes required by the AER on the opening asset base, and changes to forecast capex.
- The return of capital is $2.1 million lower than our initial proposal. This relates to changes required to incorporate the AER's draft decision on indexation method and revisions to our forecast capex.
- The operating expenditure is $107.8 million higher than our initial proposal. The revisions we have made are set out in Chapter 6 of this proposal. Our revisions mainly relate to increases in our vegetation management costs, but also include the incorporation of progressive improvement in labour productivity over the regulatory period.
- The cost of corporate income tax is $15.4 million higher than our initial proposal. These are a consequence of changes made to the annual revenue requirement. Section 4.2 identifies why there has been a revision to the cost of corporate income tax.

- We have not revised our proposal for EBSS carry over amounts, but have incorporated the AER's decision on the demand management carry over amount. We note that the AER accepted our proposal on shared asset reduction, so no further revisions are necessary.

Table 4.4 provides our revised return on capital, return of capital, operating expenditure and cost of corporate tax. Our revised PTRM is at Attachment 4.01. This is further set out in the sections below:

Table 4.4: Annual revenue requirement building blocks (Unsmoothed)

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on capital	493.8	526.7	552.4	572.9	592.8	**2,738.6**
Return of capital	62.8	72.2	82.8	86.7	92.9	**397.4**
Operating expenditure	300.1	321.4	321.5	325.2	329.1	**1,597.2**
Cost of corporate tax	65.9	65.2	71.7	72.0	74.5	**349.2**
EBSS Adjustments	98.7	33.7	42.8	34.6	0.0	**209.8**
DMIS Revenue	0.6	0.6	0.6	0.7	0.7	**3.2**
Metering and ANS costs	62.5					**62.5**
DMIA carry-over		-3.0				**-3.0**
Total (Unsmoothed)	**1,084.4**	**1,016.8**	**1,071.8**	**1,092.1**	**1,090.0**	**5,355.0**

4.3.1 Return on capital

The AER rejected our return on and of capital based on its decision not to accept the opening value of the RAB, proposed forecast capex and proposed allowed rate of return.

We do not accept the AER's reasons for rejecting our proposed allowed rate of return and forecast capex and consequentially have not revised our proposed return on and of capital to reflect these decisions. We have provided a detailed response to the AER's draft decisions on forecast capex and allowed rate of return in Chapters 5 and 7 of this document.

In the sections below, we set out our comments on the AER's draft decision on the value of the opening asset base and depreciation schedules.

Value of opening asset base and method to roll forward asset base next period

The AER made a number of adjustments to our proposed value of the RAB as at 1 July 2014 (opening RAB values). We agree with these adjustments and have incorporated the opening RAB values in the calculation of our revised return on capital component of the annual revenue requirement. Additionally, we have sought to update our opening RAB values to reflect the 2013-14 actual expenditure which has now been audited and submitted to the AER as part of the Annual RIN process. The opening value for distribution standard control services and Type 5 and 6 metering services as at 1 July 2014 are set out in the table below:

Table 4.5: Opening Asset Base

$m; Nominal	Value as at 1 July 2014
Distribution standard control services	5,581.3
Type 5 and 6 metering services	18.8

Our revised roll forward models are set out in Attachment 4.02 of this revised proposal.

We also note that the AER made a draft decision on the depreciation method to roll forward the asset base at the end of the 2014-19 period. This does not impact revenues in the 2014-19 period but provides a capital expenditure incentive.

The AER decided to accept our proposal to apply forecast depreciation. We therefore have not revised our proposal in this respect.

Forecast capex

The AER did not accept Endeavour Energy's proposed forecast capex for 2014-19, and instead substituted an amount of $1,070.4 million ($m, Real 13-14). As outlined in Chapter 5 we considered the revisions necessary to incorporate the AER's draft decision on forecast capex for standard control services. Table 4.6 below sets out our revised forecast capex.

Table 4.6: Revised forecast capex

$m, Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Forecast capex	411.1	337.5	286.6	277.0	264.1	**1,576.3**

Allowed rate of return

The AER did not accept our proposed allowed rate of return, and the parameters for collecting this rate. As outlined in Chapter 7, we considered whether there were any revisions necessary to incorporate the AER's draft decision. We also considered whether any revisions were necessary to incorporate most current data.

Table 4.7: Proposed rate of return

Parameter	Initial proposal	Revised proposal
Overall rate of return	8.83%	8.85%
Cost of equity	10.11%	10.15%
Cost of debt	7.98%	7.98%
Gearing	60%	60%
Utilisation of imputation credits	25%	25%

4.3.2 Return of capital (Regulatory depreciation)

The AER did not accept Endeavour Energy's proposed regulatory allowance for return on capital mainly as a result of its decision to reject our proposed forecast capex and opening RAB. Nevertheless, the AER accepted other aspects of Endeavour Energy's calculation of regulatory depreciation namely proposed asset classes, the use of straight line depreciation method and standard lives.

We have revised our proposed regulatory allowance for return of capex based on revisions we have made to our initial proposal for forecast capex and opening value of asset base.

The calculation of regulatory depreciation is also dependent upon the remaining lives used to depreciate the opening RAB asset classes. Our initial proposal provisionally adopted the AER's preferred approach of calculating the remaining lives pending further investigation. Our initial proposal noted that the AER's preferred method over-estimates the remaining lives as new assets are given more weighting. We noted that our preliminary analysis showed that the AER's preferred approach to calculating remaining asset lives significantly over-weights new assets and therefore over-estimates the remaining life of assets on our network.

This is currently resulting in under-compensation for depreciation expense. Please see the report provided by Advisian at Attachment 4.03, that demonstrates the current roll-forward process has resulted in systematically higher remaining lives than is appropriate given the changing composition and generations of the underlying asset classes.

This higher estimated remaining life for regulatory purposes under-estimates actual depreciation expenses that are likely to be incurred by Endeavour Energy over the 2014-19 period. As noted in Chapter 1, we consider that this further exacerbates the financial sustainability of the AER's draft decision.

We engaged Advisian to review both standard and remaining asset lives. Advisian's report is at Attachment 4.03 and shows that the standard lives currently used in the calculation of the annual revenue requirement are not reflective of the economic life of the assets, however we plan to address this at a later time.

The Advisian report highlights that Endeavour Energy claims regulatory depreciation over a substantially longer period and will also recover our existing RAB over a much longer period than other DNSPs.

There is therefore a case to reduce the standard lives used, which increases the value of revenue recovered due to a higher depreciation charge, which is only partially offset by a lower return on capital.

Shortening the standard and remaining asset lives assumptions would enable the businesses to:

- Address the inconsistency between the technical lives reported in the annual RINs and the standard lives used for regulatory depreciation;
- Align the standard lives with the lives used by other DNSPs; and
- Protect against network bypass. Technology changes and reducing costs of off-grid supply options have the potential to create genuine competition for network business. This competition may have the effect of constraining the maximum prices that may be charged by network businesses, and therefore the capacity for cost recovery. Increasing the rate of depreciation in the period while the direct competition for network services is low and the price elasticity of demand similarly is low, as opposed to increasing prices if (or once) direct competition for network services emerges, may help guard against the risk of not being able to recover costs in future.

In order to recover past efficient investment over a reasonable timeframe that minimises the risk of network bypass as noted above, while at the same time constraining average distribution network charges to the rate of change of inflation requires a shortening of the standard and remaining lives assumptions over time. Therefore, Endeavour Energy has not shortened its standard and remaining lives in this revised proposal, but notes its intention to move in this direction in subsequent regulatory determinations.

Clause 6.5.5(b)(1) of the Rules requires depreciation schedules to conform to a number of requirements, one of which is that 'the schedule must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets'.

While we have not revised our standard or remaining lives in this revised proposal, we have provided our initial analysis on this matter in anticipation of updating these lives at the subsequent (i.e. 2019-24) determination. Attachment 4.03 outlines the rationale and quantum associated with a change to future standard and remaining lives to address, amongst other things, the impact of technological change and the ability to recover efficient costs in future.

4.3.3 Operating and tax costs

The AER rejected our proposed forecast opex and cost of corporate income tax for the 2014-19 period. We do not accept the AER's draft decision. Our detailed response to the AER's draft decision is set out in Chapter 6 of this document. As set out in section 4.4, we have also made revisions to our proposed opex.

Forecast opex

The AER did not accept Endeavour Energy's proposed forecast opex for 2014-19, and instead substituted an amount of $1,070.9 million. As outlined in Chapter 6 we considered the revisions necessary to incorporate the AER's draft decision on forecast opex for standard control services. Table 4.8 below sets out the revised forecast opex:

Table 4.8: Revised forecast opex (inc. DMIS and DRC)

$m, Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Forecast opex (inc. DMIS and DRC)	289.8	302.7	295.5	291.6	287.9	**1,467.4**

Corporate income tax

The AER also rejected our proposed cost of corporate income tax. This was mainly due to the AER's draft decision to reject Endeavour Energy's proposed opening value of the tax asset base and proposed value of imputation credit.

On the imputation credit input into the calculation of corporate tax, our initial proposal proposed a value of 0.25. The AER rejected this value and substituted for a value of 0.40. We do not accept the AER's draft decision on the value of imputation credit and consequently have not revised our estimate of corporate tax to incorporate the AER's draft decision. Chapter 7 of our proposal sets out our detailed reasons why we consider the AER should have accepted our proposed value of imputation credits of 0.25.

The AER's substituted estimate of corporate income tax was also the consequence of the AER's draft decision on other areas of the building block proposal such as forecast capex and allowed rate of return. Our responses to these other decisions are detailed in other parts of this revised proposal. Endeavour Energy's revised estimate of corporate income tax is reflective of our revisions to other elements of the building block approach and is shown in Table 4.9.

Table 4.9: Cost of Corporate Income Tax

$m, Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Cost of corporate income tax	65.9	65.2	71.7	72.0	74.5	**349.2**

4.3.4 Shared asset reduction and DM carry over amount

The Rules require that the AER allow Endeavour Energy to include revenue increments or decrements that relate to the operation of incentives from the 2009-14 period. The Rules also enable a DNSP to propose a revenue decrement for shared assets arising from the use of assets that provide standard control services to provide certain other services.

The AER has accepted our proposal that there should not be a revenue decrement for shared assets. We have reviewed the AER's draft decision to see if the materiality threshold is impacted by revisions we have made to our annual revenue. Our calculation is set out below. Based on this calculation we have not revised our proposal.

Table 4.10: Materiality of Shared Asset Revenue

$m, Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Forecast unregulated revenue from shared asset	5.53	6.01	6.01	6.28	6.54	**30.4**
Smoothed revenue (prior to shared asset reduction)	949.5	1,058.6	1,092.2	1,123.5	1,167.1	**5,390.8**
Materiality percentage	**0.58%**	**0.57%**	**0.55%**	**0.56%**	**0.56%**	**0.56%**

D-factor lag

The AER has also accepted our proposed method to include the lagged carry over amount for the operation of the DMIS as part of changes to annual prices.[87]

4.3.5 EBSS carry over amount from operation of scheme in 2009-14

The AER however, has not accepted Endeavour Energy's calculation of the revenue increment from the application of the EBSS in the 2009-14 period. The AER rejected Endeavour Energy's calculation because:

> *"It is not satisfied Endeavour Energy's proposed EBSS carryover amounts comply with the requirements in the EBSS Endeavour Energy operated under during the 2009-14 regulatory control period. The difference between our calculations of the EBSS carryover amounts and Endeavour Energy's proposal is due to the treatment of expenditure recorded as provision."*[88]

On this basis, the AER substituted Endeavour Energy calculated carryover amount with its own calculated amount of $93.4 million. We do not accept the AER's draft decision for the following reasons:

- It was not calculated in accordance with the EBSS scheme that the AER determined should apply to Endeavour Energy for the 2009-14 period.
- The AER's contention that provisions are not costs and hence should be excluded from the calculation. In our view changes in employee related provisions do represent actual costs incurred by Endeavour Energy.

[87] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Attachment 12 November 2014, p9.

[88] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Attachment 9, November 2014, p7

- Assuming the AER's contention that provisions are not costs and therefore should be excluded (a point that we do not agree with), the AER has made an error in its calculation by excluding this amount from the actual opex only and not the forecast opex.

Consequently, we have not incorporated the AER's substituted amount in our revised annual revenue requirement.

Compliance with the AER's determined scheme

The AER decided to apply the EBSS released in February 2008 (2008 EBSS) to Endeavour Energy for the 2009-14 period with the resulting financial results from the application of this scheme having effect in the subsequent period (i.e. 2014-19). The applicable EBSS allowed for the exclusion of certain opex categories from the application of the scheme.

In deciding how the 2008 EBSS should apply to Endeavour Energy, the AER decided to exclude debt raising cost, self-insurance costs, insurance costs, superannuation costs relating to defined benefits and retirement schemes and non-network alternative costs from the operation of the EBSS. That is, these costs were excluded from the total forecast the AER determined for Endeavour Energy when applying the 2008 EBSS.

Specifically the AER determined a total opex allowance for Endeavour Energy of $1,516.5 million ($2008-09) from which the AER excluded $61.9 million ($2008-09) to arrive at a total forecast opex of $1,454.6 million ($2008-09) as the total forecast opex for the purpose of applying the EBSS and particularly for the purpose of calculating the efficiency gains/losses to be carried over to the 2014-19 period. In its decision, the AER unequivocally stated that:

> *"In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the EBSS to apply to the NSW DNSPs is as specified in this section 13.6."*[89]

Nowhere in its final determination or its 2008 EBSS did the AER specified that 'movement in provisions' is to be excluded from the calculation of the carryover amount.

Throughout the 2009-14 period, Endeavour Energy submitted the actual opex to be used in applying the 2008 EBSS to the AER in the annual regulatory accounts (or RIN). The format of this RIN is specified by the AER and in relation to the information on EBSS opex, the AER required Endeavour Energy to report the actual opex incurred for each of the cost categories the AER excluded from the operation of the EBSS in its final determination for Endeavour Energy. Endeavour Energy complied with this request and clearly identified the actual opex for each year of the 2009-14 period that were to be subject to the operation of the EBSS.

We used these actual opex amounts in our calculation of the carryover amount we proposed in our initial proposal . We consider that we have applied the scheme correctly and have complied with the AER's final determination for 2009-14 as to how the scheme is to be applied and the carryover amount is to be calculated. Further, the 2008 EBSS states:

> *"In calculating the benefits or losses to be carried over, the measurement of actual expenditure over the regulatory control period must be done using the same cost categories and methodology used to calculate the forecast expenditure for that period. Adjustments will be made where necessary to correct for variances in cost categories and methodologies, and errors."*[90]

There are no adjustments necessary to correct for variances in cost categories and methodologies and errors. The AER's draft decision to exclude movements in provisions contravenes its 2009-14 determination and applicable guideline. The decision is tantamount to a retrospective change and application of the scheme.

[89] AER, Final decision – NSW Distribution Determination 2009-10 to 2013-14, April 2009, p250.

[90] AER, Efficiency Benefit Sharing Scheme for the ACT and NSW 2009 Distribution Determination, February 2008, p5.

Movement in provisions

The AER contended that movements in provisions should be excluded from the EBSS calculations. This is because the increases in provisions do not represent the actual cost incurred in delivering network services when calculating efficiency gains or losses.

We consider that increases in provisions are cost incurred in the provision of standard control services. The fact that it is set aside and to be paid in the future does not change its nature of being a cost incurred in the providing the services.

In order to provide standard control services, Endeavour Energy must employ resources (i.e. employees) and have systems and processes in place to provide this service (e.g. IT systems etc.). At times and where appropriate and efficient to do so, we also employ contracted services. A person, employed by Endeavour Energy is entitled to receive a salary and other entitlements which are annual leave, sick leave, superannuation and long service leave. To Endeavour Energy, the total cost of employing this person is the total cost of that person's salary and the costs of his/her entitlements. From a different perspective, this is the costs that Endeavour Energy must bear in order to provide standard control services to customers, for example, maintain the network etc.

The timing of cash outlay to satisfy these salaries and entitlements that Endeavour Energy's employees are entitled to does not of itself change the nature of the cost or the purpose for which it is being incurred. The employment of a technician (for example) is necessary in order to provide network services; and the cost of employing that technician comprises of salary payments and leave entitlements. Endeavour Energy has 'consumed' the service provided by that person at the time the person provided the service (e.g. fix damage on the network) and the total cost to Endeavour Energy of 'consuming' that service is the salary, leave costs and other entitlements.

The fact that the salary component of the cost is paid almost simultaneously with the consumption of the service and the leave entitlement is paid when that person takes leave does not magically alter the nature of the costs. Instead of paying cash immediately, provisions are simply the setting aside of the portion of the total costs that Endeavour Energy has incurred in providing network services and those provisions are called upon when the person takes leave, which could be many months after the time that the services for which the costs were incurred was performed. It is a fallacy to assert that movements in provisions are not actual cost incurred in delivering network services.

Consider the alternative of Endeavour Energy employing a contractor to perform the same tasks that an employee would need to do, Endeavour Energy's cash payment to the contractor would be inclusive of the salary equivalent and the leave entitlement equivalent that Endeavour Energy would need to pay to the employee.

By endorsing this approach, the AER can be said to be acknowledging that the costs that the AER incurs in performing its functions comprise only of the cash salary it pays to its employees and nothing else. The costs relating to its employees entitlements are not actual costs required by it to perform its functions and provide its services and therefore no funding should be given for these costs (which would, similar to Endeavour Energy's, be reflected in provisions in the AER's own financial accounts).

Endeavour Energy has engaged Ernst & Young (EY) to in relation to the AER's approach towards movements in provisions in the draft determination. The EY report is provided as Attachment 4.04.

Consistency with forecast opex

The AER also asserted that its draft decision to exclude movements in provisions is consistent with the 2008 EBSS because the 2008 EBSS stated that:

> *"In calculating carryover gains or losses, the AER must be satisfied that the actual and forecast opex accurately reflects the costs faced by the DNSP in the regulatory control period."*[91]

The AER contended that the movements in provisions are not actual costs incurred in delivering network services. The AER however, have ignored the forecast opex in its calculation. As stated above, the AER's final determination for Endeavour Energy for the 2009-14 period decided that a number of cost categories be excluded and set a forecast opex for the purpose of the EBSS with these costs excluded. Movements in provisions were not one of the exclusions.

Now the AER has retrospectively changed the operation of the scheme by excluding movements in provisions from actual costs as it contended that movements in provisions are not actual costs. To be consistent with its own guidelines, the AER must also adjust the forecast opex for this change in approach.

Retrospective adjustments to incentive mechanisms

Notwithstanding our concerns with the AER's ability to set aside the 2009-14 determination and to redefine the exclusions to the carry forward, perhaps a more significant issue is the impact on incentives arising from the AER's retrospective adjustment to the EBSS as it applies to Endeavour Energy.

We are not aware of any rule that explicitly provides discretion for the AER to retrospectively introduce additional excluded cost categories for the EBSS or to revise/review adjustments, and there are strong arguments that the AER is not entitled to do so.

The NER provides an incentive based regulatory regime for DNSPs. This is reflected in the mandatory requirement for the AER to develop an "incentive scheme or schemes… that provide for a fair sharing between Distribution Network Service Providers and Distribution Network Users…" of efficiency gains and losses under clause 6.5.8(a) of the NER. The focus on incentives is further emphasised by the factors that the AER must have regard to when developing and implementing the EBSS in clause 6.5.8(c) of the NER, which include:

> *"(1) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers;*
>
> *(2) the need to provide Distribution Network Service Providers with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure;*
>
> *(3) the desirability of both rewarding Distribution Network Service Providers for efficiency gains and penalising Distribution Network Service Providers for efficiency losses;*
>
> *(4) any incentives that Distribution Network Service Providers may have to capitalise expenditure; and*
>
> *(5) the possible effects of the scheme on incentives for the implementation of non-network alternatives."*

A DNSP cannot be incentivised by retrospective changes to a scheme because the actions that are sought to be incentivised or dis-incentivised have already occurred. Incentives are created by the promise of rewards or penalties. Retrospective changes to either the excluded cost categories or revisions of adjustments made by the DNSPs may instead dis-incentivise DNSPs going forward because there is a risk that the EBSS (or any other regulatory decision) as it is applied to the NSW DNSPs in the future may be different to how the AER represented that the EBSS would apply when it was introduced.

[91] AER, Efficiency Benefit Sharing Scheme for the ACT and NSW 2009 Distribution Determination, February 2008, p6

If the EBSS is not applied by the AER in a manner consistent with its previous representation that provisions were not an excluded cost category, then there is a risk that DNSPs will not believe that the AER has the regulatory commitment to keep other regulatory promises. Equally, if revisions of adjustments are made at the end of a regulatory control period, then DNSPs may consider that there is a risk that the AER would review/revise other efficiency gains or losses made. Both of these factors jeopardise the incentive features of the EBSS.

For the above reasons, Endeavour Energy has not revised its proposal to incorporate the AER's draft decision or reasons for that decision. Table 4.11 shows the EBSS revenue from the correct application of the AER's approved scheme.

Table 4.11: Proposed EBSS Carry Over Amount

$m, Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
EBSS carry over amount	95.1	31.7	39.2	31.0	0.0	**197.0**

4.4. Revisions to incorporate AER's draft decision on revenue and X-factors

In our initial proposal, we used the sum of the building blocks to derive Endeavour Energy's unsmoothed total proposed annual revenue requirement. We also proposed the adjustment to the annual revenue requirement for the transitional year, and our smoothed revenue and X-factors. We also set out our proposed transitional year adjustment and method. Our proposal also provided indicative prices.

4.4.1 Proposed revenue requirements and X-factors

The AER's draft decision on the unsmoothed annual revenue requirements, smoothed revenue and X-factors were based on decisions on other elements of the building blocks. As noted in section 4.1 to 4.3 we have made revisions in our building blocks to respond to some of the matters raised by the AER in its draft decision.

Table 4.12 and 4.13 sets out our revised unsmoothed revenue, and our smoothed revenue and resultant X – factors.

Table 4.12: Indicative annual and smoothed revenue requirements

$m, Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Unsmoothed revenue	**1,084.4**	**1,016.8**	**1,071.8**	**1,092.1**	**1,090.0**	**5,355.0**
Smoothed revenue	949.5	1,058.6	1,092.2	1,123.5	1,167.1	**5,390.8**

We have made the following revisions to our initial proposal:

- Our unsmoothed revenue is 1.9% higher than the initial proposal . This largely reflects the consequential amendments we have made as a result of revisions to our building block components in particular the requirement for additional vegetation costs to manage bushfire, public safety and reliability risk.
- The changes to the smoothed revenue reflect consequential amendments to incorporate the revisions to unsmoothed revenue. It also reflects the revisions we have made to ensure we recover the shortfall of revenues under the AER's transitional determination for the 2014-15 year. In this respect we note that we need to recover $134.9 million (revised unsmoothed revenue less the AER's transitional decision for 2014-15). We have used the same smoothing methodology as our initial proposal.

We have also made consequential amendments to the X-factors as a result of changes to the smoothed revenue and to reflect the AER's transitional decision and associated adjustments over the remaining years of the period to account for our proposed 2014-15 revenue. This is set out below.

Table 4.13: X-factors used to smooth revenues (% change in real revenues), excluding inflation

%; Real	2014-15	2015-16	2016-17	2017-18	2018-19
Distribution X-factors	8.74%	-8.78%	-0.65%	-0.36%	-1.35%

Note: A positive revenue X-factor denotes a real revenue reduction.

4.4.2 Transitional year adjustment

The changes evident in the table above largely reflect the AER's draft decision to provide a revenue allowance significantly below what we proposed for the 2014-15 transitional year. This meant that prices for 2014-15 were 'locked in', meaning that the shortfall in revenue must be recovered in the remaining four years.

In its decision, the AER's transitional year adjustments was based on a value that reflects its decisions on the unsmoothed revenue amount for 2014-15. In the section above, we noted that we revised our proposal but the value is different from the AER's draft decision.

We consider that our revised unsmoothed revenue should be used as a value for the transitional year adjustment in the AER's final decision. As a consequence, a $134.9 million positive adjustment is required over the remaining four years of the period. This compares to the $103.4 million negative adjustment the AER included in its draft decision which it calculated by comparing the transitional determination to its draft decision.

4.4.3 Indicative Prices

In this section we have sought to demonstrate how our revisions have impacted prices. In response to customer feedback and to comply with the NEO and relevant NER provisions, we sought to minimise pricing volatility. Our revised expenditure plans and Weighted Average Cost of Capital (WACC) enabled us to deliver on our promise to keep our contribution to pricing increases at or below CPI for the 2014-19 period on average. Our revised proposal forecasts a real reduction to average network charges of 0.5% by the end of the 2014-19 period for customers, which results in a level that is sustainable and avoids future price shocks.

Our initial proposal was based on our forecast revenue requirements over the full 2014-19 period. We consider this was consistent with the intent of the transitional arrangements. Furthermore, we considered it would be more appropriate and realistic to deal with the true up of the transitional year decision in the revised proposal or the AER's final decision.

However, in its draft decision the AER has misrepresented our initial proposal by adjusting it for their transitional decision. This is not appropriate as this was not our proposal as we do not accept the AER's transitional decision which set a revenue allowance utilising a different WACC than that proposed by Endeavour Energy. Specifically the AER stated:

> *"If the lower distribution charges from our draft decision are passed through to consumers, we would expect the annual electricity bill for a typical residential customer to reduce on average by $159 in 2015–16, all else being equal. This compares with a typical bill increasing on average by $86 in 2015–16 under Endeavour Energy's proposal."*[92]

[92] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Overview, November 2014, p9

This was categorically not our proposal as we do not accept the AER's transitional decision and our proposal covered the 2014-15 to 2018-19 period and not just the 2015-16 year. As noted in section 4.4.2, we consider the transitional decision should be incorporated into the revenue smoothing for the purpose of giving effect to the true up mechanism only.

Whilst the revisions to our expenditure plans and proposed WACC have had an impact on our indicative prices, we have managed to contain our contribution to pricing increases at or below CPI for the 2014-19 period on average.

We consider our revised proposal does not differ greatly to our initial proposal as it adheres to our pricing commitment. The revised price path provides smooth, stable price reductions to customers whilst minimising the final year pricing difference.

In contrast, the AER has prioritised short term price reductions in preference to the sustainable, stable price path proposed by Endeavour Energy. Specifically, the AER's draft decision provides for the full impact of its decision in the 2015-16 year with minimal revenue X-factors in the remaining three years. This exacerbates the volume risk the AER has shifted to customers by moving Endeavour Energy to a revenue cap. Under the AER's draft decision there is no room available in the X-factors for Endeavour Energy to mitigate or manage the impact of volume variance.

We consider the AER's transitional and draft decisions have not sought to minimise price variations for customers. The variation evident in the AER's draft decision above is contrary to the intent of the AEMC that was outlined in its development of the Transitional Rules associated with the September 2012 Rule changes:

> *"During the consultation process it became apparent that there was a fifth principle that the Commission should have regard to when developing transitional arrangements. That is, any arrangements put in place to facilitate the transition to the new rules should minimise the potential for one-off price shocks."*[93]

and

> *"It is worth noting in this context that the AER is already required by section 16 of the NEL to have regard to both the NEO and the RPP when performing an economic regulatory function. The only additional criterion that the transitional rules require the AER to have regard to is therefore the "reasonably likely to minimise price variations" criterion. This criterion has been incorporated in the transitional rules to minimise the potential for the placeholder determination to result in one off price shocks."*[94]

In its final decision, we consider the AER should revise its approach in the draft decision to provide greater stability to customers and smooth prices over the full regulatory period. This will be particularly important in giving effect to the true up mechanism to adjust the transitional year decision as noted in section 4.4.2.

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[93] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p 216

[94] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p 238

4.5. Pass-through events

The pass-through mechanism in the NER recognises that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass-through allows a business to seek the AER's approval to recover (or pass through) the costs of a defined, unpredictable, high-cost event. In our initial proposal we nominated four pass through events including insurance cap event; natural disaster event; terrorism event and insurer's credit risk event.

This section responds to the AER's draft decision on nominated pass through events as detailed in Attachment 15 of the AER's draft determination.

The AER accepted insurance cap event, natural disaster event, terrorism event as nominated pass through event for the 2015-19 period with modifications to Endeavour Energy's proposed definitions of these events. The AER however rejected insurer's credit risk event as a nominated pass through event.

4.5.1 Revised proposal

Endeavour Energy's revised proposal:

- Accepts the AER's draft decision that insurance cap event, natural disaster event and terrorism events are nominated pass through events.
- Does not agree with the AER's draft decision that a insurer's credit risk event is not a pass through event; consequentially we have maintained our nomination that this event should be a pass through event.
- Revised our proposed definitions of these events in light of the AER's draft decision to provide clarity and distinction between the defining of these events and the assessment criteria which should not be part of the definition of a pass through event.

Endeavour Energy submitted Attachments 4.10 and 6.13 in support of its initial proposal on nominated pass through events. These attachments remain our regulatory proposal on pass through events save for the definitions of pass through events replaced by those outlined below.

4.5.2 Response to AER's draft decision

Insurer's credit risk event

The AER did not accept an insurer's credit risk event because it considered a prudent service provider could reasonably prevent an event of that nature from occurring. This is on the basis of part c of the nominated pass through event considerations which is:

> *"Whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event."*[95]

The AER consider that a prudent service provider would use an insurance provider that has the capacity to satisfy any claims under a policy. The AER claims that NSPs can assess the viability of an insurer by reviewing its track record, size, credit rating and reputation. The AER claims that the inclusion of this event removes the incentive for Endeavour Energy to obtain insurance from a reputable provider who is able to pay a claim. The AER considers that Endeavour Energy is able to take steps to mitigate or prevent this event from occurring.

[95] NER, Chapter 10 Glossary – Definition of Nominated Pass Through Event.

We do not concur with the AER's draft decision and reasons. We consider the AER has made an error of fact in that it has not demonstrated an understanding or interpretation of the material we provided. It is not obvious that the AER, in reaching its decision to not approve the insurer's credit risk event, has considered all the material put before it by Endeavour Energy. For example, the AER by making a statement that 'NSPs can assess the viability of an insurer by reviewing its track record, size, credit rating and reputation' it fails to demonstrate that it has considered our risk management methodology or that it reviewed the external Ernst & Young's regulatory treatment of risk report (Attachment 6.13 of Endeavour Energy's initial proposal).

This material highlights how Endeavour Energy's insurance arrangements encompass a robust and thorough renewal and review process; and the nominated pass through events (including the insurer's credit risk event) proposed by Endeavour Energy are appropriate because they capture the risks which are beyond the control of Endeavour Energy to prevent or mitigate.

In particular, Endeavour Energy seeks to mitigate the risk of any of insurers becoming non-viable by regularly monitoring and reporting by its broker of insurer Standard & Poor's (S&P) rating movements. Our minimum acceptable insurer S & P rating is A-. We also keep liability insurance exposure to A- insurers to less than 7.5% and our brokers Aon and Marsh monitor insurer ratings to ensure that any changes are flagged as soon as possible. Our brokers cannot and do not guarantee the security of our insurers.

An excerpt of the Ernst & Young report is provided below. This excerpt demonstrates the prudent risk management framework in place at Endeavour Energy.

"Under the NSW DNSPs' risk management framework:

- *The framework uses a Bow-Tie methodology to identify and assess any relevant risks and to understand the nature of these risks (e.g. likelihood, impacts)*
- *The framework identifies and implements risk controls which are either preventative controls (to lower the chance of the hazardous event happening) or mitigation controls (to lessen the consequences if it does)*
- *The NSW DNSPs maintain comprehensive insurance arrangements, which are regularly reviewed to align with the Bow-Tie risk assessments. In addition:*
  - *The insurance arrangements encompass a robust and thorough renewal and review process including forward strategic planning and gathering of updated risk information (including Bow-Tie updates) in order to "sell" their risks appropriately to the global insurance market*
  - *Advice is obtained from external risk and insurance brokers/consultants (currently Aon and Marsh) and the DNSPs' own insurance specialists to establish the appropriate levels of coverage, implement appropriate insurance market negotiation strategies and to efficiently and effectively manage any claims. The insurance market is cyclical and subject to change, therefore the appropriate levels and types of coverage can vary each year in order to obtain insurance coverage on optimal terms from the market to align with risk treatment strategies.*
  - *The NSW DNSPs take a coordinated approach to insurance with a Group Insurance Committee (GIC) overseeing the insurance renewal and review process. GIC membership is made up of senior group executives and senior executives from each network business, including the Group CFO, Group Executive Network Strategy, Board Secretary, General Managers Finance and Compliance and insurance specialists."*[96]

[96] Ernst and Young, Review of regulatory treatment of risk (Attachment 6.13 of Endeavour Energy's substantive proposal), April 2014, p9.

Moreover, the AER's contention that DNSPs will always be able to assess the viability of an insurer does not take into account how severely impacted the NSW DNSPs were by the unforseen collapse of HIH – Australia's second largest insurer at the time and the largest corporate failure in Australia's history. We submit that even the most prudent risk management approach could not mitigate against such an occurrence, making a pass through a necessary risk management approach to cover such events.

We consider that our approach to nominating this pass through event is reasonable and based on sound reasoning and satisfied the nominated pass through event considerations of the Rules. Endeavour Energy could neither do anything further to prevent an insurer's credit risk event from occurring nor could Endeavour Energy substantially mitigate the cost impact of such an event.

We also note that the AER's draft decision is inconsistent with its previous approaches or decisions. Notably, the AER has approved a similar pass through event in several of its determinations including the Victorian DNSPs and Aurora.[97]

Accordingly, the AER should approve the insurer's credit risk event as a nominated pass through event having regard to the considerations and evidence described above.

For the reasons above, we have not incorporated the AER's draft decision on this event in our revised proposal. Our revised proposal maintains this event as a nominated pass through event; with the definition of the event described below.

Definitions

The AER's draft determination accepted our nomination of insurance cap event, terrorism event and natural disaster event as pass through events. As noted above we accept this draft decision.

In accepting these events as pass through events, the AER however has amended the definitions of these events as we proposed in the initial proposal. The AER amended the definitions to include within these definitions the factors that the AER will have regard to when assessing a claim for pass through.

We note our proposed definitions of insurance cap event and natural disaster event in the initial proposal also included factors for assessing these pass through events. We adopted these definitions simply to be consistent with the AER's definitions for these events approved in its previous determinations.

The AER's draft determination decided to include assessment factors for the definition of pass through events. We have given further consideration to the inclusion of assessment factors within the relevant definitions and on further reflection we do not agree that these assessment factors should be included in the definitions. This is because these factors are not actually relevant to defining events but rather are relevant to other aspects of the AER's assessment of pass through events at the time of its occurrence. These aspects relate to (a) the AER's assessment of the approved pass through amounts under 6.6.1(d) or 6.6.1(g) and (b) the nominated pass through events considerations. We note that the nominated pass through events considerations are only relevant as criteria for the AER's decision on whether to accept Endeavour Energy's nominated events as pass through events.

The occurrence of an approved nominated pass through event itself does not automatically mean that the DNSP can pass through the costs to customers. The DNSP must demonstrate, and the AER must determine, that:

A positive change event has occurred – that is the pass through event has resulted in material increase in costs.

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[97] AER, *Victorian electricity distribution network service providers distribution determination 2011-2015, Final Decision,* October 2010; AER, *Final Distribution Determination; AER, Aurora Energy Pty Ltd 2012-13 to 2016-17,* 30 April 2012.

If the AER is satisfied that a positive change event has occurred, the approved pass through amounts, based on the factors in clause 6.6.1(j) of the Rules.

Inclusion of the factors in the definition of the event is also inconsistent with four pre-defined pass through events under the Rules. Chapter 10 of the Rules defines these four events (regulatory change event, service standard event, tax change event and retailer insolvency event) and none of the definitions include assessment factors. For all of these reasons Endeavour Energy submits that assessment factors should be excluded from the definitions and we have revised our proposed definitions accordingly. Our more detailed analysis of the AER's proposed definitions and our reasoning and justification in relation to the individual definitions is set out below.

For insurance cap event:

> *"Note for the avoidance of doubt, in assessing insurance cap event cost pass through application under rule 6.6.1(j), the AER will have regard to:*
>
> i. *The insurance policy for the event; and*
>
> ii. *The level of insurance that an efficient and prudent NSP would obtain in respect of the event*
>
> iii. *The extent to which a prudent provider could reasonably mitigate the impact of the event."*[98]

For natural disaster event:

> *"Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:*
>
> *Whether Endeavour Energy has insurance against the event:*
>
> i. *The level of insurance that an efficient and prudent NSP would obtain in respect of the event.*
>
> ii. *Whether a relevant government authority has made a declaration that a natural disaster has occurred; and*
>
> iii. *The extent to which a prudent NSP could reasonably mitigate the impact of the event."*[99]

For terrorism event

> *"In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:*
>
> *Whether Endeavour Energy has insurance against the event:*
>
> i. *The level of insurance that an efficient and prudent NSP would obtain in respect of the event.*
>
> ii. *Whether a declaration has been made by a relevant government authority that a terrorism event has occurred*
>
> iii. *The extent to which a prudent NSP could reasonably mitigate the impact of the event."*[100]

[98] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Attachment 15, November 2014, p14

[99] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Attachment 15, November 2014, p15

We consider these parts of the definitions are unnecessary as they do not define the events themselves but rather they are factors that go to the assessment of the cost impact of the event or the assessment of whether the event proposed by the NSP should be accepted by the AER as pass through events in its determination. These parts of the AER's amended definitions are already covered in various provisions of the Rules dealing with assessment of the costs to be pass through or the acceptance of the event as pass through event.

- Under clause 6.6.1(c)(6) of the Rules, an NSP must include in its pass through application evidence of (a) the actual and likely increase in costs and (b) that such costs occur solely as a consequence of a positive change event. Satisfying these requirements would require the NSP to provide details of the insurance policies and the level of insurance.
- Clause 6.6.1(j)(3), (5) and (7) respectively state that:
    - *"(3) In case of a positive change event, the efficiency of the DNSP's decisions and actions in relation to the risk of the positive change event, including whether the DNSP has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the DNSP has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event.*
    - *(5) the need to ensure that the DNSP only recovers any actual or likely increment in costs under this paragraph (j) to the extent that such increment is solely as a consequence of a pass through event.*
    - *(7) whether the costs of the pass through event have already been factored into the calculation of the DNSP's annual revenue requirement for the regulatory control period in which the pass through event occurred or will be factored into the calculation of the DNSP's annual revenue requirement for a subsequent regulatory control period."*[101]

In making a determination on the approved pass through amounts, the AER must take into account the above provisions (and others specified under 6.6.1(j)). This exercise would entail the consideration of:

- the insurance policy for the event;
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and
- the extent to which a prudent provider could reasonably mitigate the impact of the event.

In addition, the nominated pass through event considerations in the Rules also require, inter alia, the following consideration in whether the AER approve the events nominated by a DNSP as a pass through event:

> *"(c) whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event."*[102]

For the above reasons, Endeavour Energy considers it unnecessary to include these parts of the AER's definition in either the definition of insurance cap event, natural disaster event and terrorism event or as factors in the assessment of a pass through application. This is simply because these matters are neither needed to define the events nor needed as assessment factors as they have already been covered in the relevant provision of the Rules.

The AER also amended Endeavour Energy's proposed definition of natural disaster event to include a caveat

> *"Provided the fire, flood or other even was not a consequence of the acts or omissions of the service provider"*[103]

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[100] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Attachment 15, November 2014, p15

[101] NER, Clause 6.6.1(j)(3), (5) and (7).

[102] NER, Chapter 10 Glossary – Definition of Nominated Pass Through Event.

[103] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 - Attachment 15, November 2014, p15

We consider that this caveat is not necessary in defining the event. This caveat goes to the assessment of the approved pass through amounts and is encapsulated within the Rules provision 6.6.1(j)(3). This is a factor the AER must take into account in determining the approved pass through amounts. It may well be the case that the approved pass through amount proposed by a NSP is significantly reduced because of its acts or omission.

This fact however does not mean that a natural disaster event has not occurred (a definition issue). Moreover, the caveat is a departure from previous AER's determinations and we consider that are no sound basis for such departure.

The AER has also added to the definition of natural disaster event an element which is 'whether a relevant government authority has made a declaration that a natural disaster event has occurred.' We do not support this additional element as it does not enhance or further clarify the definitional boundaries of a 'natural disaster event'. A major fire could occur within Endeavour Energy's network area that materially increases the costs to Endeavour Energy of providing direct control services and yet it may not be declared by a relevant government authority as a natural disaster event. Endeavour Energy has no control or influence over the decision to be made by a relevant government authority and considers that we should not be limited in our ability to pass through the costs of a natural disaster event simply because it has not been declared as a natural disaster event by a relevant government authority (despite all other elements for the pass through of costs under the Rules have been satisfied).

For similar reasons, we do not concur with the inclusion of the additional element 'whether a declaration has been made by a relevant government authority that a terrorism event has occurred'. The reference to a relevant government authority is too vague and may lead to unintended exclusion of events which are in fact terrorism event under the definition. It is not clear what may be regarded as 'relevant'. Some legislative provisions maybe directed at triggering insurance caps or other types of relief and are not concerned with whether there has been a terrorism event as such but a certain type of event or an event with certain insurance consequences.

Revised definitions

Following are Endeavour Energy's revised definitions for insurance cap event, terrorism event, natural disaster event and insurer's credit risk event. For avoidance of doubt, we accept the AER's draft decision that insurance cap event, terrorism event and natural disaster event are pass through events for the 2015-19 regulatory period.

We have only revised the definitions of these events in response to the AER's draft decision and reasons. In relation to insurer's credit risk event, we have not accepted the AER's draft decision to reject this event as a pass through event. Our revised proposal includes this event as a nominated pass through event.

Insurance cap

An insurance cap event occurs if:

> *"Endeavour Energy makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,*
>
> *Endeavour Energy incurs costs beyond the relevant policy limit, and*
>
> *The costs beyond the relevant policy limit materially increase the costs to Endeavour Energy in providing direct control services."*

For this insurance cap event:

> *"The relevant policy limit is the greater of:*
>
> - *Endeavour Energy's actual policy limit at the time of the event that gives, or would have given rise to a claim, and*

- *the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.*

A relevant insurance policy is an insurance policy held during the 2015-19 regulatory control period or a previous regulatory control period in which Endeavour Energy was regulated."

Natural disaster

A natural disaster event is defined as:

"Any major fire, flood, earthquake or other natural disaster beyond the reasonable control of Endeavour Energy that occurs during the 2015-19 regulatory control period and materially increases the costs to Endeavour Energy in providing direct control services.

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the DNSP's annual revenue requirement for that regulatory year)."

Terrorism event

A terrorism event is defined as:

"an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to Endeavour Energy in providing direct control services."

Insurer credit risk event

For completeness, we also include below the definition of insurer's credit risk event we consider the AER should accept in its final decision (both in terms of the event being a nominated pass through event and the corresponding definition).

"The insolvency of a nominated insurer of Endeavour Energy, as a result of which Endeavour Energy:

i. incurs materially higher or lower costs for insurance premiums than those allowed for in its Distribution Determination; or

ii. in respect of a claim for a risk that would have been insured by Endeavour Energy's insurer's, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy."

Application to alternative control services

Our initial proposal also considered that the pass through provisions of the Rules to apply to alternative control services. Our reasons in support of this proposal were outlined in section 9 of Attachment 4.10. We noted that our proposed application of pass through provisions is consistent with previous determinations by the AER. The AER's draft decision appears silent on this aspect of our proposal. We ask that the AER makes a decision consistent with our proposal and its determinations for other network service providers in its final determination for Endeavour Energy.

5 CAPITAL EXPENDITURE

Summary

We have considered the AER's draft decision and have revised our proposal for some of the issues raised by the AER. In light of new information we have applied a 5% per annum compound reduction to our capital program. Our revised proposed capital program of $1.6 billion will ensure we efficiently deliver safe, reliable and affordable electricity services to our customers in a financially sustainable manner.

The purpose of this chapter is to address the matters raised in the AER's draft decision and explain our revised forecast, the method used to develop it and the key highlights of the program.

Our proposed forecast capital expenditure (capex) in our initial proposal was 43%[104] lower than allowed capital expenditure for 2009-14.[105] In our initial proposal, we provided the AER with information to demonstrate the efficiency and sustainability of our capital expenditure. The lower capital expenditure reflected strategic re-alignment of objectives under industry reform, a greater focus on minimising network charges for our customers and observed reductions in the rate of growth in peak demand.

In the draft decision, the AER has rejected our proposed capex and substituted an amount of $1,070.4 million, or a reduction of 38.7% to Endeavour Energy's initial proposal. We consider the numbers analysed and substituted by the AER contain errors which have inhibited our ability to understand and engage with the draft decision.

In our response, we draw the attention of the AER to the evidence we submitted in our initial proposal which the AER has not adequately considered and additional information in response to the matters raised. We also show that the AER has not accounted for our network design and characteristics and prescribed inappropriate and unsustainable network outcomes.

Endeavour Energy considers the substitute capex would not promote the long term interests of consumers and is insufficient to maintain a safe and reliable network in the 2014-19 period. The marginal network charge reductions delivered by a further reduced capital program will be outweighed by a future increase in capital expenditure required to correct any period of under-investment in the network. Our response to the AER's draft decision is fully set out in this chapter and supporting attachments.

Our revised proposal for standard control services capital expenditure for the 2014-19 regulatory control period is $1,576.3 million as shown in Table 5.1. The changes include updating labour escalators and a re-prioritisation of our proposed program based on the latest available information such as network condition and demand forecasts and to address matters that the AER raised in its draft decision.

[104] Inclusive of type 5 and 6 metering and ANS costs for comparison in real terms to the 2009-14 period allowance in real terms.

[105] In real terms.

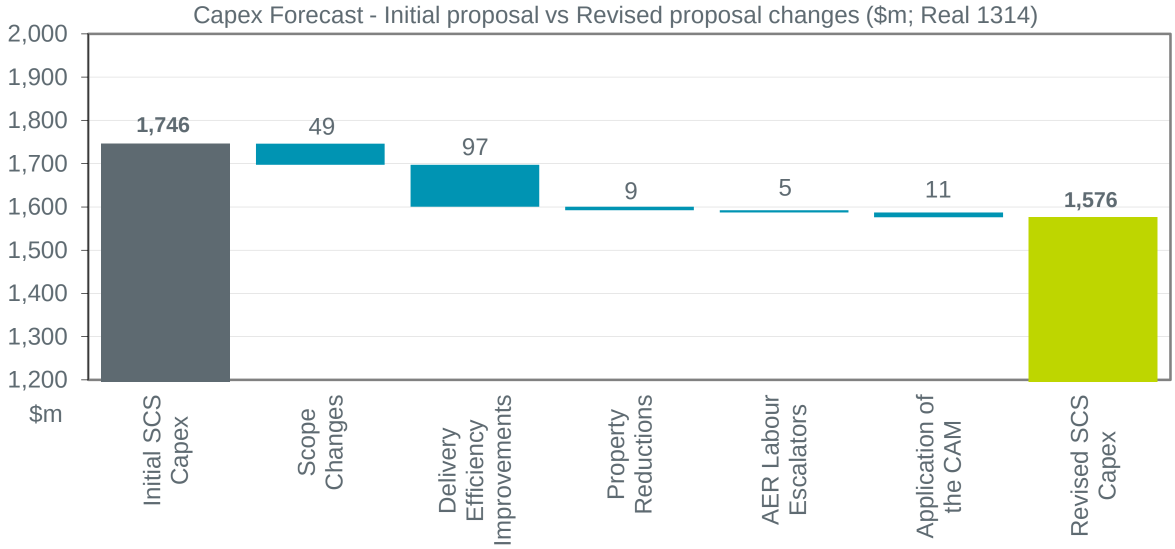
5 CAPITAL EXPENDITURE

Table 5.1: Revised forecast standard control capital expenditure over the 2014-19 regulatory control period

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Endeavour Energy initial proposal	432.9	361.1	314.3	325.7	312.0	**1,746.0**
AER draft determination	285.1	223.1	184.1	194.4	183.7	**1,070.4**
Endeavour Energy revised proposal	411.1	337.57	286.6	277.05	264.1	**1,576.3**

The drivers for the 9.7% real reduction between Endeavour Energy's initial proposal and this revised proposal are depicted in Figure 5a.

Figure 5a: Changes in Endeavour Energy's capital program between initial proposal and revised proposal ($m; Real 13-14)



The principal drivers for the reduction are:

- A revised capital program scope for the 2015-16 to 2018-19 period reflecting agreed aspects of the AER's draft determination and Endeavour Energy's revised risk assessed program.
- The progressive implementation of further efficiencies in the delivery of the capital program by an average of 3.3% per annum compounding over the four year period of 2015-16 to 2018-19 while maintaining the scope of the program submitted in this revised proposal.

5 CAPITAL EXPENDITURE

5.1. Framework for AER decision

The NER provides guidance as to the overall objective of capital expenditure. A series of factors and criteria are specified to enable the AER to assess whether the proposed capex is both a prudent and efficient forecast.

The NER requires the AER to make a constituent decision on whether to accept, or reject and substitute the forecast capital expenditure (capex) and forecast operating expenditure (opex) that Endeavour Energy sets out in its building block proposal for standard control services. To enable the AER to make its constituent decision, Endeavour Energy's building block proposal must include the total forecast capex and forecast opex for the relevant regulatory control period which the DNSP considers is required in order to achieve the capital and operating expenditure objectives.

5.1.1 Framework for AER's draft decision on capex

The Rules require the AER to make a number of constituent decisions as part of its distribution determination. Clauses 6.12.1(3) relate to the AER's draft decisions on the forecast capex proposed by a DNSP in its building block proposal. The AER either:

> *"(i) acting in accordance with clause 6.5.7(c), accepts the total of the forecast capex for the regulatory control period that is included in the current building block proposal; or*
>
> *(ii) acting in accordance with clause 6.5.7(d), does not accept the total of the forecast capex for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the Distribution Network Service Provider's required capex for the regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors;"*

In making its decision, the AER is guided by the objectives, criteria and factors in the Rules. In doing so, it must also consider the overall principles of assessment that have been described by the Rule maker, the AEMC in recent rule determinations. Each of these areas is discussed below.

5.1.2 Objectives, criteria and factors

The Rules set out a framework such that Endeavour Energy is required to propose total capex and opex that Endeavour Energy considers is needed to produce the outputs or outcomes that are encapsulated in the Rules. These outputs/outcomes are specified in clause 6.5.6(a) and 6.5.7(a) of the Rules and are termed the operating and capital expenditure objectives (together expenditure objectives).

Clause 6.5.6(a) and 6.5.7(a) requires Endeavour Energy to include in its building block proposal the total forecast opex and capex for the 2014-19 period which Endeavour Energy considers is required to achieve each of the expenditure objectives.[106]

The AER is required to make a decision on the total forecast expenditure proposed by Endeavour Energy. The Rules provide that the AER must accept the forecast expenditure included in Endeavour Energy's building block proposal if the AER is satisfied that the total forecast expenditure reasonably reflects the expenditure criteria. These expenditure criteria (clause 6.5.7(c)) are:

> *"(1) the efficient costs of achieving the capital expenditure objectives; and*
>
> *(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*

[106] These objectives are:(1) meet or manage the expected demand for standard control services over that period; (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services; (3) to the extent that there is no applicable regulatory obligation or requirement in relation to: i. the quality, reliability or security of supply of standard control services; or ii. the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: iii. maintain the quality, reliability and security of supply of standard control services; and iv. maintain the reliability and security of the distribution system through the supply of standard control services; and(4) maintain the safety of the distribution system through the supply of standard control services. (Objective 4)

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives."

In deciding whether or not the AER is satisfied that Endeavour Energy's proposed total forecast expenditure reasonably reflects each of the expenditure criteria, the AER must have regard to the expenditure factors.[107] The purpose of the specific capex objectives, criteria and factors outlined above is to support the achievement of the NEO in guiding both the development and assessment of a DNSPs proposed capex. The NEO sets out the purpose of the NEL and regulatory framework, that being:

"The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system."

Therefore, the overall objective of the Rules governing the AER's draft decision is to ensure that the forecast expenditure is to achieve a safe and reliable supply of standard control services at an efficient cost in the long term.

5.1.3 Changes to the NER in 2012

As part of the 2012 Rule change on Economic Regulation of Network Service Providers, the AEMC reviewed the decision making framework for capex. The AEMC largely maintained the existing framework in the Rules that were applied to making our 2009-14 determination. This included maintaining the structure of the objectives, criteria and factors.

At the time, the AER clarified the process that the AER should follow when making its decision on expenditure forecasts. The AEMC emphasised the following key principles underlying the assessment process:

- **Assessment process must start with a DNSP proposal** – The proposal is necessarily the procedural starting point for the AER to determine a capex or opex allowance. The NSP has the most experience in how a network should be run, as well as holding all of the data on past performance of its network, and is therefore in the best position to make judgments about what expenditure will be required in the future. Indeed, the NSP's proposal will in most cases be the most significant input into the AER's draft decision.
- **The AER must accept a proposal that is 'reasonable'** – The criteria require that the AER must accept a proposal if it is reasonable. The AEMC noted that the AER is not "at large" in being able to reject the NSP's proposal and replace it with its own. The obligation to accept a reasonable proposal reflects the obligation that all public decision makers have to base their decisions on sound reasoning and all relevant information required to be taken into account.
- **Consider the probative value of information submitted by stakeholders** – To the extent the AER places probative value on the NSP's proposal, which is likely given the NSP's knowledge of its own network, then the AER should justify its conclusions by reference to it, in the same way it should regarding any other submission of probative value.

[107] The first three factors were deleted as part of the 2012 Rule change. The factors in the Rules are therefore as follows:(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; (5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods; (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; (6) the relative prices of operating and capital inputs; (7) the substitution possibilities between operating and capital expenditure; (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;(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; (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); (10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and (11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s); (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 expenditure factor.

- **The AER's assessment techniques in making its analysis are not limited** – While the NSP's proposal will in most cases be the most significant input into the AER's draft decision, it should be only one of a number of inputs. Other stakeholders may also be able to provide relevant information, as will any consultants engaged by the AER. In addition, the AER can conduct its own analysis, including using objective evidence drawn from history, and the performance and experience of comparable NSPs. The techniques the AER may use to conduct this analysis are not limited, and in particular are not confined to the approach taken by the NSP in its proposal.
- **The test of 'reasonable' must equally apply to the substitute amount** – While the AER must form a view as to whether a NSP's proposal is reasonable, this is not a separate exercise from determining an appropriate substitute in the event the AER decides the proposal is not reasonable. Both the consideration of "reasonable" and the determination of the substitute must be in respect of the total for each of capex or opex. The AER, whenever it determines a substitute for a NSP's proposal, is not constrained by the capex and opex criteria from choosing the best substitute it can determine.

Expenditure Forecast Assessment Guideline

In addition to the changes outlined above, as part of the 2012 rule change on Economic Regulation of Network Service Providers, the AEMC provided for the development of an expenditure forecast assessment guideline. The purpose of this guideline is for the AER to specify the approach it proposes to use to assess the expenditure forecasts that form part of a DNSPs regulatory proposal and to outline the information the AER requires for the purposes of this assessment.

We consider that the purpose of this guideline is to provide greater certainty and transparency to the approach the AER utilises in assessing a DNSP's forecast expenditure. Ultimately, this guideline should support the achievement of the capex objectives and criteria and align to the capex factors. During the AER's development of the guideline Endeavour Energy, and the NSW DNSPs, noted their concerns with the proposed guideline.

> *"The role of the guideline is to specify the approach the AER proposes to use to assess the forecasts of operating expenditure (opex) and capital expenditure (capex), and the information the AER requires for the purpose of that assessment.*
>
> *We are concerned that the guidelines only provided limited information on the principles or process the AER would follow in making its decision under the Rules framework. The AER has not been clear on how its approach relates to its discretions under the Rules, or the fundamental principles of administrative decision making….*
>
> *….In our view, the AER should methodically outline the principles underlying its assessment approach, and how these relate to its decision consistent with clause 6.5.6 and 6.5.7 of the Rules."*[108]

We did not consider that the guideline provided an opportunity to depart from the regulatory framework or alter its intent. Rather the guideline should simply provide greater certainty as to how the AER will conduct its assessment within the regulatory framework.

In addition to this guideline the AEMC introduced a requirement for DNSPs to inform the AER of the forecasting methodology it proposes to use to prepare the expenditure forecasts that form part of our regulatory proposal. This submission must occur six months prior to the submission of a DNSP's regulatory proposal. We consider this is to provide the AER with further clarity as to the forecasting methodology we intend to use given our circumstances. This is to enable the AER to assess our regulatory proposal, which forms the procedural starting point of the AER's assessment, with this knowledge in mind.

[108] NSW DNSPs submission on AER expenditure forecast assessment guidelines issues paper – 14 March 2013, 20 September 2013, page 4

As above, we consider in combination the intent of these two rule changes is to increase the level of transparency and objectivity of the expenditure assessment process by providing greater certainty for both DNSPs and the AER.

5.2. Our initial proposal

In our initial proposal submitted in May 2014 we provided the AER with detailed information to demonstrate the efficiency and prudency of our proposed capex.

In our initial proposal, we provided significant evidence demonstrating the efficiency of our proposed capital program and our responses to changing conditions. The 2014-19 proposed capex was designed to maintain the necessary improvements made in 2009-14 and meet and manage expected pockets of spatial demand growth.

At the time of the 2009-14 determination, the AER scrutinised our proposed capex in great detail, assessing our capex categories and our investment need. The AER made minor reductions to our proposed capex based on its thorough assessment accepting the need for increased investment in full knowledge of the associated prices increases.

In delivering the program, we have made significant improvements for our customers. We have improved reliability, increased security of supply, and replaced deteriorated assets that posed safety risks to our customers and workforce. In delivering our programs we have focused on efficiencies and innovations, including targeted efficiencies to the capital program. We have incorporated these improvements into our forecasts to manage our network in a way that serves the long term interests of our customers.

Our customer research indicated that customers wanted lower prices, current service levels and no price shocks. A central aspect of our proposal was to show how the proposed capex met the long term interests of our customers. We explained the drivers of our capital program and how it related to the achievement of the capital objectives, criteria and factors. We also showed how we had considered the sustainable level of expenditure we could achieve in our circumstances, and how we had incorporated an improved governance framework into our forecasts to improve the prudency of our program, drive ongoing efficiency and its affordability for our customers.

Our proposed program of $1,746.0 million addressed customers' concerns as it:

- was 43% lower than the efficient allowance for the 2009-14 period;
- contributed to delivering a price path at or below CPI;
- sought to meet and manage expected demand and customer growth;
- sought to meet our obligations, including maintaining current levels of service and security of supply; and
- represented a sustainable level of investment for future periods.

5.2.1 Achieving the capex objectives

Endeavour Energy included in the building block proposal a total forecast capital expenditure for the 2014-19 period that Endeavour Energy considers is required to carry out the necessary activities so as to achieve each of the capex objectives listed in clause 6.5.7(a) of the Rules. This total forecast capex is made up a number of cost categories. These cost categories represent the costs of undertaking a set of interrelated activities and to address the various expenditure drivers to achieve each of the capex objectives.

We outlined the components of our proposed total forecast capex for the 2014-19 period and demonstrated how these cost components are required to achieve each of the expenditure objectives listed in clause 6.5.7(a) of the Rules. The expenditure objectives effectively define the activities that Endeavour Energy needs to undertake and specify the capabilities, systems and personnel that Endeavour Energy needs to have in place. Consequentially, achieving the expenditure objectives give rise to expenditure which is either of a capital or operating nature.

The table below provides a summary of the drivers of investment for each of our capital plans, and how these relate to one or more capex objectives. We note that more detailed information on our forecast methods and programs can be found in our forecasting methodology (Attachment 0.08 to our initial proposal) and in our capital expenditure chapter in our initial proposal.

Table 5.2: Capital plans and investment drivers

Capital plan	Capex objectives achieved
Transmission Network Planning Review	1 and 3
Strategic Asset Renewal Plan	2,3 and 4
Distribution Works Program	All
Reliability Works Program	2 and 3
Strategic Asset Management Plan	All
Technology Plan	All
Property Plan	All
Fleet and Other Support Plan	All

Transmission Network Planning Review

Every year we review the loading on each element of the sub-transmission network given the forecast demand for each year in the ten-year forecast period. We review the 37 load areas of our sub-transmission network. Where capacity shortfalls are noted, augmentation projects are proposed with expenditure forecast at a time appropriate to address the network need. The sum of all identified projects forms the ten-year plan for augmentation of the sub-transmission network.

The key driver of investment is growth that may impact on the ability of the network to supply the required demand with an appropriate level of supply security. It should be noted that a reduction in supply security may lead to a reduction in reliability levels. This plan therefore achieves the following capex objectives:

- Objective 1 – To increase capacity of the sub-transmission network to cater for changes in peak demand arising from new connections and increased demand from existing customers.
- Objective 3 –To replace and increase capacity to maintain the reliability, security and quality of supply.

We note that the removal of Schedule 1 of our Design, Reliability and Performance licence conditions means that we no longer have to meet specific security criteria. In developing our forecast capex we have prudently given consideration to opportunities to defer investment where the resultant decline in security may be prudent and efficient.

Strategic Asset Renewal Plan

This plan identifies all replacements of distribution and sub-transmission network assets. The underlying driver of investment is asset condition and fitness for purpose to meet ongoing safety, reliability and environmental obligations. We consider that the replacement of assets enables us to meet specific safety standards required by legislation and also to maintain the level of safety from the previous period. As such the plans achieve the following capex objectives:

- Objective 2 – To replace assets on the distribution and sub-transmission network in line with our underlying regulatory obligations to provide a network that meets safety and environmental standards.

- Objective 3 – To replace assets to maintain the reliability of supply across the network.
- Objective 4 – To replace assets on the distribution and sub-transmission network to maintain our safety standard based on previous performance.

Distribution Works Program

Every year we review the capability of the 11/22kV distribution network to safely supply the loads connected to it in compliance with network and regulatory standards. Limitations in network capacity, voltage regulation and capability to withstand faults are identified and a suite of projects developed to address these. This plan identifies forecast capex for augmentations on the distribution network. The underlying driver of investment is growth and the impacts that it has on the ability of the network to meet expected demand, safety and other regulatory obligations. As such, we consider the plan achieves the following capex objectives:

- Objective 1 – Decisions to increase capacity of the distribution network are related to peak demand arising from new connections and increased demand from existing customers.
- Objective 2 – Decisions to increase capacity on the distribution network are related to our underlying regulatory obligations to provide a network that meets mandated technical performance standards.
- Objective 3 – Decisions to replace and increase capacity are designed at maintaining the reliability, security and quality of supply.
- Objective 4 – Decisions to increase capacity on the distribution network are related to maintaining our safety standard based on previous performance.

Reliability Works Program

This plan identifies any additional capex required to maintain levels of reliability in accordance with meeting reliability performance standards specified in the NSW Reliability and Performance (RP) licence conditions (Schedules 2 and 3 relating to average performance standards and minimum standards for feeders respectively). It also meets customer expectations by addressing areas of poor reliability performance. The underlying driver of investment is maintaining reliability compliance, and therefore ostensibly meets Objective 2, however it is also intended to maintain existing levels of reliability across the network and therefore also meets Objective 3.

Strategic Asset Management Plan

This plan is Endeavour Energy's overall system capital plan that brings together the capital works and associated expenditure forecasts of all the other capital expenditure plans. The intention is to ensure that an integrated program is developed that recognises the synergies that exist between the different plans and thereby develop a capex forecast that enables all the identified network needs to be met in the most efficient way. As such we consider that this plan achieves the following objectives:

- Objective 1 – Decisions to increase capacity of the distribution and sub-transmission network are related to peak demand arising from new connections and increased demand from existing customers.
- Objective 2 – Decisions to replace assets and increase capacity on the distribution and sub-transmission network are related to our underlying regulatory obligations to provide a network that meets mandated technical performance standards.
- Objective 3 – Decisions to replace and increase capacity are designed at maintaining the reliability, security and quality of supply.
- Objective 4 – Decisions to replace assets and increase capacity on the distribution network are related to maintaining our safety standard based on previous performance.

Technology Plan

This plan identifies infrastructure, platforms, applications and devices required to support our network and corporate functions. This includes the operational technology required to control and manage our network. Given that the technology plan spans network and support investment, the drivers of investment include safety, growth, asset condition and network support.

Technology provides a necessary supporting activity to enable us to meet our network objectives and to fulfil our corporate obligations. Operational IT Technologies such as SCADA are required to directly operate and monitor network equipment and therefore are linked to maintaining the safety and reliability of the network. Non-system IT assets provide operational support to our employees to perform building activities required to achieve the capex objectives.

It is essential that Endeavour Energy remains current and connected to the global supply chain and the technology advancements adopted by the industry. These technologies enable us to more effectively monitor and control our network and make investment decisions based on a better understanding of asset condition and performance. Failure to keep abreast of these advancements would leave us unable to provide the services demanded by the customers of a 21st century power distribution network.

In this respect, our forecast capex is to achieve all the capex objectives as a whole, given that they are essential to performing our network activities.

Property Plan

The corporate Property Plan includes capex to support the housing of employees. It includes depots and office accommodation. The underlying driver of investment is to support the network. Corporate property provides a necessary supporting activity by housing our employees in office and Field Service Centre (FSC) accommodation such that they can perform their network activities in a safe and efficient manner.

One specific factor that is considered in this plan is the need for FSCs to be located such that employees are able to respond efficiently to reliability issues. We monitor where customer growth is occurring and develop plans to locate or relocate FSCs close to population centres. In this respect, our forecast capex is to achieve all the capex objectives as a whole, given that they are essential to performing our network activities.

Fleet and Other Support Plan

These plans identify vehicles and equipment used to provide our network services, and other capex such as plant and equipment. Fleet is used to transport employees to undertake capital works (for example pool vehicles) or directly used to build assets (such as elevated work platforms). Plant and equipment are used directly by our employees in network activities such as maintenance and construction. In this respect, our forecast capex achieves all the capex objectives as a whole, given that they are essential to performing our network activities.

In addition, the ‘meeting the Rules’ section of our initial proposal provided a detailed explanation of how we considered our proposed capex satisfied the capex criteria and factors.

5.2.2 Satisfying the capex criteria with regard to the capex factors

Our initial proposal was accompanied by expert economic opinion from NERA Consulting on how to interpret the capex criteria in the Rules, and on how to demonstrate that the forecast capex reflected these criteria with regard to the factors.

A key element of NERA’s advice was that there is no external, observable measure that can be relied upon to demonstrate and/or conclude that the total forecast expenditure is efficient. In this context, NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent.
- 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.
- We showed that NERA's practical approach reflect the capex factors that the AER must consider in deciding whether it is satisfied that the forecast expenditure reasonably reflects the expenditure criteria.

Methodology employed by Endeavour Energy to derive forecast capex

In our initial proposal we demonstrated that we have a comprehensive approach to forecasting our capex for the 2014-19 period.

Our forecasting process involves both top down and bottom up methods in developing our capex forecast. In our proposal we outlined our use of the AER's repex and augex models, our Value Development Algorithm (VDA), WARL, our understanding of proposed developments gained from developers and planning authorities, and the use of probabilistic/risk-based capacity planning to identify and manage resultant constraints. This is then overlaid with the risk prioritisation approach considered by the Board for the overall capex program. This approach complements a bottom up method which examines in detail:

- safety, environment and regulatory requirements;
- asset condition;
- forecast demand and development activity;
- asset utilisation;
- suitability of the assets for their function;
- present demand on the asset;
- historical demand placed on the asset over its service life;
- maintenance and service history;
- knowledge of equipment type faults;
- the unique risk relating to those assets; and
- pre-defined criteria that form the basis of asset health index and trigger a flag for asset refurbishment and replacement (for major equipment groups).

We have a prudent and robust process in place to ensure that our capex program represents a reasonable estimate of the lowest cost solution to address a genuine network need. Our governance framework involves several stages and checks to continually assess the project need and evaluate its execution.

As part of this process the Board considered the overall risk based portfolio, including a number of projects and programs at selected constraint points, when determining an appropriate network risk versus expenditure position. The Board were appropriately informed of both the prioritisation process and the risk outcomes resulting from deferring expenditure.

In our initial proposal we sought to show that the resultant forecast was 'fit for purpose' in that it ensured that the nature of each capex category and its relevant underlying drivers are appropriately accounted for such that the resulting forecast capex is reflective of the efficient costs that a prudent operator would require to achieve the capex objectives. This process gave us confidence that our total forecast capex would reasonably reflect the capex criteria and ensures that the National Electricity Objectives and the Revenue and Pricing Principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient cost we expect to incur in the 2014-19 period.

Our initial proposal also identified the relevant opex factors that align to assessing the prudency of forecasting approach:

- Substitution possibilities between operating and capital expenditure (expenditure factor 7). Our forecasting process considered the consequential impact of efficient capital investment on our future opex requirements. For instance we identified that reductions in replacement capex will degrade the health of assets on the network, and increase the efficient maintenance costs. We also considered how IT and property capex may impact opex for these activities.

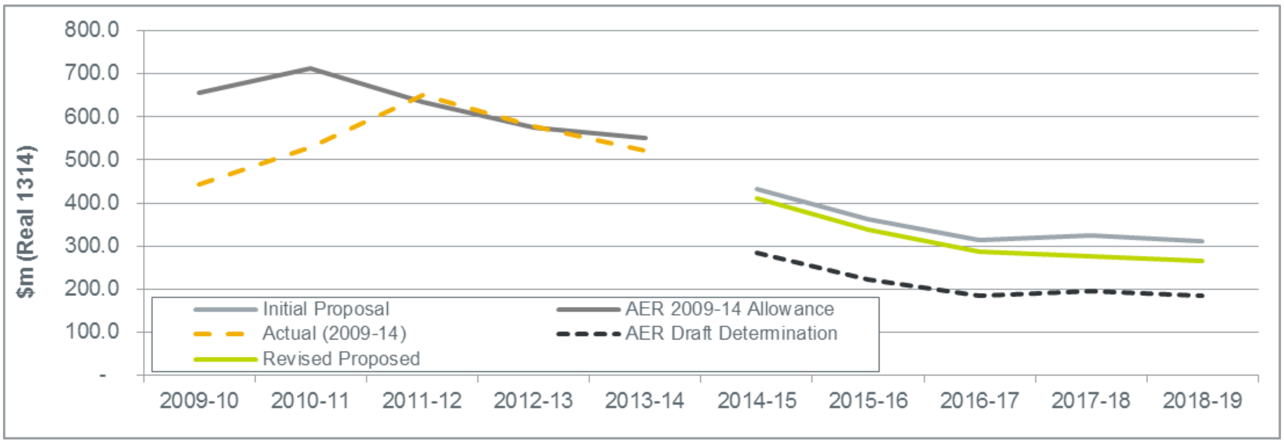
- The extent to which Endeavour Energy has considered and made provision for efficient non network alternatives – We considered the extent to which demand management activities taken to defer capex would impact opex in the 2014-19 period.
- Relative prices of capital and operating inputs (expenditure factor 6).
- The extent to which the expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity customers. (expenditure factor 5A)

Indicators to assess whether process results in efficient cost

NERA's advice suggested there are partial indicators and other factors that would assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the Rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria. Accordingly, our initial proposal addressed these factors to satisfy the AER that our forecast capex meets the criteria.

Capex factor 5 states that the AER must have regard to the actual and expected capex of the DNSP during any preceding regulatory control period. We demonstrated that our proposal was grounded on our efficient performance in the past, and that this had formed an important element of our regulatory proposal. We showed that we performed significantly better than the targets that the AER had determined were efficient, as can be seen in Figure 5b below.

Figure 5b: Total Capital Expenditure Forecast 2010-2019



This performance was achieved by responding to changed conditions and implementation of a number of delivery efficiencies. It has set a solid platform for Endeavour Energy in ensuring that the forecast capex for the 2014-19 reasonably reflects the efficient costs that a prudent operator would need to achieve the capex objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

Capex factor 4 requires that the AER must consider the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital/operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period. 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. The AER did not release its first benchmarking report in September 2014 as required under clause 6.27(d) of the NER.

5 CAPITAL EXPENDITURE

In our initial proposal, we submitted a comprehensive report on the limitations and role of benchmarking as a partial indicator (Attachment 0.12). Our analysis identified that benchmarking has inherent limitations such as the inability to conduct 'like for like' analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistical principles. We noted that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. Importantly, it should not be used to reject a DNSP's proposal, or as a basis to substitute the forecast given the inherent limitations as a tool.

We placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast. This was due to our assessment of tools that the AER was developing which we considered did not meet criteria for an effective benchmark as developed by the Productivity Commission. We complemented our analysis by providing a report by Huegin Consulting which provided a factual demonstration of the limitations and shortcomings of benchmarking analysis.

Finally we showed that capex factor 9, which is the extent to which forecast expenditure is referable to arrangements with other persons that do not reflect arm's length transactions, is not applicable to our circumstances, and is therefore is not a required check on our forecasting process.

5.3. AER's Draft Decision

The AER has rejected our proposed capital expenditure and determined a substitute capital expenditure allowance of $1,070.4 million. This program would not be efficient or sustainable and will result in increased operating maintenance costs and jeopardise the safety of customers, contractors and employees and place at risk the security and reliability of the network in 2014-19 and subsequent periods.

Table 5.3: AER's draft decision compared to initial proposal (excluding capital contributions)

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Endeavour Energy proposal	432.9	361.1	314.3	325.7	312.0	**1,746.0**
AER draft determination	285.1	223.1	184.1	194.4	183.7	**1,070.4**
Difference	147.8	138.0	130.2	131.3	128.3	**675.6**
% Change	34.1%	38.2%	41.4%	40.3%	41.1%	**38.7%**

Source: AER, 'Draft Decision – EE 2014 – Consolidated Capex Forecast – November 2014', Table 1.1

This is a 38.7% reduction to our proposed program which was made because the AER considered our overall capex program did not result in the lowest sustainable cost based on a top down assessment coupled with bottom up analysis of volumes and costs by category driver.

In making its assessment the AER relied on data from the Reset RIN to assess the forecast capex by driver; replacement, augmentation, connections, non-network and capitalised overheads. The AER's method to derive the substitute was to rely on a combination of modelling, benchmarking analysis and consultant advice.

In its draft decision, the AER considered that our capital program did not represent an efficient level of expenditure or reflect the network condition, declining demand and consumption and reduced licence conditions. The AER considered that our risk management framework is inadequate and that a higher degree of risk could be tolerated whilst meeting our obligations as a DNSP to operate and maintain a safe, secure and reliable supply of electricity. Specifically:

> *"Firstly, Endeavour Energy's forecasting methodology applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for all its capex categories (except for information and communications technology). It does not combine this with the application of a top-down assessment to check or test whether these estimates are efficient. The drawback of deriving an estimate of capex solely by applying a bottom-up assessment is that of itself it does not provide any evidence that the estimate is efficient.*
>
> *Secondly, Endeavour Energy's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is excessively conservative. This is evident in Endeavour Energy's failure to fully justify the timing and priority of its proposed forecast capex. Ultimately, this excessively conservative approach to risk means that Endeavour Energy is forecasting more capex in the 2014–2019 period that is necessary to achieve the capex objectives."*[109]

The AER then assessed the proposed capex by driver to determine the reductions and substitute amounts at the category level. The AER purported to:

- Reject augex of $426.1 million and substitute a forecast amount of $351.8 million, a 17.4% reduction;
- Reject repex of $1,021 million and substitute a forecast amount of $661.1 million; a reduction of 35.2%;
- Reject reliability improvement capex of $65.3 million and substitute a forecast amount of $0, a reduction of 100%;
- Accept connections capex of $105.8 million;
- Reject non-network capex of $176.4 million and substitute a forecast amount of $163.3 million, a reduction of 7%;
- Reject labour cost escalators although further information is required before the AER can make a reduction to the capex forecast; and
- Accept capital contributions of $357 million.

These reductions were made in consideration of top down factors such as benchmarking analysis, reducing demand, 2009-14 period investment, network utilisation, amendments to the licence conditions and the risk management and governance framework. In conducting its benchmarking analysis the AER considered its draft decision accounted for the organisational and environmental factors that may impact the results. In particular, the AER examined the factors raised in the Evans & Peck report attached to Ausgrid's regulatory proposal and concluded that Endeavour Energy did not have a distinct cost advantage or disadvantage that invalidated the benchmarking analysis.

These reductions also relied on top down assessment tools such as repex, augex (in part), project reviews and consultant advice. For the augex forecast the AER relied on a report provided by WorleyParsons and for repex the AER relied on a report provided by EMCa. The majority of the repex was assessed using the repex model with the unmodelled repex programs subjected to engineering review.

In assessing Endeavour Energy's proposed capital program there were a number of issues the AER were unable to form a view on at the time of the draft decision. The AER expect Endeavour Energy's revised proposal to contain:

- a breakdown of the component of the capital forecast that relates to labour escalation so the AER can apply a similar adjustment made to the opex escalation;
- consideration of the latest VCR figure developed by AEMO in our project assessments;
- latest demand forecast and any associated revisions to the capital program;
- clarification of the capital contributions proposed;

[109] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, pages 19-20

- clarification of the amount of overhead that should be allocated to non-network capex;
- evidence justifying the component of the proposed reliability expenditure that relates to Schedule 3 licence conditions; and
- views on whether an explicit reduction to system capex is required to account for demand management activities.

5.4. Revisions to address AER's draft decision

In response to the AER's draft decision and reasoning, we have sought to assess whether we need to make revisions to our initial proposal to incorporate matters raised by the AER.

The purpose of this revised proposal is to consider the AER's draft decision and to revise our initial proposal to address the matters raised. We have sought to develop a capex forecast that is the efficient and prudent cost of maintaining a safe, reliable and secure supply of electricity. As such, we have considered the AER's draft decision in detail to understand whether amendments are required to the proposed program. In doing so we have also sought the advice of specialist consultants regarding the issues raised by the AER.

For the most part, we have not revised our proposal in response to the AER's conclusion. Our primary concern is that the AER's draft decision is flawed for a number of reasons and as such we will not be afforded a reasonable opportunity to recover our efficient costs in maintaining a safe and reliable network. This is for three reasons:

- The AER's draft decision contains substantive numerical errors in the capex numbers assessed and substituted.
- The AER did not make its draft decision in accordance with the framework required under clause 6.5.7 of the Rules and relevant guideline and this has led it to make an incorrect decision.
- We consider that the substantive issues raised by the AER concerning the capex categories are based on flawed analysis, unreasonable views and have ignored our circumstances.

While the key elements of our initial proposal remain intact, we have made changes based on the latest available information to ensure our proposed program continues to represent the efficient and prudent cost of managing our network. We initially proposed $1,746.0 million ($2013-14), we have reduced this program by 9.7% to $1,576.3 million ($2013-14), the key changes being:

- Updated real labour escalation – We have made revisions to our labour escalators to reflect the changes made by the AER in its draft determination; and
- The latest available information on our labour costs, demand forecasts and more aggressive productivity targets.

The revised program is contained in Table 5.4 below in the categories initially proposed by Endeavour Energy (for comparison). For comparison to the RIN categories, these proposed amounts are also provided by RIN category in section 5.5 of this chapter:

Table 5.4: Revised forecast capital expenditure over the 2014-19 regulatory period

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Growth	137.4	88.7	78.3	95.4	73.1	**472.9**
Asset renewal/replacement	216.8	210.3	167.3	140.6	139.4	**874.4**
Reliability	6.8	7.1	7.4	7.8	8.3	**37.3**
Compliance	-	-	-	-	-	**-**
Other system assets	1.0	4.1	5.0	4.6	13.2	**27.9**
Total system	**362.0**	**310.1**	**258.1**	**248.4**	**234.0**	**1,412.6**
Non-system assets	49.0	27.3	28.6	28.6	30.1	**163.6**
Total	**411.1**	**337.5**	**286.6**	**277.0**	**264.1**	**1,576.3**

5.4.1 Proposed capex and numerical errors

The AER has used RIN figures to assess our regulatory proposal. The RIN 'balancing item', which includes capital contributions, has been allocated to repex, augex and connections. Capital contributions are accepted by the AER but reductions made to figures by the AER are inclusive of them. This and other errors mean the AER's draft capex reduction of 38.7% is overstated by at least 14.3%.

The purpose of this section is to identify the numerical basis for the AER's draft decision on capex, and to identify our concerns with the AER's draft decision as a result. Ultimately we seek to demonstrate that the AER's draft decision utilises incorrect proposed figures and as a result contains errors in both the assessment and substitute forecast.

In making the draft decision the AER, and its consultants, have relied on the Reset RIN data. The RIN data accompanied the regulatory proposal providing data in the manner and form specified by the AER. Endeavour Energy's proposed capex was contained in the initial proposal and accompanying post tax revenue model (PTRM). The RIN data bears limited resemblance to the information we use for BAU purposes as it is based on AER definitions and instructions. Whilst the figures provided in the RIN reconcile at the total level to those included in Endeavour Energy's proposal (as required by the RIN) we do not consider they should be represented as our proposal forecast.

Our concerns with the RIN data were articulated in the basis of preparation which accompanied the RIN. Additionally, from a procedural perspective we consider our proposed capex should form the starting point and basis of the AER's assessment.

The AER have sought to assess the forecast capex on a direct cost basis, exclusive of overheads although occasionally gross figures are quoted by the AER. The AER's approach is summarised as follows:

> *"Endeavour Energy proposed total gross capex of $2,103 million ($2013-14) for the 2014-19 period. This forecast included an amount of capex ($432 million) referred to in the RIN as a 'balancing item'. We understand that the balancing item includes capital contributions and proposed reliability and improvement capex. We have removed the proposed reliability improvement capex from the balancing item given we have separately assessed this expenditure. We have included the proposed capital contributions from the PTRM ($356 million) in the balancing item (this differs from the amount of $302 million for capital contributions proposed in the RIN). We have then allocated this residual balancing*

item to augex, connections and repex by the proportion of each driver to total forecast capex. These adjustments have resulted in an increased amount for the proposed capex drivers as set out below.

- *Augex proposed $315 million (amended to $426 million)*
- *Connections capex $76 million (amended to $106 million)*
- *Repex proposed $740 million (amended to $1021 million).*

We note that there is a discrepancy between the amount of capital contributions proposed in the RIN ($302 million) and the amount proposed in the PTRM ($356 million). Further, we understand that Endeavour Energy has proposed total non-network capex for the 2014-19 period which is inclusive of overheads. We expect Endeavour Energy to clarify the proposed amount of capital contributions proposed for 2014-19, the amount of overhead that should be allocated to non-network capex and our approach of allocating the balancing item across the capex drivers in its revised regulatory proposal."[110]

In addition to this, a global adjustment factor and capitalised overheads rate of 13% is applied to convert the AER's draft decision by RIN categories to the PTRM asset classes. This smearing does not give effect to the AER's draft decision and simply applies a universal reduction to the categories that are the basis of the capital component of our revenue allowance.

Endeavour Energy could not reconcile the figures quoted by the AER in its capex decision. This is a key reason why we have not revised our forecast to adopt the AER's substitute amount. We sought consultant advice from Ernst & Young (Attachment 5.01 to this revised proposal) to understand the AER's draft decision and errors within it.

To summarise the AER, in error, has significantly overstated the system capex reduction of 30.86% by including capital contributions in the calculation. This is a result of the AER allocating the balancing item to the RIN categories despite the fact that this item primarily consists of the accepted capital contributions figure of $357 million. This means the AER has double counted, in part, the subtraction of capital contributions, along with other numerical errors. A summary of the issues is provided below by AER RIN category.

Assessment of repex figures

In its draft determination the AER has rejected Endeavour Energy's proposed repex forecast of $922.8 million ($2013-14) and substituted an amount $661.1 million ($2013-14) excluding overheads.

It is not clear what figure the AER's reduction was made to, different amounts are referenced throughout the draft determination none of which match the figure submitted by Endeavour Energy as our proposed forecast:

"Endeavour Energy proposed $1020.7 million ($2013–14) of forecast repex (after allocation of the balancing item and excluding overheads)…….a reduction of 35.2 per cent."[111]

"Figure A-8 shows that Endeavour Energy's proposed forecast repex of $992 million ($2013-2014) for the 2014–19 period."[112]

"Endeavour Energy proposed $739.7 million ($2013-14) of forecast repex (excluding capitalised overhead). We do not accept Endeavour Energy's proposal. We have instead included an amount of $661.1 million ($2013–14) in our alternative estimate, a reduction of 10.6 per cent."[113]

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[110] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, pages 11-12

[111] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 50

[112] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 49

[113] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 47

In the AER's detailed capex decision it appears the repex figure before the allocation of the balancing item is the number assessed (i.e. $740 million). Section 3.4.1 of the AER's draft decision Attachment 6 assesses $515 million of the repex and the remaining $225 million of "unmodelled repex" is assessed separately. The AER's draft decision substituted $519 million and $142 million respectively to develop an alternative forecast of $661 million, a $79 million reduction.

However, the draft decision quotes a reduction of 35.23% to repex based on the repex figure with the balancing item allocated. This percentage is hard coded as a "capex adjustment factor" however it is not clear whether the AER has assessed the $281 million allocated to the $740 million repex figure. The reduction implies a 100% cut to the $281 million however this primarily consists of capital contributions which have been accepted.
Therefore, the "capex adjustment factor" used by the AER is overstated significantly compared to the reduction made to the portion of the repex forecast the AER has actually assessed.

Specifically, Table 3.3 of the AER's 'Consolidated Capex Forecast – November 2014' (the AER capex model) uses the hard-coded figure of 35.23% to reduce the incorrect proposal figure from Endeavour Energy which in turn forms a significant part of the global system capex adjustment factor in Table 6.1 of the AER's model. We contend the correct figure in Table 3.3 is the 10.6% from the AER's draft decision which would reduce the 'Network capex adjustment factor' from 69.14% overall to 83.65% (i.e. a reduction of 16.35% rather than 30.86%).

Assessment of augex figures

Endeavour Energy proposed augex of $429.3 million including overheads, which included 'connections capex'. For the purposes of the Reset RIN this connections capex was captured in a separate specific category and accepted by the AER (discussed in the section below).

In its draft determination the AER has removed connections capex from Endeavour Energy's proposed augex forecast and added an allocation of Endeavour Energy's balancing item to arrive at an adjusted "proposed" augex of $426.1 million excluding overheads. The AER has then rejected this adjusted figure and substituted an amount $351.8 million ($2013-14) excluding overheads.

As such, the AER has effectively assessed gross augex, which includes capital contributions. The majority of the AER's reduction to augex is a global 15% cut based on a 10-20% recommended range provided by consultant WorleyParsons. This means that the capital contributions allocated to augex via the balancing item is also reduced by 15%. This is inconsistent with the AER's draft decision which approved all of our proposed capital contributions contained in the PTRM. Therefore, we consider the reduction made to the proposed augex is overstated and in error based on the AER's own decisions.

Unlike repex above, the AER assessed an augex amount inclusive of the balancing item (and therefore capital contributions) allocation. Additionally, Table 3.3 of the AER capex model has hard-coded the percentage reductions to the "proposed" augex. As such, we cannot readily determine what the intended reduction should have been nor the impact of this error on the 'network capex adjustment factor'.

Assessment of connections capex figures

Whilst Endeavour Energy did not explicitly propose 'connections capex', as it was included within the augex forecast, this was a category included in the AER's RIN. The AER approved the figure allocated to this category by Endeavour Energy in the Reset RIN of $105.8 million. As above, this is a gross capex figure as it includes capital contributions which have been allocated via the balancing item.

This means the capital contributions allocated to connections capex have in principle been approved twice by the AER. However, we do not believe this error would have an impact on the 'network capex adjustment factor' in Table 6.1 of the AER capex model as the adjustment factor in Table 3.3 (which is used to calculate the network capex adjustment factor) would be 0% regardless.

Assessment of reliability capex figures

In its draft determination the AER has rejected Endeavour Energy's proposed reliability capex forecast of $65.3 million ($2013-14) and substituted an amount $0 million ($2013-14). There was no allocation of the balancing item to reliability capex as it originally formed part of the balancing item and was removed from it to be assessed separately.

The $65.3 million of reliability capex proposed by Endeavour Energy was inclusive of capitalised overheads. The AER has applied a 13% cap to the capitalised overheads that can be allocated to the direct categories of expenditure in its draft decision. However, a reduction of 100% was made to the proposed reliability capex despite the fact that this figure included capitalised overheads.

The AER effectively reduces capitalised overheads by 52.9%; however, for the capitalised overheads allocated to reliability capex a 100% reduction has been made. This means the reduction is overstated as the AER has separately assessed and set capitalised overheads (as explained below) and thereby reduced the same portion of capitalised overheads in two places by differing amounts. Further investigation is required to quantify the impact (if any) of this error on the AER's draft decision.

Assessment of non-system capex figures

In its draft determination the AER has rejected Endeavour Energy's proposed non-network capex forecast of $176.4 million ($2013-14) and substituted an amount $163.3 million ($2013-14). A different reduction factor is applied in each year to convert the AER's draft decision into PTRM asset classes. Whilst the AER is specific in its reductions in its draft decision this PTRM asset class conversion spreads the cuts equally across all non-system asset categories. This means the AER has not given effect to its draft decision. It is also not clear how the reductions referred to in the AER's draft decision Attachment 6 reconcile to the numbers and percentages in the AER's consolidated capex forecast model.

In addition to this, the AER requested that the revised proposal clarify what component of the non-network forecast related to capitalised overheads. As per Endeavour Energy's AER approved CAM, there are no overheads allocated or added to non-network capex.

Assessment of capitalised overhead figures

In its draft determination the AER has rejected Endeavour Energy's proposed capitalised overheads forecast of $308.5 million ($2013-14) and substituted an amount $145.3 million ($2013-14). The AER has separately assessed Endeavour Energy's capitalised overheads and developed a substitute forecast based on a capped allocation rate of 12.99%. It is unclear how this approach is consistent with the AER's approval of Endeavour Energy's CAM in May 2014; however this is discussed in more detail in later sections.

The 12.99% cap was calculated by dividing the total capitalised overheads by the total standard control services gross capex (excluding overheads) for the 2009-14 period. Setting aside the legitimacy of such an approach, using a gross capex figure inflates the denominator with capital contributions which have no impact on capitalised overheads. This means the percentage cap developed by the AER is understated, meaning the resulting reduction to capitalised overheads is overstated in addition to the issue identified in the reliability capex section above.

Using a 'net' rather than 'gross' figure produces an overhead cap of 16.97% rather than 12.99%, which would result in capitalised overheads of $179.0 million ($2013-14) rather than the $145.3 million determined, in error, by the AER. However, as outlined in section 5.4.3 we do not accept this as a valid approach to determining capitalised overheads per Australian Accounting Standards and the AER approved CAM.

In addition to this, in Table 6.3 of the AER capex model the AER first sought to remove capitalised overheads from the amounts proposed by Endeavour Energy. However, the overhead factors in Table 5.2 of the AER capex model rely on Endeavour Energy "proposal" figures which include the balancing item and therefore capital contributions. This understates the portion of capitalised overheads percentage implied in Endeavour Energy's proposal.

Assessment of capital contributions

In its draft determination the AER has accepted Endeavour Energy's proposed capital contributions forecast of $356.9 million ($2013-14). However, this figure differed to that submitted by Endeavour Energy in the Reset RIN of $302 million. We note that this difference was due to the data relying on an earlier estimate of capital contributions. As outlined above, this figure represents the majority of the balancing item and we consider its apportionment across the RIN categories results in error. As noted in the revised proposal section, the capital contributions figures have been revised to reflect the latest available information.

Adjustment factors

As a result of the errors and issues outlined above we consider the AER has incorrectly assessed our proposed capex and substituted an amount in error. The network capex adjustment factor applied by the AER of 69.14% (a 30.86% reduction) is overstated. Sufficient information is not available to determine what the correct figure should be, primarily due to the unknown impact of the error on the augex decision.

However, in removing the approved capital contributions from the balancing item and utilising the 'correct' overhead rates and 10.7% repex reduction results in a network capex adjustment factor of 83.65% (a 16.35% reduction). This represents a reduction to the total proposed capex of 24% rather than 38.7% in the AER's draft decision noting the reduction would be even less if the impact of all the errors could be calculated.

We have raised this matter in discussions with the AER post the release of its draft determination and consider further discussions are required post the submission of this revised proposal.

5.4.2 Procedural issues with the AER's draft decision on capex

The AER, in its assessment has not demonstrated how our regulatory proposal was considered in detail. It also appears the AER has placed undue weight on benchmarking, departed from the expenditure forecast assessment guideline and failed to consider the consequences, logic and reasonableness of their substitute allowance. This has limited the scope to revise our regulatory proposal in response to the matters raised by the AER.

The purpose of this section is to identify specific failings with the AER's draft decision for capex in light of the framework outlined earlier in this chapter. At the overall level the AER have failed to engage with the detail of our regulatory proposal and consider our obligations and circumstances in their assessment. This is based on the AER's interpretation of the AEMC's intent in developing the September 2012 rule change:

> *"The AEMC removed the focus on a business' 'individual circumstances' as it could be an impediment to the use of benchmarking by the AER."*[114]

and

> *"We do not seek to interfere in the decisions a service provider will make about how and when to spend the total capex or opex allowance to run its network. The service provider is free to choose how to manage its allowance. For example, we do not approve individual capital expenditure projects that a distributor must then implement. Rather, we determine the sum total of revenue that we consider satisfies the requirements of the NEL and NER. Consistent with incentive regulation, it is then for the distributor to determine the particulars of how this allowance is applied in the next regulatory control period (usually five years)."*[115]

[114] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 14

[115] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 16

This interpretation by the AER, its unreliable and misguided use of benchmarking and its subsequent failure to engage with our initial proposal conveniently ignores the substance of the AEMC's removal of the individual circumstances phrase as part of the 2012 rule change:

> *"The Commission is of the view that the removal of the "individual circumstances" clause does not enable the AER to disregard the circumstances of a NSP in making a decision on capex and opex allowances. Benchmarking is but one tool the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal…………*
>
> *The Commission considers that the removal of the "individual circumstances" phrase will clarify the ability of the AER to undertake benchmarking. It assists the AER to determine if a NSP's proposal reflects the prudent and efficient costs of meeting the objectives. That necessarily requires a consideration of the NSP's circumstances as detailed in its regulatory proposal.*
>
> *Under the first expenditure criterion the AER is required to accept the forecast if it reasonably reflects the efficient costs of achieving the opex objectives. These include references to the costs to meet demand, comply with applicable obligations, maintain quality, reliability and security of supply of services and of the system. These necessarily require an assessment of the individual circumstances of the business in meeting these objectives. So to the extent that different businesses have higher standards, different topographies or climates, for example, these provisions lead the AER to consider a NSP's individual circumstances in making a decision on its efficient costs."*[116]

Whilst we accept that the AER does not set a capex allowance at the project level it has done so at the program level in its draft decision which implies certain safety and reliability outcomes by the AER in this decision. We consider the intent of the AEMC was to provide additional tools to the AER to help simplify its approach and focus its assessment on key areas. The rule change was not intended to undermine or revise the intent and approach outlined in the NER. There is no guidance or objective criteria that constitutes what revenue allowance satisfies the NEO.

There is detailed guidance in the NER to enable the AER to assess the components of the revenue allowance. For capex, there are the objectives, criteria and factors which prescribe the AER's assessment approach. We contend that the AER cannot satisfy itself that the capex forecast forms part of a revenue allowance that satisfies the NEO without conducting a detailed review. The individual circumstances and obligations of a business must be considered rather than constructing a hypothetical benchmark DNSP. In relying on benchmarking and high level analysis the AER has not understood the implications of its decision on safety and reliability outcomes and our ability to efficiently meet our obligations as a DNSP.

We have sought advice from R2A Due Diligence Engineers in regard to safety impacts of the AER's draft decision (report attached as Attachment 1.09) and Jacobs Group Australia in relation to engineering prudency and reliablity (reports attached as Attachment 1.13 and 1.14).

R2A's analysis indicated that:

> *"If Endeavour Energy were to operate within the constraints of the draft determination, then in the short term, the number of safety incidents, especially to employees, is expected to spike due to the change in safety culture associated with this scale of staff loss. In the longer term, this analysis indicates that for the foreseeable threats to members of the public considered in this review, a doubling in fatalities from network hazards would most likely occur. In addition, the likelihood of the Endeavour Energy network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) is increased by around 60%."*[117]

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[116] AEMC, Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 15 November 2012, p85

[117] R2A, Endeavour Energy Asset/System Failure Safety Risk Assessment, January 2015, p4

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Jacobs expressed the following views :

> *"In our opinion, the AER does not appear to have apposite consideration of the impact that the revised expenditure levels have on the risk exposure of the NSW DNSPs."*[118]

and

> *"Critically, in our review of the AER's discussions supporting the Draft Determination expenditure reductions we were unable to observe robust consideration of critical risk factors such as bushfires and public safety; where, in Jacobs' opinion the overarching thread focuses on costs versus reliability of supply.*
>
> *Our review of the Draft Determinations highlights a number of issues with respect to the AER's approach. Jacobs was able to observe apparent flaws in reasoning, poorly substantiated decisions, and an over reliance on speculative views in the AER's expenditure reduction decisions and the reasoning used to discount the NSW DNSP's Expenditure Proposals."*[119]

Assessment starting point

As outlined by the AEMC during the September 2012 rule change process, a DNSP's regulatory proposal constitutes the procedural starting point of the AER's assessment.

> *"The NSP's proposal is necessarily the procedural starting point for the AER to determine a capex or opex allowance. The NSP has the most experience in how a network should be run, as well as holding all of the data on past performance of its network, and is therefore in the best position to make judgments about what expenditure will be required in the future. Indeed, the NSP's proposal will in most cases be the most significant input into the AER's decision."*[120]

We contend that the AER has failed to demonstrate that it has assessed our regulatory proposal. Rather, it appears the AER, and its consultants, did not utilise the capex by driver proposed by Endeavour Energy as this included capitalised overheads. Instead, the AER analysed the RIN data which had capex by different drivers exclusive of overheads.

This RIN data included the apportionment of a balancing item across some of the categories despite it primarily consisting of capital contributions which were assessed and approved separately. In addition to leading to the errors discussed in the above section, we consider this approach also indicates that the AER did not engage with and assess our regulatory proposal as submitted.

Benchmarking report

As noted in Chapter 1, we consider the AER's draft decision did not follow proper procedures in reaching its conclusion, when it failed to publish the annual benchmarking report by 30 September 2014. In this respect, the AER failed to comply with an essential precondition to making its draft determination as set out in Clause 6.27(d) of the Rules.

Benchmarking is one of the factors the AER must have regard to in accepting or rejecting a DNSPs proposed capex. Specifically, 6.5.7(e)(4) states:

> *"the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;"*

[118] Jacobs, Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment, January 2015, p2

[119] Ibid. ,p5.

[120] AEMC, Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, page 111

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Rule 6.27(d) of the NER requires the first annual benchmarking report to be published by 30 September 2014. The AER released the report at the time of releasing its draft decision which heavily relied on the analysis contained in the benchmarking report. The final annual benchmarking report was therefore not subject to consultation required under 8.7.4(c) of the NER.

Additionally, the annual benchmarking report released by the AER covers the 2006-13 period rather than the most recent 12 month period as specified by 6.27(a). This creates the potential for misalignment of costs which may fall in different periods. One relevant example is the recent settlement of bushfire related claims by Victorian DNSPs which would not have been captured in the 2006-13 figures. It is worth noting with respect to this example that the full community cost of the fires due to the asset management practices of these DNSPs will never be reflected in figures captured by the AER's benchmarking report as these costs will not all be borne by the DNSPs.

Endeavour Energy also questions the selective use of a period commencing in 2006 prior to the introduction of stringent and mandatory jurisdictional licence conditions in NSW. Given the outputs and weightings selected by Economic Insights and the lack of a relationship between these outputs and the additional costs incurred through the licence conditions implementation, one would expect the results to show productivity of NSW distributors declining substantially. The report makes no attempt to examine the reasons for selecting 2006 to 2013, nor the resulting productivity results which are then not surprisingly biased against NSW DNSPs. In fact, as an illustration of the subjectivity of the time period, picking a period starting from any year from 2008 but ending in 2013 shows NSW performing above Victoria in all five periods (2008-13, 2009-13, 2010-13 and so on) in terms of average annual productivity results, and in the top two performers across the NEM in 4 out of 5 of these periods.

We have not been provided a reasonable opportunity to review the benchmarking report, its implications and the impact of modelling a longer period of time on the results. We contend that the AER has utilised benchmarking in its capex decision in a manner contrary to that specified by the NER and the intent of the AEMC.

This is a critical natural justice failing as the report has been relied on in the AER's reasons to reject our capex forecast. The practical effect of not meeting its requirements has been the significant error in its decision making based on flaws that could have been identified to the AER had it published the report on time.

Expenditure Forecast Assessment Guideline

In its draft decision the AER state:

> *"For Endeavour Energy, our framework and approach paper (published in January 2014) stated that we would apply the guideline, including the assessment techniques outlined in it. We may depart from our Guideline approach and if we do so, need to explain why. In this determination we have not departed from the approach set out in our Guideline."*[121]

As outlined in Huegin's report at Attachment 1.01, we contend the AER has departed from the guideline in its benchmarking analysis. At a high level, the AER has relied on benchmarking analysis that does not meet the guidelines 6 principles (taken from the Australian Productivity Commission's benchmarking review) for a valid benchmark.

Additionally, the AER has been selective in its use of models/variables and has not conducted its analysis in accordance with the approach specified in the guideline. For instance, the AER has elected not to include DEA as specified by the guideline without providing a sufficient explanation or justification for this departure. Instead, a brief explanation is provided by Economic Insights:

[121] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 14

> *"DEA involves the use of linear programming methods to construct a piece-wise linear frontier over the sample data and then measure efficiency scores. DEA has the advantage that it is non–parametric, and hence does not require the specification of a functional form for the frontier or a distributional form for the inefficiency effects. However, it has the disadvantage that it is deterministic in nature and hence the efficiency scores obtained can be quite sensitive to the effects of random factors and data errors. Hence we have chosen to not use DEA in this study."*[122]

We question whether it is appropriate for a consultant of the AER to make this decision, noting it is the responsibility of the AER to form its own view.

There are advantages and disadvantages/limitations of every method available to the AER. In developing the guideline the AER undertook significant consultation and work in reviewing the available methods. The AER obviously satisfied itself as to the plausibility of DEA as it was included in the guideline.

Without transparency and proper explanation this dismissal of DEA appears subjective and questionable. In several other instances throughout the benchmarking report the AER present incomplete analysis with disclaimers. Ideally, any incomplete or flawed measure would not be presented, which would extend to more than the DEA. However, if the AER is going to present analysis with limitations then all measures should be presented with full disclosure of their various limitations.

Unreasonable decision

As outlined in the previous section, the AER's draft decision for capex has relied on numerical errors of fact which have led to an incorrect conclusion that has impacted the making of its decision. In addition to the issues outlined above we consider the following features of the AER's draft decision making unreasonable:

- **Disproportionate weight on evidence such as benchmarking** – setting aside the procedural issues outlined above, we consider the AER have placed undue weight on the benchmarking factor at the expense of detailed, rigorous analysis. The benchmarking analysis for capex relies on a flawed asset cost proxy (the RAB) and draws inappropriate conclusions based on simple measures such as capex per customer against customer density. These measures are not understood nor are the operating and environment differences and data limitations properly accounted for. We consider benchmarking is only of a limited value at this stage to assist in directing more detailed assessment.
- **Lack of rigour and depth in AER's draft decision making** – The AER has not properly engaged with the granular evidence in our proposals and has rather relied on high level analysis that does not account for our drivers and circumstances. The AER should have undertaken an assessment with a view to identifying whether the cost was efficient and prudent with reference to our obligations and circumstances.

In reviewing the AER's approach Jacobs made the following observations in relation to the AER's lack of understanding of our proposal:

> *"In Jacobs' view it appears that that AER has overlooked the following in reaching its finding that the NSW DNSPs have applied a bottom-up assessment but not a top-down assessment:*
>
> *The iterative top-down assessments between NNSW and the NSW DNSPs; and*
>
> *The development of baseline Capex forecasts for specific expenditure elements using a top-down approach."*[123]

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[122] Economic Insights, Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs, 17 November 2014, page 7

[123] Ibid. 118, p 13.

> *"..the AER has formed an overall opinion on the risk-averseness of the Capex programmes based on the review of isolated elements of the process rather than consideration of the Capex programme risk assessment and prioritisation process in its entirety"*[124]
>
> *".. Jacobs considers the AER's position of largely discounting the bottom-up assessments is ill-founded and appears to demonstrate a poor understanding of a prudently constructed Capex forecast. It is Jacobs' view that such an approach, particularly one taken without due consideration given to risk profiles, could be potentially negligent."*[125]
>
> *"The AER has also concluded that the risk assessments do not adequately justify the priority and timing of the Capex forecasts. However, it appears that this conclusion has been reached because the CASH/PIP process was not properly understood. In Jacobs' view the CASH/PIP top down assessment clearly provides adequate granularity to inform the prioritisation and scheduling of the associated capital works programmes."*[126]
>
> *"..if the AER considers the replacement lives advised by the DNSPs to be incorrect it would be more reasonable to state more appropriate replacement lives (adjusted for environmental factors such as coastal / inland etc.) rather than a poorly substantiated calibration technique that produces observable anomalies."*[127]

- **Logical errors** – The AER rely on assumptions and views that are illogical. For instance, the AER consider that existing assets with spare capacity can service areas without assessing whether such a solution is technically and logistically possible or economically feasible. Furthermore, the AER also cap the percentage of capitalised overheads which can be allocated to capex ignoring the AER approved CAM. Additionally, the AER suggest a key shortcoming of our proposal is a lack of top down analysis when its consultant EMCa, in assessing repex, suggested an over reliance by Endeavour Energy on top down analysis. Also, in the annual benchmarking report the AER note there are unaccounted for factors that cannot be accounted for until all DNSPs are assessed against each of their peers but this assessment has somehow been made for NSW/ACT in spite of this.

In contrast to the AER's view, Jacobs noted:

> *"In Jacobs view it appears contradictory to initially state that "applying a top down assessment is a critical part of the process [which] indicates that some level of overall restraint has been brought to bear", and to then cite that "the process used within [the NSW DNSPs] was inadequate" because the top-down assessment 'brought restraints to bear' in the order of 15 to 24%."*[128]

- **Reliance on consultants** – The AER have relied on consultant reports without properly forming their own view on the issues raised. For augex, WorleyParsons recommend a 10-20% reduction to augex based on limited analysis. Only 6 pages of the report pertain to Endeavour Energy. Despite this the AER consider the recommendation valid and select the midpoint to reduce augex by 15%.
- **Not undertaken a review of the impact of its substitute allowance in terms of risks to safety and reliability outcomes** – This is a key aspect of the unreasonableness of the AER's draft decision. The substitute forecast has not been reviewed by the AER or its consultants against the capex objectives, criteria and factors. Whilst general statements are made in the draft decision there is no demonstration of how the AER has satisfied itself that the substitute forecast better achieves the NEO and capex objective and criteria. The safety and reliability implications of the draft decision are unknown despite reductions being made to specific programs and capex drivers.

[124] Ibid. 118, p 18.

[125] Ibid. 118, p. 23.

[126] Ibid. 118, p. 24.

[127] Ibid. 118, p. 42.

[128] Ibid. 118, p24.

Jacobs stated:

> *"based on our review we consider that the AER has not duly regarded the associated risk profiles. In Jacobs' view the expenditure and risk profiles of the NSW DNSPs are directly linked. Thus, it would appear imprudent to reach a position on expenditure without considering risk profiles. From our understanding of the NSW DNSP's risk profiles gained throughout the course of this review we consider that, if imposed, the AER's Draft Determinations could potentially lead to a situation where the businesses are unable to effectively mitigate the risks associated with their network assets. Critically, in our review of the AER's discussions supporting the Draft Determination expenditure reductions we were unable to observe robust consideration of critical risk factors such as bushfires and public safety; where, in Jacobs' opinion the overarching thread focuses on costs versus reliability of supply."*[129]

In light of the procedural issues detailed in this section, we consider there is only a limited scope for Endeavour Energy to revise our regulatory proposal. The flawed approach relied on by the AER has impacted the credibility and validity of their findings.

5.4.3 Issues raised in the AER's draft decision

In the previous sections we have outlined the numerical errors and procedural issues with the AER's draft decision. In this section we seek to address the substantive matters raised in the AER's draft decision. Generally, we do not consider the AER has raised valid issues that require such significant alterations to our initial proposal. The AER's draft decision does not reflect the revenue and pricing principles in the NEL, particularly, the substitute capex amount does not provide a reasonable opportunity to recover our efficient costs. As such, Endeavour Energy has only made minor revisions to the capex in the initial proposal.

In its assessment of the capex forecast the AER, as per the expenditure forecast assessment guideline, is required to utilise a combination of top down and bottom up modelling of efficient expenditure. In accordance with the guideline, we provided information on the timing, scope, scale and level of expenditure to demonstrate the need for our expenditure and the efficiency of it. The objective being to ensure that:

> *"the overall forecast expenditure will result in the lowest sustainable cost (in present value terms) to meet the legal obligations of the DNSP."*[130]

Our consideration of the issues raised from the AER's top down and bottom up methods is contained in the sections below.

[129] Ibid. 118, p50.

[130] AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, page 24

AER's top down analysis

The AER has utilised a number of top down measures in assessing our capex. Our position is broadly as follows:

- *benchmarking is not of sufficient validity, accuracy or reliability to be relied upon;*
- *our original and revised plans do and will reflect latest demand forecast;*
- *our plans already factor in existing capacity in an optimal manner;*
- *our plans already reflect the flexibility afforded by the changes to our licence conditions; and*
- *our governance and risk management framework is robust and fit for purpose.*

In its draft decision, the AER considered that our capital program did not represent an efficient level of expenditure or reflect the network condition, declining demand and consumption and reduced licence conditions. The AER also considered that our risk management framework is inadequate and that a higher degree of risk could be tolerated whilst meeting our obligations as a DNSP to operate and maintain a safe, secure and reliable supply of electricity. The AER formed this view based on benchmarking data, modelling and consultant advice.

We do not accept the AER's reasons to reject our capital program and therefore have not revised our capex forecast in response to these matters. Our position is based on the following key contentions:

- The AER has relied on benchmarking analysis that contains errors and which does not meet the Australian Productivity Commission's criteria for a valid benchmark as well as modelling which contains errors.
- The AER has formed an unreasonable view regarding the changes and trends in capex that is unacceptable in its consideration of our historical performance and current organisational, network and environmental factors.
- The AER has not adequately considered the information we have provided to support the investment needs underpinning our proposed program, its efficiency and our governance and risk management framework.
- The AER has relied on unreasonable views on the impact of forecasting inputs such as demand, consumption and licence conditions rather than having regard to the detailed evidence provided with our proposal.

Benchmarking analysis

The AER's assessment of our capex consisted of high level benchmarking analysis and more targeted benchmarking as part of detailed analysis. The benchmarking analysis relied on what was published in its annual benchmarking report on 30 November 2014. As outlined in the previous section, the AER has utilised benchmarking in their assessment of our proposed capex despite breaching the requirements under 6.5.7(e) and 6.27(d) of the NER.

Despite these procedural issues, we have sought to undertake a review of the AER's benchmarking analysis. Our key contention is that the analysis contains significant errors that limit its effectiveness as a tool to review the efficiency of our base year. For this reason, we consider the AER should have placed a very limited weight on that benchmarking analysis.

We are of the view that capex is even less suited to benchmarking than opex given its non-recurrent and/or lumpy nature. The AER's benchmarking analysis has not demonstrated how significant differences in network design, characteristics, environment and circumstances have been accounted for. The detailed engineering analysis we have provided to support our proposed capex should receive considerably more weight than such a high level, error prone tool.

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This reiterates the evidence we submitted in our initial proposal, where we demonstrated that high level tools such as multi-factor productivity and partial productivity did not meet the key principles for a 'valid' benchmark as defined by the Australian Productivity Commission.

As part of this revised proposal, we engaged Huegin Consulting and Frontier Economics, Professor David Newbury and Pacific Economics Group (PEG) to undertake reviews of the AER's benchmarking report. These consultants are experts in benchmarking, with significant knowledge and experience in applying such tools. Huegin's report is at Attachment 1.01, with the key conclusions being:

- The analysis used by the AER contained data quality issues, and therefore the accuracy and reliability of the data could not be relied on.
- The AER's analysis was not able to take into account legitimate reasons for differences in costs. In particular, the cost differential between distributors could be explained by reference to the greater number of sub-transmission assets owned by these entities. This means that the explanatory power of the model is limited by its inability to identify if observed differences stem from inefficiency or inherent differences between DNSPs.
- The line of best fit has a very low 'r square' (0.32) which means that from a statistical viewpoint, the relationship is insignificant. Further, there are a number of other statistical errors such as heterogeneity.
- The AER could have used a number of different model specifications to derive different outcomes. Indeed had the AER used its initial specification it would have found an entirely different ranking of DNSPs.

Based on this evidence we consider that the benchmarking analysis is unreliable and accordingly that it would be unreasonable for the AER to apply significant weight to that analysis when forming its view on the efficiency of the forecast. Our views draws on expert evidence we have attached to our proposal including:

- Huegin Consulting: Response to Draft Decision on behalf of Networks NSW and ActewAGL - Technical response to the application of benchmarking by the AER (Attachment 1.02)
- Frontier Economics: Review of AER's econometric models and their application in the draft determinations for Networks NSW (Attachment 1.03)
- Advisian: Review of AER Benchmarking (Attachment 1.04)
- PWC: Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons (Attachment 1.05)
- David Newbery (Cambridge Economic Policy Associates): Expert report (Attachment 1.06)
- Pacific Economic Group: Statistical benchmarking for NSW Distributors (Attachment 1.07)

Capital trends and changes

Our proposed capital program was 43% lower than the allowance for the 2009-14 period. This reduction reflected the achievement of mandatory licence conditions during 2009-14, reduced forecast demand growth, an improvement in the network condition and delivery efficiencies. Whilst capex is not recurrent in nature it is influenced by factors such as these over time. We are of the view that our proposed program reasonably reflected the changes in both our network and operating environment since the submission of our last regulatory proposal.

In rejecting our proposed capex the AER has relied on a number of assessment techniques, including a high level assessment of the changes and trends in our proposed capex. Similar to the benchmarking analysis described above, the AER has formed the view that our overall capital program does not reasonably reflect the capex criteria and is therefore not prudent or efficient.

Specifically, the AER has determined that a larger reduction to capex from the 2009-14 period is warranted based on the following factors:

Endeavour Energy

- network capacity due to low utilisation and reducing demand; and
- removal of Schedule 1 of the Licence Conditions

Based on the evidence we have provided to the AER in support of our capex we believe the AER has formed an unreasonable expectation. This is explained in more detail below.

Peak demand and utilisation

In our initial proposal we provided demand forecasts and explained the impact of these forecasts on our capital program. Unlike the 2009-14 period, demand growth was not a major driver of investment at a global level. Rather, our reduced 2014-19 proposed capex is driven by the need to augment the network at a local level to cater for significant greenfield development and spatial demand growth.

In response to AER questions Endeavour Energy provided updated demand forecasts which were marginally lower than those submitted with our initial proposal . We also explained the reasons for differences between the AEMO forecast and our forecast.

The AER has formed the view that reducing peak demand and the utilisation of existing assets warrants a reduction to the proposed capex.

> *"Nonetheless, Endeavour Energy undertook significant investment in its network in the 2009–2014 regulatory control period, resulting in a significant reduction in asset utilisation in its network. This suggests there is some excess capacity in the network that remains to be more efficiently utilised, ahead of additional augmentation investment…..*
>
> *….Fourth, Endeavour Energy's proposed expenditure to meet growing demand in new developments is likely to be overstated. This is because there is excess capacity in existing network adjacent to the new development areas, and there is some uncertainty about whether all of the new suburbs will be ready for development within the 2014–2019 period. We have not made an explicit adjustment to the augex forecast to account for the overstated pockets of growth proposal. However, we consider that it lends further support to our 15 per cent reduction to the augex forecast (as outlined above)."*[131]

and

> *"This is because Endeavour Energy will not need to augment those substations it does not expect to grow and this lower demand forecast will furthermore reduce the network utilisation."*[132]

We accept that there is capacity available in the substations named by the AER and a fundamental part of our strategy for servicing the initial stages of development in each precinct is to utilise this capacity by running 11kV feeders back to these substations where appropriate. While these distances are technically acceptable for a lightly loaded rural network, when the load density increases to that typical of an urban network, the voltage regulation experienced at the end of a feeder quickly becomes unacceptable and the establishment of additional feeders becomes necessary. At this stage it becomes more cost effective to establish a supply point central to the new load in the form of a new zone substation.

In relation to servicing of initial stages of development Jacobs report noted:

> *"..we consider it reasonable to assume for the purposes of forecasting expenditure at the distribution wide level, that the relationship between cost and demand (i.e. $/kVA) tends toward a linear relationship.*

[131] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 33

[132] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, pages 39-40

> *However, in cases where augmentation expenditure is driven by step changes of base infrastructure, as is required for new developments, the application of a linear relationship will misrepresent the cost of constructing the assets required. In these cases, the Augex will be substantially higher than the forecast demand growth (i.e. a large capex requirement for a relatively small demand) as a base level of infrastructure does not exist."*[133]

The timing of investments in our proposal has been optimised given forecast growth rates. As such, we have not revised our regulatory proposal to address these matters as use of this capacity where it is technically and economically viable is already included in our augex proposal see Attachment 5.02 to this proposal for further detail.

Licence conditions

As previously noted, we consider our capital program has been substantively reduced compared to the 2009-14 period. A contributing factor to this was achieving compliance with the licence conditions as at 30 June 2014. The AER believes the removal of the Schedule 1 licence conditions warrants a greater reduction in capex for the 2014-19 period.

> *"We consider that the change in licence conditions is likely one of the key reasons for the reduction in capex proposed by Endeavour Energy for the 2014–2019 period. However, it has not reduced to the levels that existed prior to the licence conditions being introduced. Given the recent changes in licence conditions, we consider the period prior to 2005 should be the benchmark for assessing the level of capex for the 2009–2014 regulatory control period."*[134]

The AER does not provide any evidence to demonstrate why this is a reasonable view. The Licence Conditions were introduced as a result of concern over a general degradation of service levels across the industry. The expenditure in the previous regulatory period was necessary to build up the capacity in the network to a level where one failure did not put large areas of the network at risk. Lower network utilisation was an expected and desired outcome from the introduction of supply security standards.

Based on clear feedback we have received from customers to maintain current service levels we have not revised our proposal to adopt a level of capex similar to pre 2005. By prescribing cuts to capex that drive the use of the additional capacity that has been installed, the AER is essentially prescribing a repeat of history in future periods.

Setting this issue aside, we have advised the AER clearly in our regulatory proposal and supporting information that it is the achievement of the licence conditions at 30 June 2014 that drives the reduced capex rather than the removal of some conditions as at 1 July 2014. The licence conditions codified good planning practices and primarily imposed a cost on Endeavour Energy by specifying a timeline by which to achieve compliance.

The removal of some of these conditions does not mean that we will not manage our network in a substantively different manner. Rather, it simply provides us increased discretion as to the timing and planning of the required investment. Only if we were substantively non-compliant at the end of the 2009-14 period would the removal of certain licence conditions materially alleviate investment needs in 2014-19.

Governance and risk management framework

The AER is of the view that our governance, prioritisation process and risk management framework are inadequate based on consultant advice and industry comparisons. The AER considers that reductions could be achieved in the timing, scope, scale and level of expenditure if we use less conservative forecasting methods:

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[133] Ibid. 118, p26.

[134] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 28

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> *"In the course of our review of Endeavour Energy's proposal we have determined that Endeavour Energy's risk management practices are overly risk averse and result in higher capex forecasts than necessary."*[135]

and

> *"Endeavour Energy's forecasting methodology applies a bottom-up assessment but not a top-down assessment. We consider a top down assessment critical in deriving a total forecast capex allowance that reasonably reflects the capex criteria. We also find that Endeavour Energy's forecasting methodology incorporates an overly conservative risk assessment which does not adequately justify the timing and priority of its proposed forecast capex."*[136]

Forecasting methodology

Firstly, we consider that we use both top down and bottom up methods in developing our capex forecast. The AER's view directly contradicts that expressed by the AER's own consultant EMCa, who state:

> *"At the project/program level, we found that Endeavour takes a conservative approach to applying risk assessment criteria. We also found that, at the portfolio level, decision support methods reflect a high level assessment.*[137]
>
> *….This position appears to be primarily based on its weighted average remaining life calculation. Endeavour also uses its Value Development Algorithm (VDA) to cross-check its expenditure level."*[138]

In our proposal we outlined our use of the AER's repex and augex models, VDA, WARL, probabilistic planning, the planning process for greenfield expenditure in particular and the common Network NSW prioritisation of the program. All of these represent top down tools utilised by Endeavour Energy to assess the overall level of capex. The largest single component of our forecast – repex has been well tested by these tools and techniques identified above and confirmed by the AER's repex model. This approach complements a bottom up method which examines in detail:

- safety, environment and regulatory requirements;
- asset condition;
- forecast demand and development activity;
- asset utilisation;
- suitability of the assets for their function;
- present demand on the asset;
- historical demand placed on the asset over its service life;
- maintenance and service history;
- knowledge of equipment type faults;
- the unique risk relating to those assets; and
- pre-defined criteria that form the basis of asset health index and trigger a flag for asset refurbishment and replacement (for major equipment groups).

It is not clear how the AER has engaged with our proposal if it has failed to understand our approach. It is notable that the AER and its consultants spent less than two days with us engaging on our initial proposal for capex.

[135] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 10

[136] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 50

[137] EMCa, Review of Proposed Replacement Capex in Endeavour Energy's Regulatory Proposal 2014-19, October 2014, page iii

[138] EMCa, Review of Proposed Replacement Capex in Endeavour Energy's Regulatory Proposal 2014-19, October 2014, page ii

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Governance framework

Our governance and risk management framework was explained in our initial proposal to the AER and the accompanying evidence. We have a prudent and robust process in place to ensure that our capex program represents a reasonable estimate of the lowest cost solution to address a genuine network need. We have not revised our framework and therefore capex forecast to address this matter as we do not consider evidence has been provided to demonstrate an overestimation bias or overly conservative position.

The key stages of our governance process, as outlined to the AER and its consultant, include:

- Governance around the policies and standards which drive key triggers for investment with both independent and peer review and endorsement of the technical and risk triggers for investments.
- Effective input early in the process with the provision of long term (forward 5 to 10 years) strategies and plans to the Board.
- Annual development by the business and approval of the risk prioritised investment portfolio by the Board (Gate 1). Effective risk based prioritisation enables the Board to make an informed decision based on its risk appetite with an understanding of the risk versus expenditure position rather than uninformed changes to the portfolio.
- Preliminary individual project/program approval outlining the need and the options to address it (Gate 2). Approval is by the delegated authority and all projects and programs with a total estimated investment above $5 million are subject to independent and peer review as part of the governance process. The review tests the need for the investment and the prudency of the proposed options.
- When project design is complete, and the most efficient delivery model has been determined, final project approval is required (Gate 3). As with the preliminary approval all investments above $5 million are tested through an independent and peer review prior to approval.
- Ongoing reporting and monitoring of projects against time and budget at Executive and Board level.
- Detailed delegations and internal audit of approval processes.
- Post implementation reviews of completed projects to pick up and reiterate any lessons learned to allow for future process improvement.

In response to AER information requests we responded to several questions from the AER and its consultant. These responses demonstrated the prudency of our investment governance and included:

- Charters of our relevant committees;
- Relevant company policies and procedures;
- Business cases;
- Gate 1, 2 and 3 approval examples;
- Change management process and procedures;
- Change controls and examples;
- Post completion project review examples; and
- Networks NSW combined delivery reports.

Risk Based Prioritisation

Risk based investment prioritisation is one of the key stages (Gate 1) in our governance process. The ability to prioritise investments is an important factor in development of the portfolio investment plan. The methodology we have use for prioritisation needs to be consistent, efficient and transparent in order to articulate the risk outcome associated with a prioritisation scenario.

Our capex forecast was built from the bottom up with the lowest cost solutions to address identified network needs. These required investments were then prioritised on a risk basis. The current risk topic areas used to prioritise the portfolio include:

- Public safety, environmental or regulatory impact;
- Network initiated fire;
- WH&S (employee);
- Network condition;
- Community impact (reputation);[139]
- Network reliability; and
- Network capacity.

Delivery risks and constraints are also reviewed and where required incorporated into the plan and sensitivity and economic analysis is conducted with consideration to the viability of the capital structure under a number of scenarios.

The investment governance committee reviews the resulting portfolio and provides a top down challenge process. This process tests the projects and programs, both for consistency of risk prioritisation and for deferral risk.

The Board considers the risk based portfolio, including a number of projects and programs at selected constraints point, when determining an appropriate investment risk appetite. The Board is appropriately informed of both the prioritisation process and the risk outcomes resulting from deferring expenditure.

The Board did not, as indicated by EMCa, reduce the forecast expenditure due to an overestimation bias or due to the lack of an internal challenge process. Rather the reduced portfolio reflected to the Board's informed decision to move to a less conservative risk position through deferring some of the lower risk projects and programs.

We recognise that the factors driving investments and risk can change over time – for example due to changes in demand, failure modes, asset deterioration, delivery costs, standards and policies. As a result a formal change control process is in place to provide governance and transparency for any changes to the Board approved portfolio and risk position. The Board is provided with a report on changes to the approved portfolio each quarter.

Subsequent to the submission of our regulatory proposal we had an independent review conducted into our risk based prioritisation process. Evans and Peck, who conducted the review, noted that there were a number of very significant positive aspects to our process and also provided a number of improvement opportunities. With the exception of one recommendation, to extend the process to go beyond the risk score and explicitly consider value assessment, all improvements have been incorporated into the capex forecast supporting the revised proposal. The recommendation not yet implemented is under consideration for the next version. While the changes implemented have improved the process they have not resulted in a material change to the risk position adopted by the Board. Similarly, it is not expected that the recommendation not yet implemented will result in a material change to the risk position adopted by the Board.

In Jacobs' opinion:

> *"…the risk assessments used in the development of the bottom up programme appear to be broadly consistent with AS/NZS ISO 31000:2009 Risk management Principles and guidelines. The risk assessment process appears to have been applied methodically across the projects and programmes in the capital forecast."*[140]

In response to AER information requests we responded to several questions from the AER and its consultant. These responses demonstrated the prudency of our prioritisation process and included:

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[139] Reputation is a new topic area included as a result of an independent review into our prioritisation process and tool. This topic has been included in the prioritisation process used for the capex forecast in this revised proposal.

[140] Ibid 47, p2

- The prioritised risk master list that underpinned the capex forecast in the regulatory proposal;
- Documentation describing the prioritisation model, including the topic areas, questions and definitions of the weighting values;
- A sample of project summary data sheets drawn from specified risk ranges; and
- A copy of the Evans and Peck review of the risk based prioritisation process.

Advisian (formerly Evans and Peck) has subsequently conducted a post implementation review of the changes implemented to the prioritisation process and have confirmed that the changes provide for significantly increased alignment with the common risk matrix, greater differentiation on risk scores, improved focus on top risks at Board level and a greater level of documentation and reasoning behind risk scoring. A copy of the post implementation review is provided at Attachment 5.07.

Ultimately, we consider that we are best placed when it comes to understanding risk and our network. Our management are fully cognisant of our obligations and our asset management practices have been developed to ensure that we meet these obligations. Based on the information we have provided, we believe the AER have imposed a level of risk that is unacceptable, detrimental to customers interests and based on a limited understanding of our network and asset management practices. As such, we have not revised our proposal to reduce the scope of our capital program in light of the AER's perceived governance and forecasting bias.

Review by capex category

In addition to a top down review of the overall capex the AER examined disaggregated capex by driver. In forming a view as to whether the total forecast capex reasonably reflects the capex criteria the guideline requires that the AER examine the volumes and costs applicable to drivers of capex. In acknowledgement of the complex nature of capex, but in apparent contradiction of the approach applied by the AER to benchmarking the purpose of this is to enable the AER to:

> *".. identify and scrutinise different operating, legal and environmental factors that affect the amount of cost of works performed by DNSPs, and how these factors may change over time."*[141]

In addition to this, the AER's guideline outlines the assessment approach specific to each driver of capex. The drivers being:

- Replacement;
- Augmentation;
- Connection and customer driven works; and
- Non-network capex.[142]

We consider that sufficient information was provided to enable this assessment and demonstrate that each category reasonably reflected the capex criteria.

In our initial proposal, we outlined the reasons for our capex by driver and provided evidence for each of these programs. Unlike opex, capex can be lumpy in nature and driven by an array of complex factors, obligations and needs. As such, grouping capex by standardised categories can allow a more detailed assessment of projects underpinned by common engineering and technical analysis.

As discussed in earlier sections, the AER has rejected our proposed capex based on a combination of top down and bottom up analysis of the overall program and its subcategories. The AER considered the disaggregated capex by driver and projects within these programs did not reflect the prudent and efficient level of expenditure based on their assessment and consultant advice.

[141] AER, Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, page 25

[142] This is known internally as non-system capex

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In considering whether to revise our regulatory proposal we examined the AER's process and the substance of the matters raised by the AER. As identified in the sections above, we contend that the AER did not properly consider the information we provided to demonstrate that our costs were efficient and prudent. In particular, we note the following statement from the Tribunal during the 2009-14 determination process:

> *"… it is not the AER's role to simply make a decision it considers best. It is also correct for it to say that the AER should be very slow to reject a DNSP's proposal backed by detailed, relevant independent expert advice because the AER, on an uninformed basis, takes a different view. Nor, may the AER reject such a proposal merely because it has an expert opinion. The AER, based upon any expert advice, needs to make its own evaluation, an evaluation that is reviewable by this Tribunal."*[143]

In the following sections we review the AER's draft decision regarding each category of capex and consider whether the matters raised by the AER require revision.

Augmentation capex

The AER has reduced augex (excluding overheads) by 17.4%. In addition to the numerical and process issues identified earlier our response is as follows:

- *our forecast should reflect the latest demand forecast, as such we have revised the HV and LV development programs;*
- *existing utilisation rates and changes to our licence conditions do not warrant further reductions as our plans consider them; and*
- *we do not consider a 15% reduction is appropriate based on the AER's engineering advice as our planning approach already utilises probabilistic planning and cost-benefit analysis.*

In our initial proposal we forecast $429.3 million ($2013-14) of augex, including connection capex for the 2014-19 period. This expenditure was designed to service significant growth in our greenfield development areas; North-West and South-West Sydney. Therefore, our proposed program was driven by localised growth as opposed to organic, global demand growth that has historically driven augex. The supporting attachments to our regulatory proposal provided further detail as to our growth servicing strategy and the key business cases related to our augex program.

In its assessment the AER has focused on the demand forecast, network utilisation and consultant advice. The AER has removed connections capex to a discrete category and allocated a portion of our RIN balancing item to arrive at an adjusted "proposed" augex of $426.1 million ($2013-14). The AER has then rejected this figure and substituted an amount of $351.8 million ($2013-14) excluding overheads, a reduction of 17.4% according to the AER. The breakdown and the key reasons provided by the AER in making this reduction are as follows:

- *"reduced Endeavour Energy's augex forecast by approximately 2.86 per cent to account for updated spatial demand forecasts provided by Endeavour Energy during the determination process*
- *applied a further 15 per cent reduction in light of independent engineering advice that suggests Endeavour Energy's forecast augex did not take account efficiencies that could be achieved*

[143] Australian Competition Tribunal, Application by EnergyAustralia and Others [2009] ACompT 8 File No2 of 2009, page 64

- *through risk based cost benefit analysis assessment techniques in the context of the revisions to its licence conditions.*

These reductions take into account the observed trend in augex that shows that there is excess capacity in Endeavour Energy's network that remains to be more efficiently utilised."[144]

In forming this view the AER's assessment approach was outlined as follows:

- *"trend analysis, comparing the proposed augex with historic expenditure levels, taking into account changes in demand, network capacity and design and planning standards to assess whether the forecast is within a reasonable range to allow Endeavour Energy to meet expected demand, and comply with relevant regulatory obligations*
- *an engineering review undertaken by WorleyParsons of Endeavour Energy's forecasting processes and methodology to assess whether Endeavour Energy's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives*
- *the augex model to generate trends in asset utilisation, to assess Endeavour Energy's need for network augmentation (as noted below, this was only used to a limited extent in this assessment)."*[145]

At a fundamental level it appears the AER has relied on a misconception that our proposed augex is driven by global peak demand. In regards to each of the key points raised by the AER and their assessment approach refer to Attachment 5.02 to this revised proposal for a detailed response. To summarise, our position on each of these issues is as follows:

- the AER's trend analysis appears to be a mixture of benchmarking and consideration of macro factors such as licence conditions and capacity utilisation. Endeavour Energy developed a forecast utilising a bottom up method which accounted for our operating environment and obligations. We tested our program against top down measures such as the AER's augex model. This analysis confirmed the prudency of our forecast which was well below that indicated by the top down model;
- whilst asset utilisation has declined we consider existing assets cannot adequately service the greenfield areas and localised growth we are seeking to address on a large scale. No technical review has been conducted by the AER to validate the legitimacy and practicality of their contention that existing capacity can adequately service greenfield growth;
- minor changes to the global peak demand forecast do have consequential impact on our proposed augex program, specifically the HV Development program. However, greenfield development is not impacted by global peak demand and more generally follows the same parameters as network conncetions capex, which was accepted by the AER in the draft determination;
- changes to the licence conditions do not warrant further reductions as we already utilise a probabilistic planning approach for augex. This is evidenced by the greenfield business cases we provided in support of our initial proposal (Attachment 5.25 to that proposal) and the reductions in augex made prior to submission of proposals (as addressed by responses to AER data requests (reference AER Endeavour 005);
- similar to the above point, we do not consider the 15% reduction applied by the AER based on the 10-20% range provided by WorleyParsons to be reasonable. This is because we have incorporated program efficiencies into our forecast. In developing our revised forecast we have incorporated further efficiencies based on more rigorous options analysis compared to an arbitrary 15% reduction; and

[144] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 51

[145] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, pages 32-33

- a technical review or assessment of the substitute forecast against the capex factors and criteria has not occurred. The consequences of the substitute forecast have not been considered nor has it been demonstrated that this forecast represents an efficient and prudent forecast to meet our obligations as a DNSP.

For these reasons, Endeavour Energy has not revised its proposal to adopt the AER's draft decision on augex as we do not consider it will contribute to the achievement of the capex objectives. Instead, in light of the AER's draft decision we reviewed our augex forecast to ensure it reflected the efficient cost of servicing demand growth and to reflect the latest available information. As such, we have reduced the direct costs of our proposed program by 14%, specifically in the areas of HV and LV development. These revisions are discussed in more detail later in this chapter and in Attachment 5.02 to this proposal.

Additionally, the AER requested that the revised proposal provide an updated demand forecast and consider the new VCR value determined by AEMO. We have provided the AER our latest summer demand forecast in response to information request 035, and have incorporated this forecast into our revised augmentation proposal where appropriate. The next winter demand forecast is yet to be finalised however no investment was proposed on the basis of our previous winter forecast and this is not expected to change when the next forecast is produced.

In regards to the VCR, we note that this concept has limited usefulness when servicing greenfield development. In these areas it is necessary to invest to provide infrastructure to enable the first loads to be connected. The “lumpy” nature of the investment required to achieve this means that the value attributed by these first customers is never going to be greater than the cost to establish that initial infrastructure.

Having said that, we note that the AEMO residential VCR figure is higher than the residential figure from either the 2007 Victorian study or the more recent NSW study undertaken by the AEMC in 2011. Our customer base primarily consists of residential and industrial customers, the VCR value for these groups have both increased. In particularly, the greenfield development areas primarily consist of residential customers. It would be inappropriate to simply rely on the NEM or NSW weighting which consists of DNSPs with significantly different customer bases to Endeavour Energy. We consider the residential and industrial VCR results would justify earlier or increased investment over that considered using the earlier VCR figures. However, we have not sought to increase our augex forecast in this revised proposal on this basis.

Replacement capex

The AER has reduced our repex by 10.7% or 35.2% (excluding overheads). In addition to the numerical and process issues identified earlier our response is as follows:

- *we have not revised our proposal to reflect the 2001-2019 cost average as this is an overly simplistic and flawed measure that fails to consider the network consequences of the regulatory enforced under-investment of the early 2000s;*
- *the AER's engineering review contains errors, is unreasonable and does not represent a technical assessment of our proposal; and*
- *the SCADA "step change" that we have proposed, however we have sought to revise this program based on the latest available information.*

The AER considers our plans and management decisions are not based on a sufficient knowledge of the network condition and need. In its draft determination the AER has rejected Endeavour Energy's proposed repex forecast of $922.8 million ($2013-14) and substituted an amount $661.1 million ($2013-14) excluding overheads. The breakdown and the key reasons provided by the AER in making this reduction are as follows:

- *"Endeavour Energy's proposed repex is around 55 per cent higher than its long term average and Endeavour compares unfavourably on a number of benchmarks which take into account Endeavour Energy's network size.*

- *An engineering review carried out by EMCa found that there are systemic issues with Endeavour Energy's forecast that mean its proposal is likely to overstate the amount of repex required to meet the capex objectives. Endeavour Energy is likely to be replacing many assets earlier than is necessary to meet the capex objectives.*

- *There is evidence from an engineering review that there are systemic issues with Endeavour Energy's forecast that mean its proposal is likely to overstate the amount of repex required to meet the capex objectives. Endeavour Energy is likely to be replacing many assets earlier than is necessary to meet the capex objectives.*

- *Our predictive modelling is consistent with Endeavour Energy's proposal for the six asset groups that were modelled. However, for categories that were not included in predictive modelling we were not satisfied that Endeavour Energy's forecast was prudent and efficient and estimated a prudent and efficient substitute that was sufficient to meet the capex criteria."*[146]

In forming this view it is unclear what weighting was assigned to these issues. It appears the AER's assessment primarily relied on repex modelling which confirmed our forecast (for those asset groups modelled). For the remaining repex it appears the balancing item has not been assessed (but rejected entirely) and the unmodelled repex was reduced primarily on the basis of a step change to the 'SCADA' category. Despite this, several issues are raised by the AER within its draft decision regarding our repex.

In regards to each of the key points raised by the AER and their assessment approach refer to Attachment 5.03 to this revised proposal for a detailed response. For the asset groups assessed utilising the repex model we accept this approach and the AER's findings. Whilst it is not clear what weighting was assigned to analysis and issues raised within the AER's draft decision outside of the repex model in forming their view, our response to these issues is as follows:

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[146] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 50

- the benchmarking measures do not account for the significant number of operating and environment factors that may impact the results. Furthermore, the data relied upon is not comparable or prepared on a similar basis across the DNSPs included nor is the dataset of a sufficient size to form reliable conclusions. In spite of this, the AER assumes it is measuring efficiency despite the apparent low explanatory power of the variables modelled and unquantified, unknown number of unaccounted for factors;
- the long term average repex covers the 2001-2019 period to support an asset age profile the AER considers reasonable between the 2006-13 period. This mismatch is illogical, the AER should match the cost average to the age profile the AER considers acceptable. The long term cost average covers a significant period of under-investment (2001-2006) prior to substantive industry changes (licence conditions). Irrespective of this, there is no consideration or demonstration of why the long term average is a valid benchmark and measure;
- the long term average is a simple measure that is significantly less refined than our top down VDA analysis. Its use is contrary to the AER's and EMCa's questioning of whether one of the key outputs of this analysis, the WARL is even a suitable proxy for both asset condition and risk;
- we consider the EMCa report does not constitute a technical review of our proposal or even a reasonable one. The findings are based on numerous factual and logical errors, unreasonable views and high level analysis that is not supported by evidence. We do not consider it is of sufficient quality, competency or accuracy to be relied upon by the AER in making its determination; and
- a technical review or assessment of the substitute forecast against the capex factors and criteria has not been conducted by the AER to understand the safety, reliability and long term implications of the AER's draft decision. The consequences of the substitute forecast has not been considered nor has it been demonstrated that this forecast represents and efficient and prudent forecast to meet our obligations as a DNSP.

SCADA

As noted above, for the 'unmodelled' repex categories the AER's reduction primarily relates to the AER's rejection of a step change to the SCADA category. The AER and EMCa have classified SCADA, protection, communications and pilot cables as "SCADA".

The most material increase in this area is in pilot cables, the AER did not accept this "step change" based on the following finding from EMCa:

> *"In the absence of more substantial justification than that provided in the documentation available to us (i.e., the SARP description), we are not convinced that such a step change in expenditure has been adequately justified.*
>
> *For pilot cables, we would expect to see a full business case to support an investment step change of this magnitude."*[147]

This information was not requested by EMCa or the AER, however it was readily available and is provided as Attachment 5.06 to this revised proposal. The analysis provided in this business case clearly demonstrate the need for this program and its legitimacy.

At this level of granularity in asset classes there will always be step changes in expenditure when a new expenditure program is commenced. In this case, Endeavour Energy recognised that the condition of the pilot cables as an asset group had deteriorated to a level where they posed an unacceptable risk to the safe and reliable operation of the network, as evidenced by failures such as described below, and initiated a replacement program in accordance with the attached business case. The step change in expenditure in this

[147] EMCa, Review of Proposed Replacement Capex in Endeavour Energy's Regulatory Proposal 2014-19, October 2014, page 26

case is particularly pronounced because, while functionally related, pilot cables are a fundamentally different asset to SCADA and protection equipment with a significantly higher replacement cost.

To summarise the information contained in our attachments, several of our pilot cables have already failed leading to compromised protection resulting in increased outages, fires, damage to equipment and costly repair. As an example, on 6 August 2014 a feeder burnt down due to slower temporary protection installed as a result of the failed pilot cable. This incident resulted in a loss of 33kV feeder 491, loss of 11kV feeder, lines down in multiple locations, lines fell across the western railway line causing five hour closure of the railway line disrupting 220 train services and started two grass fires.

There is also a step change in renewal of SCADA assets for replacing aged remote terminal units (RTUs). These devices are typically no longer supported by suppliers and are experiencing high failure rates (72% of RTUs greater than ten years in age have had a failure of some component in the last five years). Endeavour Energy will run out of spare parts for these devices in 2015 at the current rate. These assets also rely on integrated batteries to retain their information, batteries which are now beyond their life.

These RTUs are critical not only to the monitoring and control of the network, but also directly control the load control which provides hot water to customers, medical emergency functionality for Endeavour Energy employees, voltage regulation which maintains voltage within the prescribed limits and reclose and change-over schemes which maintains reliability. These devices are also used to configure the network to manage bushfire risk on high bushfire risk days. Again, there is a business case available to support these replacements, see Attachment 5.06 to this revised proposal.

There is also a step change in protection replacement due to two reasons:

- Firstly, the devices have a 10-15 year life (10 year design life) and have not been replaced in prior years due to being installed from 1999 and hence are now a step change. We have proposed to start replacing these in 2016-17 at an age of 17 years - 70% after their design life.
- Secondly, there is a need to upgrade the older protection relays on Endeavour Energy's distribution feeders. The primary reason is to reduce arc flash for the safety of the public and Endeavour Energy employees. Endeavour Energy considers that programs such as this which enable us to maintain technical currency are vital for ensuring that our network continues to meet the needs of its customers. Again there is a business case for this program see Attachment 5.06 to this revised proposal.

In summary, the issues identified in this section are in addition to the numerical and procedural issues outlined earlier in this chapter. As such, we have not revised our regulatory proposal to adopt the AER's total substitute repex. Instead, we have revised our direct repex forecast (excluding overheads) as follows:

- reject the $519 million substituted by the AER for the repex modelled asset groups and instead submit our original forecast of $515 million;
- reject the unmodelled repex substitute amount of $117 million (for substation major projects and miscellaneous expenditure, various distribution substations and switching stations) and instead submit a revised forecast of $72.4 million that reflects the removal of duplicated expenditure that was previously included in the balancing item;
- reject the AER's substitute SCADA forecast of $25 million and instead submit a revised forecast of $61.5 million; and
- include in the revised forecast an amount of $7.3 million for the purchase of essential spares, an amount that was previously included in the balancing item.

We note that according to our modelling the repex model suggests a forecast of $93 million over the regulatory period for SCADA. Therefore, while the repex output supports a higher expenditure our revised SCADA proposal reflects the detailed, bottom up understanding of asset condition. These revisions are discussed in more detail later in this chapter and within Attachment 5.03 to this revised proposal.

Reliability

The AER has reduced our reliability expenditure by 100%. In addition to the numerical and process issues identified earlier our response is as follows:

- *we will provide evidence with this proposal which outlines the portion of the program related to Schedule 3 licence conditions;*
- *our historical and forecast expenditure clearly seeks to maintain reliability performance and we should be provided an allowance to do so as the STPIS is intended to fund improvements and therefore generates no revenue if performance is maintained; and*
- *we have revised our program downward by 22.1% to ensure it reflects the minimum cost necessary to maintain performance.*

In our initial proposal we proposed reliability capex forecast of $65.3 million ($2013-14). This investment is to ensure compliance with reliability performance targets set out in jurisdictional licence conditions, in particular the worst performing parts of our network. The program also sought to maintain our reliability performance in light of the STPIS and customer feedback which indicated a preference for existing service levels.

In its draft decision the AER has rejected the entire reliability program for the following reasons:

- *"A review of Endeavour Energy's supporting information does not indicate the amount and the basis for this amount that has been proposed to address any compliance issues related to the Schedule 3 licence conditions (i.e. individual feeders performance obligations).*
- *It appears that the proposed amount includes expenditure to avoid penalties under the STPIS; and*
- *The amount proposed has not been allocated in such a way that enables us to identify whether this amount already forms part of our analysis of other capex driver categories (e.g. we may have taken into account compliance related repex as part of our consideration of repex)."*[148]

In regards to the first point raised above the AER did not raise this matter with Endeavour Energy or seek clarification prior to the release of its draft decision. This information was readily available as in developing the forecast our workings identified the portion of the program relating to Schedule 3 compliance. As part of this revised proposal we have submitted this information to verify the Schedule 3 component of the proposed program, see Attachments 5.04 and 5.05 to this proposal.

For the remaining expenditure the AER considers that an allowance should not be provided for expenditure designed to avoid penalties under the STPIS. It appears the AER have misconstrued the intent of the STPIS and applied an overly cautious approach to avoid Endeavour Energy receiving reward payments under the scheme. If the AER is concerned about this occurring then it may not be appropriate to apply the STPIS scheme until further customer research is conducted.

Irrespective of this, we contend that this position is inconsistent with the capex objectives, criteria and factors. As per 6.5.7(a) of the NER a capex forecast should, amongst other objectives, seek to the extent that there is no applicable regulatory obligation or requirement in relation to:

(iii) maintain the quality, reliability and security of supply of standard control services; and
(iv) maintain the reliability and security of the distribution system through the supply of standard control services;

[148] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 66

The AER's approach does not allow Endeavour Energy to maintain reliability at current levels as we cannot fund investment through avoided cost. We agree that the STPIS should fund overall reliability improvements which are separate to regulatory obligations. However, our proposal sought to maintain the current service levels consistent with regulatory obligations which will deteriorate in the absence of the proposed investment.

In their analysis of the reliability impacts if the AER's draft decision was to be adopted (Attachment 1.14), Jacobs expressed the view that:

> *"Specific cuts to reliability capex will prejudice NNSW's ability to meet Schedule 2, 3 and 5 of licence conditions even if not making a large impact on STPIS. Reduction of programmes targeting poorly performing feeders will have a direct negative impact on supply reliability. However, due to the small proportion of these programs within the overall capital program and also due to the focus of these programs on individual poorly performing feeders, rather than overall system reliability, the STPIS will not generate savings or penalties equivalent to the cost of the works. Therefore, these programs must be funded in addition to any STPIS benefits/penalty."*[149]

In regards to the AER's final point we contend that sufficient detail was provided to the AER to enable this assessment. Our regulatory proposal provided our capex forecast by driver (which included reliability) and by PTRM asset class. As outlined in earlier sections, the AER has not engaged with our regulatory proposal but rather, relied on RIN data.

The RIN did not provide for a reliability category, instead the reliability expenditure was allocated to the balancing item in the RIN as we considered it did not satisfy any of the AER's other definitions.

In light of these points we have not revised our reliability forecast in this proposal to reflect the AER's substitute amount. We do not consider it appropriate to reject the entire program without seeking clarification from Endeavour Energy on the Schedule 3 expenditure, properly considering the intent of the STPIS or relying on assumptions regarding the RIN data provided.

Instead, we have reviewed the proposed program to carefully consider the minimum expenditure required to maintain reliability performance in light of the 2009-14 investment which has been completed since the submission of our initial regulatory proposal. As such, we have reduced our proposed program by 52% to $24.4 million (excluding overheads). This is discussed in more detail later in this chapter and in Attachment 5.04 to this revised proposal.

We note Attachment 5.04 to this proposal also provides further evidence that our strategy is to maintain (at best) rather than improve performance. Our analysis suggests stable or slightly worsening trends in reliability over the 2014-19 period based on the expenditure program we proposed and analysis of SAIDI and poor performing feeders.

[149] Jacobs, Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment, January 2015, p9

Capitalised overheads

In our initial proposal our capex forecast contained $308.5 million ($2013-14) of capitalised overheads. The AER has separately assessed these overheads and rejected our forecast substituting an amount of $145.3 million. This amount is based on a capped allocation rate 12.99% based on the average actual capitalised overheads to total gross system capex over the 2009-14 period. We have not revised our regulatory proposal for this approach as we consider it contravenes Australian Accounting Standards and the AER approved CAM.

> *The AER has capped our capitalised overheads at 13%, effectively reducing our capitalised overheads by 53%. In addition to the error identified earlier in calculating the 13% our response is as follows:*
> - *this approach is inconsistent with and in breach of Australian Accounting Standards and the AER approval in May 2014 of our Cost Allocation Method; and*
> - *the AER have not assessed our overhead costs but instead benchmarked overheads in the opex decision and capped capitalised overheads; and*
> - *this analysis provides no basis for a 53% reduction to our capitalised overheads.*

Australian Accounting Standards

Australian Accounting Standard AASB 116 *Property, Plant and Equipment* states that:

> *"the cost of an asset should comprise any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management."*

Whilst our financial systems automatically link direct costs to capital projects such as direct labour and materials, other indirect costs exist which are not automatically linked to a project for capitalisation. To ensure Endeavour Energy complies with this Australian Accounting Standard, Company Policy 6.9 *Capital Expenditure Overhead Calculation* (Attachment 6.05 to our initial proposal) provides a methodology for how to capitalise our indirect costs.

This Policy states that an overhead pool is determined based on an analysis of activities undertaken, and the nature of costs incurred, at a granular organisational level. A capitalisation rate is then determined by reference to the direct labour expenditure of the network divisions, split between maintenance and capital. The capitalisation rate is then applied to the overhead pool to determine the amount of eligible overhead expenditure to be capitalised.

Our proposed capitalised overheads in our proposal were calculated in accordance with this methodology. However in the AER draft decision the proposed allowance for capitalised overheads has been calculated using an average rate of 13% of capitalised overheads to total capex. This proposal circumvents Australian Accounting Standard AASB 116 *Property, Plant and Equipment* as using a fixed percentage does not provide any basis to support how that amount is directly attributable to the creation of a system asset.

Since Endeavour Energy is bound by Australian Accounting Standards and will need to continue using its existing methodology for the calculation of capitalised overheads, this will inevitably result in Endeavour Energy needing to make further cuts to our direct capital programs beyond what the AER has already proposed to ensure we do not exceed the allowance for capitalised overheads, thereby assuming greater safety and reliability risks.

AER Approved Cost Allocation Method (CAM)

In addition to the above, we submitted an early iteration of our proposed CAM to the AER on 24 September 2013. This was assessed by the AER, resulting in the AER providing feedback and relatively minor changes to permit the CAM's approval, with our revised proposed CAM submitted on 29 November 2013. In May 2014 the AER decision on our proposed CAM was as follows:

5 CAPITAL EXPENDITURE

"We consider the CAM proposed by Endeavour Energy gives effect to and is consistent with our guidelines and the rules. We therefore approve, under clause 6.15.4(c) of the rules, Endeavour Energy's proposed CAM."[150]

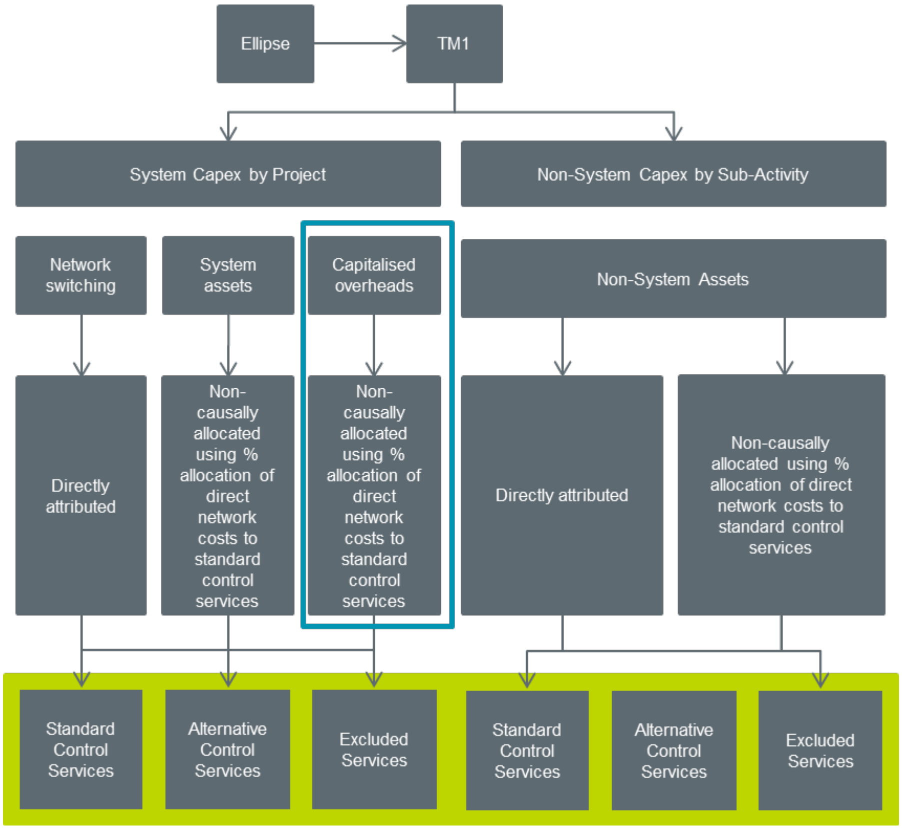
The approved application of our CAM is what we have used in our proposal, we have not sought to change the method employed at arriving at our capex forecasts.

Our approved CAM notes for system capex:

"all capex projects are allocated directly except Network Switching and Capitalised Overheads – both are allocated on a pro rata basis, where costs are allocated on a pro rata basis, based on the direct allocation of System Capex."[151]

Figure 5c below, an extract from our approved CAM, outlines the high level process of capex allocation:

Figure 5c: High-level process of capital expenditure allocation



Our approved CAM outlines that our capitalised overheads are non-causally allocated using the value of system capex directly attributed to standard control services, alternative control services and unregulated services. This allocation method has been adopted as there is a nexus between the value of projects and the amount of capitalised overheads that the suite of projects would require.

The AER's approach contravenes the approved CAM and assumes overheads are purely variable costs. Any reductions to overheads must be made by assessing the costs within this category rather than arbitrarily

[150] AER, Final Decision: Endeavour Energy Revised Cost Allocation Method, May 2014, page 13

[151] Endeavour Energy, Cost Allocation Method, November 2013, page 16

applying a capped allocation percentage. In regards to this we note that the AER examined network, corporate and total overheads allocated to both capex and opex in its detailed opex decision (Attachment 7 to the AER decision). The benchmarking analysis utilised appear to indicate that Endeavour Energy's overheads are comparable to other DNSPs:

> *"Essential Energy and Endeavour Energy however, appear to have network overhead costs that are comparable to service providers with similar densities."*[152]

Further, if a linear relationship was assumed for the partial productivity indicator measures presented it appears Endeavour Energy would reside on or ahead of the "frontier". Whilst we do not support this analysis it forms the extent of the AER's assessment of overheads and there appears to be no basis for a 52.9% reduction to our capitalised overheads. In addition to this, the AER has not considered the interrelationship between capex and opex. That being the consequential outcomes on opex if an artificial cap is applied to what portion of overheads can be capitalised. In the absence of this consideration, Endeavour Energy has not been provided an opportunity to recover efficient costs.

Balancing item

The AER has allocated the RIN balancing item to repex, augex and connections and made various reductions. Our response is as follows:

- *this item primarily consisted of capital contributions which should have been removed prior to allocation;*
- *the expenditure within the balancing item has not been assessed, rather varying reductions have been made based on the category it was allocated to; and*
- *to enable an assessment of this expenditure we have sought to explain which category each item relates to and its purpose and need.*

In its draft decision the AER has assessed our proposed capex by RIN category. As these categories did not completely align to that of our proposal there was a balancing item of $432 million. The AER has removed reliability capex from this item and apportioned the remaining $422 million to the augex, connections and repex categories.

As discussed earlier in this chapter there are numerical errors in the AER's approach such as the failure to remove the capital contributions from the balancing item. In regards to the AER's assessment it appears, for repex at least, that the AER has not assessed the balancing item allocated to the RIN categories. Our understanding is as follows:

- the balancing item allocated to connections has been accepted;
- the balancing item allocated to augex has been reduced by 15%; and
- the balancing item allocated to repex has been rejected entirely.

In regards to repex, we are of this view because the AER's assessment relates to the $740 million allocated to this category in the RIN. The substitute forecast is $661 million irrespective of whether the pre or post balancing item is referred to. For augex, we consider the reduction is 15% as the remainder of the augex reduction was specific.

As outlined earlier, we consider the capital contributions amount should be removed from the balancing item and the AER's allocation of it. For the remaining $66 million, assuming the reductions are equally apportioned across each item, it appears the AER have approved a substitute forecast of $19.5 million a reduction of 70.5%: This assumes:

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[152] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 7: Operating expenditure, November 2014, page 80

- a 100% reduction to the $44.0 million attributable to repex given the AER's approach outlined above;
- acceptance of the $4.7 million allocated to connections;
- a 15% reduction to the $17.4 million allocated to augex.

We have not revised our regulatory proposal as we do not consider these reductions verifiable or reasonable. The balancing item primarily consists of a number of expenses, we outline these categories and the reasons why we consider them important below:

- **Infrastructure land** – This is expenditure on acquiring land for the purposes of construction of zone substations to service greenfield development. When developable land is held by multiple small land owners, the most equitable way for zone substation land to be provided is for Endeavour Energy to acquire the land at an undeveloped market price. Endeavour Energy may also make strategic land acquisitions ahead of the time it is required if a specific location is required for network configuration purposes. In these cases Endeavour Energy will acquire the land at undeveloped rates in preference to waiting until the land has started to be developed and is only available at developed rates. Our proposal included $5.7 million for land acquisition over the period. We have reviewed this figure in light of the latest information on land development in the greenfield areas and believe that it is appropriate. This amount has been included in our augex in this revised proposal.
- **Switching** – this is generally included in capitalised overheads as it supports several areas of expenditure.
- **Essential spares** – This is expenditure on maintaining a stock of essential spares items that are critical to the operation of the network and are not readily available in the event of a failure. This should be considered as repex as expenditure is required to replace items from the essential spares stock after an equipment failure. Our proposal included an amount of $7.3 million for the period and is based on historic rates of expenditure, which we believe to be still appropriate. This amount has been included in our repex in this revised proposal.
- **Asset relocation** – Generally the relocation of Endeavour Energy assets to allow for activities such as land development or road widening is funded by the proponent. In certain situations Endeavour Energy has identified a need for an augmented asset to meet an identified or forecast network constraint. In these cases we will fund the cost difference between a like for like replacement and the augmented cost. Our forecast of $4.3 million is based on historical volumes of this work, which we believe continue to provide a reasonable basis for our forecast in this category. This amount has been included in our augex in this revised proposal.

In our revised proposal we have allocated these items into the categories where we believe that they best fit, to leave a balancing item that consists of other system capex that we do not believe is adequately described by any of the other major categories. This category totals $27.9 million (inclusive of overheads) and relates to new network monitoring and control equipment.

Non-network capex

The AER has reduced our non-network capex by 7.4% to reflect reduced labour requirements, our response is as follows:

- *based on the labour reductions we have made we consider this reduction of 7.4% is appropriate; and*
- *our revised proposal reflects therefore reflects this reduction.*

In our initial proposal we proposed a non-network capex forecast of $176.4 million ($2013-14). This investment is to support the operation of the network to safely and reliably deliver our network investment. This expenditure relates to IT, land and buildings, furniture, fittings, plant and equipment and land and buildings.

5 CAPITAL EXPENDITURE

In its draft decision the AER has rejected our proposed forecast and substituted a forecast of $163.3 million ($2013-14) a reduction of 7.4%. This reduction relates to buildings and property and plant and equipment. For buildings and property the AER state:

> *"we do not consider that Endeavour Energy's 2010 FSC strategy supports the need, timing or costs of the proposed projects given the significant changes in Endeavour Energy's operating environment since that time as set out in the May 2014 update.*
>
> *…. Therefore, on the basis of the information presently available to us, we consider that Endeavour Energy's forecast of $38.6 million ($2013–14) for buildings and property capex excluding the Mulgrave and Guildford FSC projects is likely to reflect efficient and prudent expenditure."*[153]

And for plant and equipment the AER state:

> *"We consider that forecast capex of $16.1 million ($2013–14) reasonably reflects the required expenditure. This represents a reduction of 25 per cent from Endeavour Energy's actual capex in the 2009–2014 regulatory control period and is in line with the forecast reduction in employee numbers. We will make an allowance for it in our estimate of total capex for the 2014–2019 period."*[154]

Based on the labour reductions we have achieved over the 2009-14 period and the further reductions targeted in our revised forecast we consider these reductions appropriate. As such, we have revised our proposal to reflect the AER's position. The revised proposal section below provides the revised non-network capex forecast.

Demand management

The AER has accepted the application of Part A of the DMIA and requested feedback on whether a reduction is required to system capex to reflect expected demand management deferrals. Our response is as follows:

- *the AER has quoted an incorrect figure significantly understating our 2009-14 deferrals;*
- *it is unreasonable to expect deferrals equal to Ausgrid (or our own) over the 2009-14 period to be achieved in the 2014-19 period as our environment has changed; and*
- *it is not appropriate to make any reduction to system capex, particularly without providing for additional opex.*

Demand management is employed as an alternative to network options such as augmenting the network where this is more efficient to do so. In assessing Endeavour Energy's proposal the AER have decided to continue to apply Part A of the DMIA. Consistent with the F&A the AER have decided that Part B of the scheme, the d-factor, will no longer continue except for the remaining lagged adjustments from its application over the 2009-14 period.

Additionally, in its draft decision the AER note that it considered making an explicit adjustment to the system capex forecast on the basis of the demand management deferrals from the 2009-14 period. Specifically:

> *"We have considered whether it is appropriate for us to determine an explicit amount of capex that could be deferred through demand management, based on the scale and positive outcomes achieved by Ausgrid during 2009–14 and the Productivity Commission report. Using this approach we could apply an explicit systems capex forecast offset for Endeavour of 9.2%, or approximately $93 million ($2013–14)."*[155]

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[153] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 70

[154] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 72

[155] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 76

In relation to this issue the AER invite further submissions. In regards to this matter we do not consider it appropriate to revise our forecasting approach to introduce an explicit demand management driven reduction to system capex as contemplated by the AER. The AER's rationale in raising this concept is as follows:

> *"Our analysis suggests that the Endeavour Energy's estimate of $34 million significantly understates the amount of capex that could be deferred. By comparison, analysis of Ausgrid's demand management activities in the 2009–14 period found that it was able to achieve a deferral of $334 million or 9.2% of its system capex portfolio based on an $8 million investment."*[156]

Firstly, we note that the figures quoted by the AER are incorrect. As per Attachment 5.34 to our initial proposal and the Annual RINs we deferred $184 million of system capex via demand management over the 2009-14 period rather than the $34 million quoted by the AER. When this is considered as a percentage of our total system capex, including the amount invested in compliance with licence conditions, our deferral over the 2009-14 period was 9.68%. Further detail on the outcomes of our demand management programs can be found in Attachment 5.02.

Irrespective of this we do not consider this a reasonable position. Similar reductions to the 2009-14 period cannot be prescribed for the 2014-19 period. The circumstances have changed, in particular reductions to demand and augex primarily relating to greenfield growth means that demand management alternatives will not be as readily available or viable.

Furthermore, additional opex above that allowed under the DMIA would be required to fund such aggressive targets. Our demand management strategy included as an attachment to our initial proposal showed the activities we intended to undertake over the 2014-19 period. It does not appear the AER has considered this program. We contend that the AER can either allow demand management capex, which can be deferred using demand management opex, or to simply approve the opex itself to carry out such activities. It is not reasonable to expect us to meet network needs through the use of non-network alternatives and reduce the capex accordingly without providing an allowance for opex to implement demand management initiatives.

Also the RIT-D process may introduce substantial delays to the planning process that will inhibit our ability to implement demand management options. Whilst the scheme is designed to promote demand management it does not provide for speedy implementation of a demand management solution when a network alternative above the trigger threshold exists.

For these reasons we contend it is inappropriate to mandate a level of demand management without considering the feasibility of this. We consider it more appropriate to rely on the DMIA and incentives in place for DNSPs to utilise demand management where appropriate.

[156] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 74

5.5. Our revised proposal

In the section above we have sought to assess the specific issues raised by the AER in its draft decision and whether revisions are required in response. For the reasons outlined above we generally do not consider the AER's analysis and findings are valid or reasonable. However, we have sought to revise our proposal to include any reductions we consider the AER have reasonably identified. Furthermore, setting aside the detail of the AER's capex decision, at its core the AER considers that its alternate forecast reflects the capex criteria rather than our proposed forecast:

> *"We are not satisfied that Endeavour Energy's total forecast capex reasonably reflects the capex criteria. We compared Endeavour Energy's capex forecast to a capex forecast we constructed using the approach and techniques outlined above. Endeavour Energy's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria."*[157]

We therefore also reviewed our proposed program and the latest available information to assess whether further revisions were required. As a DNSP, Endeavour Energy is better placed than the AER to understand the efficient and prudent level of investment required to maintain the quality, safety, reliability and security of our electricity network. It appears that the AER's substitute forecast is primarily driven by reductions to the capital program which we do not agree with given the associated safety and reliability risks.

Instead, after careful consideration we consider the following revisions to our proposed program are appropriate:

- a reduction to the HV and LV development augex programs of $45.5 million based on changes to forecast demand and further program and delivery efficiencies identified by the AER;
- a decrease of $46.5 million to our SCADA program based on our latest available information on asset condition;
- a decrease of $26.6 million to our reliability program based on our latest available information on asset condition and network performance; and
- a decrease of $13.1 million to our non-system capex based on changes identified by the AER.

Additionally, we considered whether further productivity efficiencies could be sourced to deliver the revised program at a lower cost to customers. Further, we have set stretch targets to more aggressively pursue blended delivery and realise the savings from Networks NSW joint procurement activities. These savings represent a further reduction to the known reductions outlined above.

In total we have reduced our initial proposed capex of $1,746.0 million ($2013-14) by 9.7% to $1,576.3 million. We consider this revised proposal clearly demonstrates that our forecast is a reasonable estimate of the costs involved in satisfying the capex objectives, criteria and factors. In addition to these revisions we have also revised our capital contributions forecast to $402.5 million ($2013-14) to reflect the latest available information, specifically the 2013-14 Annual RIN data which showed an increase in capital contributions due to a significant increase in development.

Earlier in this chapter we outlined our revised capex by the categories included in our initial proposal for comparative purposes. To support the AER's assessment of our capex, the table below contains the same program allocated to the Reset RIN categories, exclusive of capital contributions, for comparison.

[157] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure, November 2014, page 16

Table 5.5: Revised forecast capital expenditure over the 2014-19 regulatory period

$m; Real 13-14	Forecast year ending 30 June					
	2015	2016	2017	2018	2019	Total
Augmentation	92.3	52.8	42.6	53.7	37.9	**279.3**
Replacement	171.5	166.1	123.4	100.7	94.6	**656.2**
Connections	14.6	15.4	15.3	15.4	15.6	**76.2**
Reliability	4.6	4.7	4.9	5.1	5.2	**24.4**
Balancing Item: (other system capex)	**0.5**	**3.0**	**3.5**	**3.5**	**9.7**	**20.2**
Load control relays	0.4	0.4	0.4	0.4	0.4	2.0
Technology efficiency	-	2.4	2.9	2.9	9.1	17.4
Power Quality monitoring	0.1	0.2	0.1	0.1	0.1	0.8
Capitalised Overheads	78.6	68.1	68.4	70.1	71.0	**356.3**
Non-system	49.0	27.3	28.6	28.6	30.1	**163.6**
Total	**411.1**	**337.5**	**286.6**	**277.0**	**264.1**	**1,576.3**

Note: numbers may not add due to rounding

In addition to the points above, Endeavour Energy's revised forecast also reflects updated real labour escalators which utilise the AER's real labour escalators contained in its draft determination. Additionally, as requested by the AER in its draft determination, the table below outlines the labour cost escalators used and the amount of real labour escalation within our revised capex forecast:

Table 5.6: Revised forecast capital expenditure over the 2014-19 regulatory period

$m; Real 13-14	Forecast year ending 30 June					
	2015	2016	2017	2018	2019	Total
AER real labour escalators	0.0%	0.9%	1.2%	1.5%	1.4%	**-**
Revised capex labour escalation	0.0	2.7	4.7	6.6	8.4	**22.3**

Also, whilst we do not consider capitalised overheads should be assessed separately to the direct costs they are allocated to, we understand this is the AER's preferred assessment approach. To enable this in the absence of a revised Reset RIN, the table below outlined the overheads allocated to the capex by driver in Table 5.4.

Table 5.7: Capitalised overheads for the 2014-19 regulatory period

$m; Real 13-14	Forecast year ending 30 June					
Capitalised Overheads by driver	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Growth	30.5	20.5	20.4	26.3	19.7	**117.4**
Asset renewal/replacement	45.4	44.2	43.9	40.0	44.8	**218.2**
Reliability	2.2	2.4	2.5	2.7	3.0	**12.9**
Compliance	-	-	-	-	-	**-**
Other system assets	0.4	1.1	1.6	1.1	3.5	**7.8**
Total	**78.6**	**68.1**	**68.4**	**70.1**	**71.0**	**356.3**

Why our revised proposal better satisfies the capex objectives and criteria

We do not consider the revised forecast capex is materially different from that proposed originally by Endeavour Energy except to the extent that it targets more ambitious and larger productivity savings. As such, the reasons outlined in section 1.2 “Our initial proposal” as to why we consider our forecast satisfies the capex objectives, criteria and factors remain valid. As outlined in that section, Attachment 0.03 to our initial proposal and the ‘meeting the Rules’ section of our initial proposal provide further detail as to why we consider this to be the case.

Our forecast is developed using a combination of top down and bottom up forecasting techniques relying on our significant experience, technical expertise and network information. The AER’s method to derive the substitute was to rely on a combination of modelling, benchmarking analysis and consultant advice.

We have fundamental concerns with the AER’s substitution method. Under the Rules, the AER is open to apply any method it wishes to derive a substitute capex. However, its decision must reasonably reflect the capex criteria, be without error, and be reasonable in the circumstances. Our view is that a reasoned decision maker should:

- Examine the obligations of an individual DNSP and identify the areas where inefficiencies arises in the capex proposed by the DNSP. The intent being to identify where the timing, scope, scale and level of expenditure can be varied over time to better manage the driver. This should consider the capex factors in their entirety.
- Identify how the DNSP could transition to these efficiencies and manage their obligations over time in a sustainable manner.

In their System Capex and Maintenance Prudency Report report Jacobs have stated:

> *“While we acknowledge that there can always be improvements made to a system or process, it is Jacobs’ view that the top down assessment being applied to the overall capital programme by Networks NSW in conjunction with the NSW DNSPs better reflects these requirements than the AER’s own top-down assessment.”*
>
> *“With respect to each area of system expenditure reviewed, Jacobs was able to observe apparent flaws in reasoning, poorly substantiated decisions, and an over reliance on speculative views.*
>
> *This was not only evident within the approaches adopted by the AER, but also with respect to the reasoning used to discount the approaches adopted by the NSW DNSPs in preparing their Expenditure Proposals. In cases, Jacobs also found that the approaches used by the NSW DNSPs*

better aligned with the AER's stated criteria for the elements that a robust approach "should" comprise. Overall, Jacobs considers that the approaches used by the NSW DNSPs demonstrated greater rigour than the AER's substituted approaches."[158]

Our original and revised forecasts consider these issues and seek to strike a balance between sustainably reducing costs and maintaining safety and network performance. In contrast, the AER has not turned its mind to the level of risk that we can accept, and efficiencies we can practically achieve in meeting our network obligations. This has led the AER to make unreasonable cuts to forecast capex based on high level analysis and advice that did not consider our existing operations, network condition and future investment need. As we identify below, the analysis used by the AER contains errors and lacks precision.

Further, the AER has not considered what a sustainable level of capex is to satisfy our legal obligations. It has not analysed how we can defer or avoid investment without reducing the quality or safety of our service. Critically, if the AER expects current service standards to be maintained it has not considered how this can be achieved without exceeding the allowance within the 2014-19 period or requiring substantial investment in subsequent periods. We refer the AER to a statement prepared by Group Executive – Network Strategy (Attachment 5.09) which demonstrates that our revised proposal already incorporates a prudent prioritisation process.

The consequence of the AER's draft decision is that it does not provide a sufficient allowance to maintain the current level of services to our customers. The AER suggests that the short term cost should simply be absorbed by the DNSP. However, the magnitude of the cuts being made by the AER and the introduction of the CESS would leave us in a financial situation where we have no other choice but to:

- Take more risks with our operations. Ultimately this may lead to increased probability of safety incidents and deterioration in reliability. Further, there is a long term cost impost from deferring necessary expenditure;
- Create investment bottlenecks in NSW and fail to service customer growth; and
- Reduce the quality of our customer services and safety.

While it is difficult to predict with accuracy the specific impacts of a reduction in repex the weighted average remaining life (WARL) of the asset base, (which takes into account both age and condition factors), provides a useful proxy for expected network, safety and reliability outcomes.

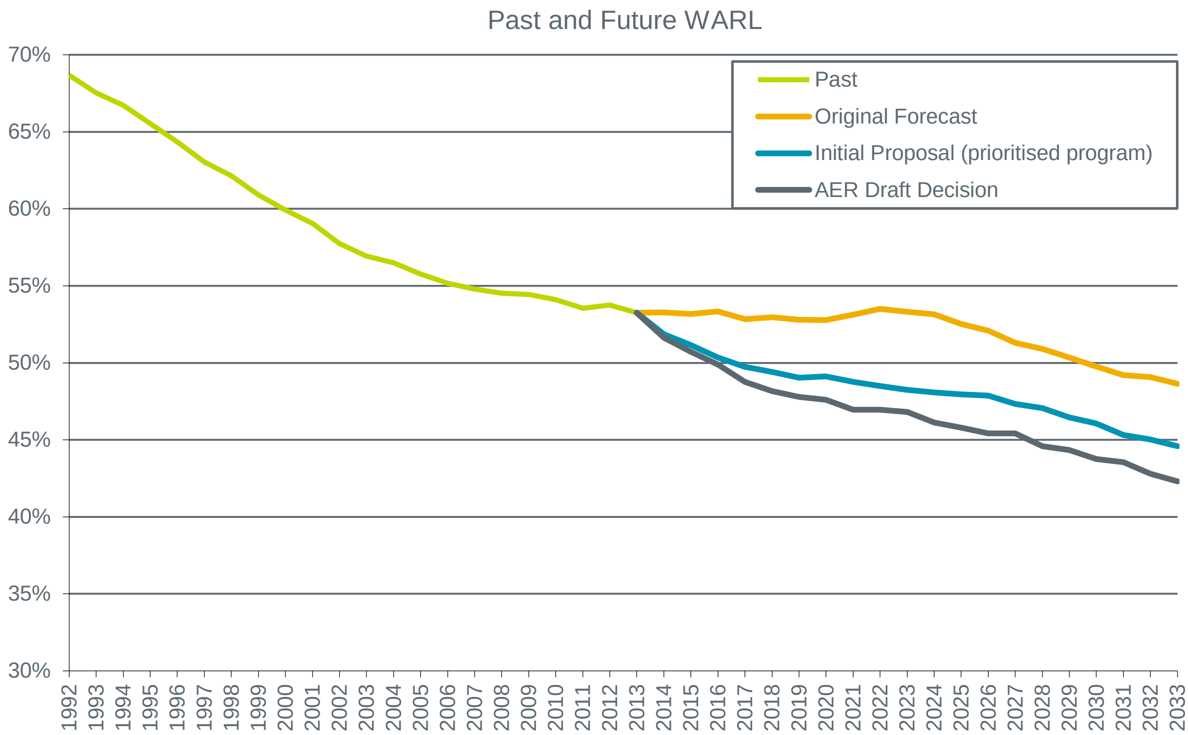
The graph below indicates both the outcome expected from the investment level in our proposal (Initial proposal) as well as the level that Endeavour Energy had previously been targeting (original forecast) before the review of our overall risk position that led to our Board making a 20% reduction in our capex. The third line shows the impact of the AER's 10%[159] cut to our repex, which clearly shows that the AER's reductions will result in a reduction in WARL below the level that Endeavour Energy considers to be sustainable in the long term.

At a high level this indicates that significant catch-up expenditure will once again be required in future regulatory control periods. The short term price reductions will be at the cost of network health as assets age and deteriorate. We expect this declining WARL to be associated with increased maintenance expenditure and likelihood of asset failure and a decline in network performance.

[158] Ibid. 14, p50

[159] This 10% is based on the AER's Draft Decision Attachment 6. A higher repex reduction of 35% is also noted by the AER in its decision however this calculation utilises a higher "proposed" repex figure which includes allocation of the balancing item. As noted in section 5.4.1 we consider the 35% reduction has been calculated in error. We have therefore used the 10% figure as this is verifiable.

Figure 5d: Weighted average remaining life forecast against various scenarios



We do not consider this ‘boom and bust’ regulatory framework is in the long term interests of consumers. It is also contrary to the customer feedback we have received which clearly indicates that customers are not willing to accept reduced service levels in exchange for price reductions.

Additionally, in deriving a substitute amount the AER has not considered the increased opex that would result from the capex reductions. Our original and revised forecast considers the trade-off implications between capex and opex. The AER has not made a consequential adjustment for reductions in capex that would result in necessary increases in opex for maintenance and redundancy costs. Our analysis suggests that the AER’s capex reductions as set out in the draft decision would require a $5 million increase in opex. Our primary position though is that the capex reductions are inappropriate.

Similarly, we consider that the AER’s draft decision to reduce capex and not properly account for capex-opex trade off costs would lead to a reduction in service standards, which would then require an adjustment to the STPIS targets. Instead the AER have set STPIS targets based on improved reliability performance, there is no reasonable basis for these substitute targets as outlined in Attachment 5.04 to this proposal (STPIS attachment). In the context of this section we consider this provides further evidence the AER have not made a reasonable or informed decision when setting a substitute capex forecast.

For the reasons outlined above we contend that our revised forecast represents a more reasonable estimate than the AER’s substitute amount of the efficient costs of meeting the capex objectives and criteria.

6 OPERATING EXPENDITURE

Summary

We are proposing a revised operating expenditure program of $1.4 billion (real 2013-14) for the 2014-19 period to maintain the safety, reliability and security of our distribution system and support our business activities. This is an 6.1% increase on our forecast opex in our initial proposal.

In our initial proposal, we provided the AER with information to demonstrate the efficiency of our forecast opex. Our expenditure sought to address the expectations of our customers by providing safe, reliable and affordable service in the 2014-19 period. A key element of our proposal was to incorporate substantial efficiencies from our cost saving programs.

The AER's draft determination rejected our proposed expenditure and substituted a substantially lower amount. The AER's decision stems from its assessment technique, which involved extensive reliance on benchmarking analysis.

We have considered whether revisions are required to incorporate the matters raised in the AER's decision and its reasons for it. We have retained most elements of our initial proposal rather than revise for the AER's decisions or reasons. In this respect we consider that the AER misconstrued its task under the Rules, and this has not allowed a proper assessment of our proposed opex. Further, we consider that the substantive issues raised by the AER in respect of labour practices, vegetation management, redundancy costs and rate of change have not raised issues that require revision of our proposal.

In reviewing the issues raised by the AER's draft decision, we have also considered the latest information that has become available after submitting our initial proposal. As a consequence we have made the following revisions:

- The AER considered that our vegetation management costs should not be accepted. Upon further review, we found that our costs should be higher than proposed as a result of updated information on our actual market contracted costs in 2013-14, which better reflect the costs of complying with our standards to manage bushfire, public safety and reliability risk. This results in an $110.1 million increase for vegetation management over the regulatory period.
- The AER found that our proposed opex contains material inefficiencies. We have examined the latest data to establish the impact of our efficiency programs in the 2014-19 period. Based on this analysis we have found that our employee productivity rates are higher than we previously forecast in our initial proposal. This results in a labour productivity improvement of 21.6% by the end of the regulatory period.
- We have compared our labour cost escalators to that developed by the AER and have accepted the averaging approach taken by the AER in the draft determination. This results in a $19.8 million reduction.
- We have also reduced our non-labour opex where is directly relates to efficiency improvements, i.e. reduction in the fleet.

Table 6.1 provides our revised forecast opex for each year of the 2014-19 period, compared to the initial proposal and AER draft decision.

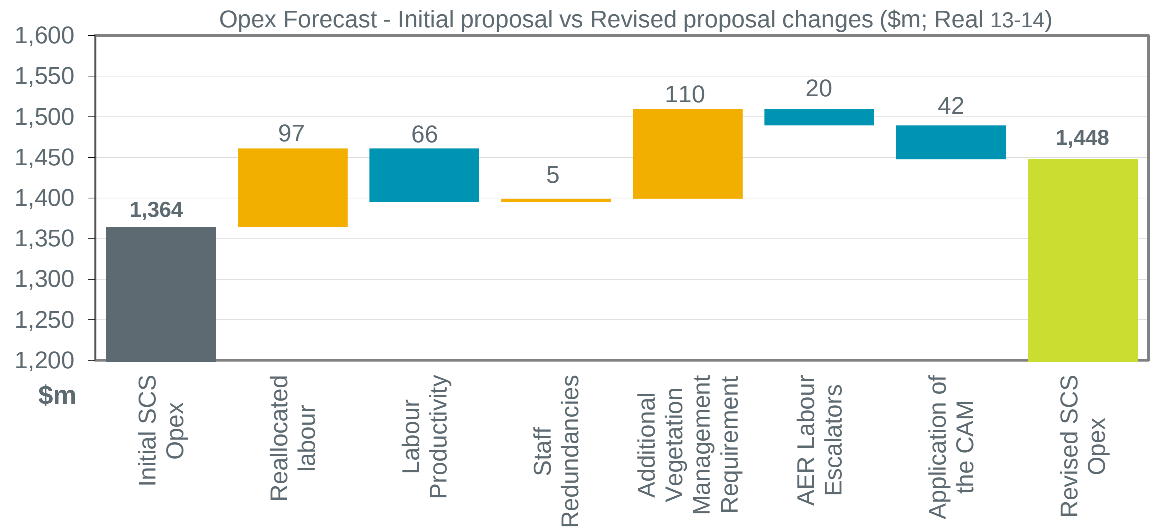
6 OPERATING EXPENDITURE

Table 6.1: Forecast standard control operating expenditure over the 2014-19 regulatory period

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Endeavour Energy's initial proposal	263.7	268.4	277.1	274.6	280.2	**1,364.1**
AER draft determination	203.4	206.4	210.2	214.4	219.0	**1,053.4**
Endeavour Energy's revised proposal	**286.0**	**298.8**	**291.5**	**287.5**	**283.8**	**1,447.6**

The drivers for the 6% real increase between Endeavour Energy's initial proposal and this revised proposal are depicted in Figure 6a. It should be noted that approximately $20 million associated with debt raising costs and Demand Management Innovation Allowance (DMIA) has not been included in Table 6.1 and Figure 6a.

Figure 6a: Changes in Endeavour Energy's operating costs between initial proposal and revised proposal ($m; Real 13-14)



The principal drivers for the change are:

- An increase in vegetation costs to reflect the introduction of LIDAR technology and consistent vegetation cutting standards in NSW to manage bushfire, public safety and reliability risk.
- A change in the allocation of fixed divisional and corporate overheads as a consequence of increased vegetation management expenditure and a reduced capital expenditure program with such changes being in accord with the May 2014 approval by the of the Cost Allocation Model.
- Increase in the business transformation costs from reallocated labour associated with a reduction in the capital program
- Reduced costs as a result of labour productivity improvements.

6 OPERATING EXPENDITURE

We have structured this chapter as follows:

- Section 6.1 sets out the framework in the NER and Law that the AER must apply in making its constituent decision for opex.
- Section 6.2 provides a summary of how our initial proposal addressed the framework, including how our proposed opex was determined so as to achieve opex objectives, and how this satisfies the opex criteria with regard to the factors.
- Section 6.3 provides a summary of the AER's decision including its assessment methods, its reasons for rejection, its basis for substitution and how it sought to address the Rules framework.
- Section 6.4 notes our concerns that the AER misconstrued its task under the framework and this has not enabled it to make a satisfactory assessment of our proposal under the opex criteria. We show that the AER has misinterpreted its powers following amendments to the Rules and Law in 2012. The AER has been misdirected in three ways:

    - The AER adopted its own alternative estimate as a starting point, and used the estimate as a threshold for accepting our proposal. We consider the AER should have undertaken a more in-depth review of our proposal rather than apply an alternative estimate that could not fully acccount for the opex criteria and factors.
    - The AER has placed undue weight on benchmarking analysis in reviewing our proposal and in making its decision to reject and substitute our forecast, in circumstances where the benchmarking analysis that has been conducted should not be relied upon.
    - The AER's substitute allowance has been derived using benchmark information of other DNSPs, and has therefore not considered our activities, drivers or circumstances. We consider that the AER should have undertaken a reasonableness check of its substitute amount by assessing the implications to our operations from its decision.

- Section 6.5 sets out our considerations of whether we should revise our proposal in light of the elements of the proposal that the AER did review. These include labour practices, vegetation management, redundancy payments and rate of change factors. We conclude that the AER has not provided sufficient evidence or analysis to support a revision of our proposal.
- Section 6.6 notes that in reviewing the matters raised in the AER's decision, we have examined whether any revisions are required to incorporate new information or data since submitting the proposal. We set out our revisions to the initial proposal including vegetation management, updates to our efficiency programs based on latest data on employee productivity, and updates to real cost escalators. Finally, we show how our revised proposal better satisfies the opex criteria with relation to the opex objectives, compared to the AER's decision. We undertake a review of our activities and show that the AER's proposed cut would reduce our ability to maintain our network, undertake prudent vegetation management, support our system activities, and deliver on our corporate obligations.

6 OPERATING EXPENDITURE

6.1. Framework for AER's decision on opex

The Rules require the AER to make a number of constituent decisions as part of its distribution determination. Clause 6.12.4 relate to the AER's decisions on the forecast opex proposed by a DNSP in its building block proposal. The AER either:

(i) acting in accordance with clauses 6.5.6(c) accepts the total of the forecast opex for the regulatory control period that is included in the current building block proposal; or

(ii) acting in accordance with clauses 6.5.6(d), does not accept the total of the forecast opex for the regulatory control period that is included in the current building block proposal, in which case the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

In making its decision, the AER is guided by the objectives, criteria and factors in the Rules. In interpreting these requirements the AER should have regard to the overall principles of assessment that have been described by the Rule maker, the AEMC in recent Rule determinations. Each is discussed below.

6.1.1. Objectives criteria and factors

The Rules set out a framework such that Endeavour Energy is required to propose total opex that Endeavour Energy considers is needed to produce the outputs or outcomes that are encapsulated in the Rules. These outputs/outcomes are specified in clause 6.5.6(a) of the Rules and are termed the operating (opex) objectives.

Clause 6.5.6(a) require Endeavour Energy to include in its building block proposal the total forecast opex and capex for the 2014-19 period which Endeavour Energy considers is required to achieve each of the opex objectives.[160]

The AER is required to make a decision on the total forecast opex proposed by Endeavour Energy. The Rules provide that the AER must accept the forecast opex included in Endeavour Energy's building block proposal if the AER is satisfied that the total forecast opex reasonably reflects the expenditure criteria. These expenditure criteria are:

1) the efficient costs of achieving the operating expenditure objectives; and
2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and
3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In deciding whether or not the AER is satisfied that Endeavour Energy's proposed total forecast opex reasonably reflects each of the opex criteria, the AER must have regard to the opex factors.[161]

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[160] These objectives are:(1) meet or manage the expected demand for standard control services over that period; (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services; (3) to the extent that there is no applicable regulatory obligation or requirement in relation to: i.the quality, reliability or security of supply of standard control services; or ii.the reliability or security of the distribution system through the supply of standard control services,to the relevant extent:iii.maintain the quality, reliability and security of supply of standard control services; and iv.maintain the reliability and security of the distribution system through the supply of standard control services; and(4) maintain the safety of the distribution system through the supply of standard control services. (Objective 4)

[161] The first three factors were deleted as part of the 2012 Rule change. The factors in the Rules are therefore as follows:(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; (5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods; (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; (6) the relative prices of operating and capital inputs; (7) the substitution possibilities between operating and capital expenditure; (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;(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; (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); (10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and (11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s); (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 expenditure factor.

6.1.2. Changes to the NER in 2012

As part of the 2012 Rule change on Economic Regulation of Network Service Providers, the AEMC reviewed the decision making framework for opex and capex. The AEMC largely maintained the existing framework in the Rules that were applied to making our 2009-14 determination. This included maintaining the structure of the objectives, criteria and factors.

At the time, the AER clarified the process that the AER should follow when making its decision on expenditure forecasts. The AEMC emphasised the following key principles underlying the assessment process:[162]

- Assessment process must start with a DNSP proposal - The proposal is necessarily the procedural starting point for the AER to determine a capex or opex allowance. The DNSP has the most experience in how a network should be run, as well as holding all of the data on past performance of its network, and is therefore in the best position to make judgments about what expenditure will be required in the future. Indeed, the DNSP's proposal will in most cases be the most significant input into the AER's decision.

- The AER must accept a proposal that is ‘reasonable’ - The criteria require that the AER must accept a proposal if it is reasonable. The AEMC noted that the AER is not "at large" in being able to reject the NSP's proposal and replace it with its own. The obligation to accept a reasonable proposal reflects the obligation that all public decision makers have to base their decisions on sound reasoning and all relevant information required to be taken into account.

- Consider the probative value of materials - To the extent the AER places probative value on the NSP's proposal, which is likely given the DNSP's knowledge of its own network, then the AER should justify its conclusions by reference to it, in the same way it should regarding any other submission of probative value.

- The AER’s assessment techniques in making its analysis are not limited - The DNSP's proposal will in most cases be the most significant input into the AER's decision. Importantly though, it should be only one of a number of inputs. Other stakeholders may also be able to provide relevant information as will any consultants engaged by the AER. In addition, the AER can conduct its own analysis, including using objective evidence drawn from history, and the performance and experience of comparable DNSPs. The techniques the AER may use to conduct this analysis are not limited, and in particular are not confined to the approach taken by the NSP in its proposal.

- The test of ‘reasonable’ must equally apply to the substitute amount - While the AER must form a view as to whether a NSP's proposal is reasonable, this is not a separate exercise from determining an appropriate substitute in the event the AER decides the proposal is not reasonable. Both the consideration of "reasonable" and the determination of the substitute must be in respect of the total for each of capex or opex. The AER, whenever it determines a substitute for a NSP's proposal, is not constrained by the capex and opex criteria from choosing the best substitute it can determine.

[162] AEMC Draft Rule Determination, Economic Regulation of Network Service Providers Rule 2012, August 2012, pages 102-103

6.2. Our initial proposal

As noted above, the starting point for the AER's assessment is our regulatory proposal. With this in mind, our initial proposal provided detailed information to demonstrate that our proposed opex was efficient and prudent. We outlined the drivers impacting our proposal, set out our prudent forecasting method, and demonstrated how our cost categories are necessary to provide standard control services.

Our initial proposal recognised that historical context was relevant to the AER's decision on forecast opex. We showed that in the lead up to the 2009-14 determination, Endeavour Energy was entering a period of renewal and augmentation in the network to address legacy issues from under-investment in the past. Our proposed opex for the 2009-14 period recognised that opex would be impacted by these circumstances, however we strove to incorporate efficiencies by proposing a productivity dividend in our 2008 regulatory proposal.

At the time of the 2009-14 determination, the AER scrutinised our proposed opex in great detail, assessing our opex categories and our efficiency targets. The AER made minor reductions to our proposed opex based on its thorough and comprehensive assessment. The AER also implemented a very powerful incentive termed the Efficiency Benefit Sharing Scheme (EBSS) on Endeavour Energy to incentivise reductions in opex over the period.

The efficiency programs we introduced in the 2009-14 period, together with our prudent delivery models enabled us to reduce our opex to a level well below the AER's allowance. As such, we considered that our actual costs in 2012-13 were an efficient starting point from which to develop an opex forecast.

We then considered the drivers of costs in the 2014-19 period relative to our actual costs, with regard to our regulatory obligations and operating environment. In this regard we noted that our vegetation management costs would need to increase to address a non-compliance issue. We also noted that our network would grow in the 2009-14 period which would impact the activities we require to perform.

At the same time, we recognised that these increases would be offset by our continued efficiency programs. Our forecasting method incorporated the impact of our ongoing efficiency initiatives into our opex proposal for the 2014-19 period. We noted that this would result in the need to fund redundancy costs, but that the efficiency programs overall would result in a net benefit to customers in the longer term.

Overall we considered that our proposal met our key objectives of maintaining the safety and reliability of our network services, while the efficiency programs would assist us meet our goal of affordability for customers.

Together with our contextual description, we also sought to demonstrate how our forecast of opex achieved the opex objectives, and satisfied the opex criteria in the Rules with regard to the opex factors. We summarise how our proposal met the framework under 6.5.6(a) of the Rules, and referred the AER to Attachment 0.03 of our initial proposal. In the sections below we provide a summary of how we sought to satisfy the AER.

6.2.1. Achieving opex objectives

Endeavour Energy included in the building block proposal a total forecast opex for the 2014-19 period that we required to carry out the necessary activities to achieve each of the opex objectives listed in clause 6.5.6(a) of the Rules. This total forecast opex is made up a number of cost categories. These cost categories represent the costs of undertaking a set of interrelated activities, and to operate the various systems necessary to achieve each of the opex objectives.

We outlined the components of our proposed total forecast opex for the 2014-19 period and demonstrated how these cost components are required to achieve each of the expenditure objectives listed in clause 6.5.6(a) of the Rules. These costs are incurred as the result of having capabilities, personnel and systems to undertake activities necessary to deliver the outcomes specified by each of the expenditure objectives. We provided the AER with the following information on our activities.

System maintenance activities and costs

Maintenance opex is required to undertake various activities on Endeavour Energy's electrical network. These activities and the resultant costs are critical to achieve all four opex objectives.

- **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 the NSW jurisdictional standard (ISSC3) 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.

- **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.

Operations and support activities and costs

Operation expenditure are those costs incurred in undertaking the required activities to directly support the operation of Endeavour Energy's network system and include:

- Support expenditure are those necessary costs 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. These costs are essential to the effective running and operation of the network and therefore are required to achieve all of the opex objectives.

- 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 expenditure 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 and queries on improving power factor or load factor.

- 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. This also includes the four technical development programs: Apprentices, Engineering Officer Traineeships, Electrical Engineering Cadetships and the Engineering Graduate Program.
- Finance costs relating to corporate accounting and reporting, budgeting, forecasting, commercial services, investment analysis and business support. Treasury, taxation and cash management. Regulatory reporting and fixed asset management and reporting.
- Other operations and business support costs relating to fleet and logistics management, insurance, human resources management, workers compensation, occupational health, wellbeing and safety, regulation and implementation of non-network alternative programs, management including the Board of Directors, Chief Executive Officer, Chief Operating Officer and Networks NSW Group Management.

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

6.2.2. Satisfying the opex criteria with regard to the opex factors

Our initial proposal was accompanied by expert economic opinion from NERA Consulting on how to interpret the opex criteria in the Rules, and on how to demonstrate that the forecast opex reflected these criteria with regard to the opex factors.

A key element of NERA's advice was that there is no external, observable measure that can be relied upon to demonstrate or conclude that the total forecast expenditure is efficient. In this context, NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent.
- 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.
- We showed that NERA's practical approach reflect the opex factors that the AER must consider in deciding whether it is satisfied that the forecast expenditure reasonably reflects the expenditure criteria.

Methodology employed by Endeavour Energy to derive forecast opex

In our initial proposal we demonstrated that we have a fit for purpose approach to forecasting our operating expenditure for the 2014-19 period.

Our initial step in developing our forecast opex for 2014-19 was to disaggregate our actual costs in 2012-13 (most recent known costs) into various cost categories. These cost categories represented the costs of undertaking a set of related activities to provide standard control services and to achieve the opex objectives (for example, maintenance opex, system control, finance, human resources etc).

When undertaking this assessment we considered whether there were any costs in the 2012-13 year that were non-recurring, such as one-off actuarial adjustments. It also involved considering whether the 2012-13 base year represented an efficient starting point for forecasting opex. We considered that our performance against the target set by the AER in 2009-14 provided demonstration that the starting point was efficient.

We next assessed each cost category to determine whether the forecast opex requirement in the 2014-19 period would be different to our actual costs in 2012-13. This required consideration of the change factors that may influence the efficient costs of providing each opex activity. This included legislative changes, known compliance issues with our existing standards, and changes to our operating environment. For example, with vegetation management we had identified that we had yet to reach full compliance with prudent NSW jurisdictional standards (ISSC3) to manage bushfire and public safety risk, which would result in an increase to our costs in the 2014-19 period to achieve the opex objectives.

We also considered broader factors in our environment that would influence our opex in the 2014-19 period. We considered that a top down approach would provide a more accurate estimate of the resultant change in opex from these drivers of expenditure. In particular we took into account two important elements of the opex criteria through this approach:

- Demand – We calculated the impact of increased customer numbers and maximum demand through our output growth factor.
- Input costs – We calculated the expected change in real costs of inputs used in delivering our opex activities.

Our forecasting approach also explicitly considered the efficiencies we could achieve in the 2014-19 period. This recognised that a prudent business is continually seeking to implement efficiencies when opportunities arise. Our forecast deeply considered the level of efficiencies we could achieve in our circumstances based on a granular assessment of the activities we perform. We also recognised that the benefits of efficiency programs have offsetting costs such as redundancy payouts for affected employees, and additional maintenance from deferring replacement activities.

We sought to show that the resultant approach was ‘fit for purpose’ in that it ensured that the nature of each cost category and its relevant underlying drivers are appropriately accounted for such that the resulting forecast opex is reflective of the efficient costs that a prudent operator would require to achieve the opex objectives. This process gave us confidence that our total forecast opex would reasonably reflect the opex criteria and ensures that the National Electricity Objectives and the Revenue and Pricing Principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient cost we expect to incur in the 2014-19 period.

Our initial proposal also identified the relevant capex factors that align to assessing the prudency of forecasting approach:

- Substitution possibilities between operating and capital expenditure (opex factor 7). Our forecasting process considered the consequential impact of efficient capital investment on our future opex requirements. For instance we identified that reductions in replacement capex will degrade the health of assets on the network, and increase the efficient maintenance costs. We also considered how IT and property capex may impact on opex for these activities.

- The extent to which Endeavour Energy has considered and made provision for efficient non network alternatives (opex factor 10). We considered the extent to which demand management activities taken to defer capex would impact on opex in the 2014-19 period.

- Relative prices of capital and operating inputs (opex factor 6).

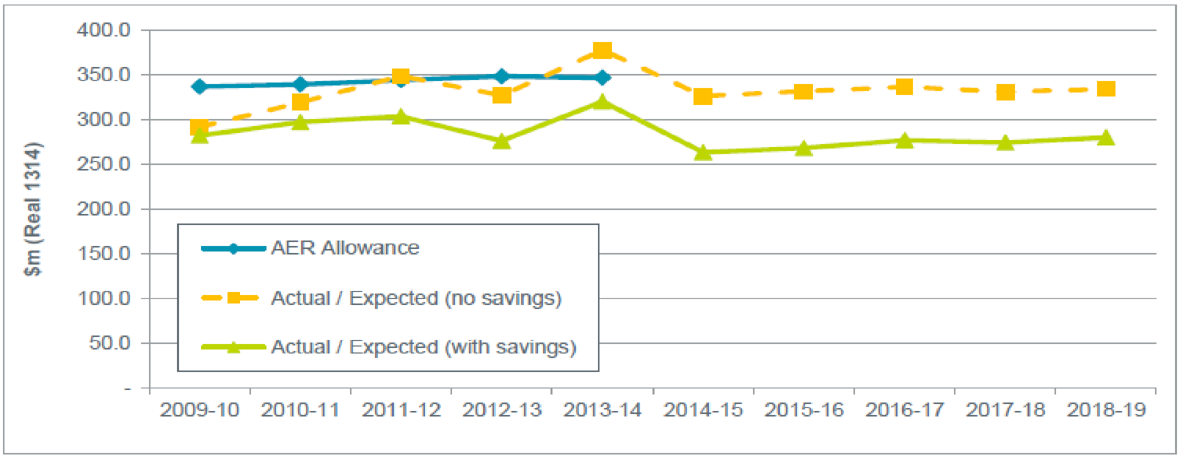
- The extent to which the expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the DNSP in the course of its engagement with electricity customers. (opex factor 5A).

Indicators to assess whether process results in efficient cost

NERA's advice suggested there are partial indicators and other factors that would assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the Rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria. Accordingly, our initial proposal addressed these factors to satisfy the AER that our forecast opex meets the criteria.

Opex factor 5 states that the AER must have regard to the actual and expected opex of the DNSP during any preceding regulatory control period. We demonstrated that our proposal was grounded on our efficient performance in the past, and that this had formed an important element of our regulatory proposal. We showed that we performed significantly better than the targets that the AER had determined were efficient, as can be seen in Figure 6b below:

Figure 6b: Comparison of actual and forecast expenditure in initial proposal compared to AER allowance for 2009-14



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 2014-19 reasonably reflects the efficient costs that a prudent operator would need to achieve the opex objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

Opex factor 4 requires that the AER must consider the most recent annual benchmarking report that has been published under 6.27 of the Rules and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period. 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. The AER was required under the Rules to release its first benchmarking report in September 2014.

In our initial proposal, we submitted a comprehensive report on the limitations and role of benchmarking as a partial indictator (Attachment 0.12 of our initial proposal). Our analysis identified that benchmarking has inherent limitations such as inability to conduct 'like for like' analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistic principles. We noted that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. Importantly, it should not be used to reject a DNSP's proposal, or as a basis to substitute the forecast given the inherent limitations as a tool.

We placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast. This was due to our assessment of the tools that the AER was developing, which we considered did not meet criteria for an effective benchmark as developed by the Productivity Commission. We complemented our analysis by providing a report by Huegin Consulting which provided a factual demonstration of the limitations and shortcomings of benchmarking analysis.

Finally we showed that opex factor 9, which is the extent to which forecast expenditure is referable to arrangements with other persons that do not reflect arm's length transactions, is not applicable to our circumstances, and is therefore is not a valid check on our forecasting process.

6.3. AER's draft decision for opex

In its draft determination, the AER made a constituent decision to reject our proposed opex of $1,364.1 million, and substitute an amount of $1,053.4 million for the 2014-19 regulatory control period, which was 22.8% lower.

6.3.1. AER's methodology for assessing our proposal

The AER noted that its assessment method to review our proposal was consistent with its Forecast Expenditure Assessment Guidelines published in November 2013. The AER's stated approach was as follows:

> *"Our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves. By doing this we form a view on whether we are satisfied that the service provider's proposed total forecast opex reasonably reflects the criteria. If we conclude the proposal does not reasonably reflect the opex criteria, we use our estimate as a substitute forecast.*
>
> *Our estimate is unlikely to exactly match the service provider's forecast because the service provider may not adopt the same forecasting method. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate.*
>
> *If a service provider's total forecast opex is materially different to our estimate and there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not reasonably reflect the opex criteria. Conversely, if our estimate demonstrates that the service provider's forecast reasonably reflects the expenditure criteria, we will accept the forecast. Whether or not we accept a service provider's forecast, we will provide the reasons for our decision."*[163]

The AER's approach to forming an alternative estimate of opex was based on five steps. The AER explained this as follows:

1. *"We typically use the service provider's actual opex in a single year as the starting point for our assessment. While categories of opex can vary from year to year, total opex is relatively recurrent.*

2. *We assess whether opex in that base year reasonably reflects the opex criteria. We now have a number of different techniques including economic benchmarking, by which we can test the efficiency of opex in the base year. If necessary, we make an adjustment to the base year expenditure to ensure that it reflects the opex criteria. We can utilise the same techniques available to assess the efficiency of base year opex to make an adjustment to base year opex.*

3. *As the opex of an efficient service provider tends to change over time due to price changes, output and productivity, we trend the adjusted base year expenditure forward over the regulatory control period to take account of those changes. We refer to this as the rate of change.*

4. *We then adjust the base year expenditure to account for any other forecast cost changes over the regulatory control period that would meet the opex criteria. This may be due to new regulatory obligations and efficient capex/opex trade-offs. We call these step changes.*

[163] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p12

5. Finally we add any additional opex components which have not been forecast using this approach. For instance, we forecast debt raising costs based on the costs incurred by a benchmark efficient service provider. If we removed a category of opex from the selected base year, we will need to consider what additional opex is needed for this category of opex in forecasting total opex."[164]

The AER noted that underlying its approach are two general assumptions: Firstly, that the efficiency criterion and the prudence criterion in the NER are complementary, and secondly that actual expenditure was sufficient to achieve the expenditure objectives in the past.

6.3.2. The AER's decision to reject proposed expenditure

The AER's decision clearly reflects its approach to use its alternative estimate as the reference point for assessing whether our proposed forecast opex satisfies the opex criteria. The AER stated:

> *"We are not satisfied that Endeavour Energy's total forecast opex reasonably reflects the opex criteria. We compared Endeavour Energy's opex forecast to an opex forecast we constructed using the methodology above. Our estimate is of the efficient opex a prudent operator would require to achieve the opex objectives. Endeavour Energy's proposal is higher than ours and we are satisfied that it does not reasonably reflect the opex criteria. For this reason, we have substituted Endeavour Energy's total opex forecast with our total opex forecast."*[165]

The AER was not satisfied that our actual costs in the 2012-13 base year were efficient. The AER were also not satisfied that the rate of change it implied from our proposal met the opex criteria. Finally, the AER identified any other increase from the base year was a step change, and considered that our proposed costs in these areas did not meet the opex criteria.

AER's findings on base year

The AER stated that it tested the efficiency of Endeavour Energy's base opex in 2012–13 using a number of different techniques. Based on these tests, the AER was not satisfied it represents opex incurred by an efficient and prudent service. The AER's findings are set out on page 29 of the AER's draft decision and considers that this results in a 10.3% decrease from the actual costs we incurred in 2012-13.

It can be seen from the analysis that the AER's primary method to assess our proposal relates to benchmarking analysis. Five of the seven assessment methods relate to benchmarking analysis, or adjustments to reflect benchmarks. The AER's conclusions on its benchmarking analysis are set out below:

- Economic benchmarking - Despite differences in the techniques the AER used, all benchmarking techniques show Endeavour Energy performs about 60% as efficiently as the most efficient service providers in the NEM (CitiPower and Powercor).

- Partial Productivity Indicator (PPI) Benchmarking - PPIs corroborate the AER's economic benchmarking evidence. Endeavour Energy appears to have higher costs than more than half of other service providers on total network cost per customer and total opex per customer.

- Category analysis benchmarking - In general, Endeavour Energy appeared to have higher or comparable costs relative to most of its peers for the categories the AER examined.

- Operating differences – The AER found some operating environment differences that it considered affects Endeavour Energy's opex performance in economic benchmarking. Overall, it considered that a 10% allowance for operating environment differences is necessary.

[164] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, pp12-13

[165] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p16

- Direct comparison – The AER found that Endeavour Energy incurred similar total opex to the sum of Powercor and United Energy (who, when combined, incorporate rural and urban network characteristics) over the past eight years despite Endeavour Energy serving only 66% of the customers and operating a circuit which is only 39% the length of Powercor and United Energy's combined circuits.

In additon to benchmarking, the AER stated that it undertook a review of our proposal. The AER found:

> *"…evidence that Endeavour Energy has historically had some inefficient practices is evident from its regulatory proposal and subsequent submissions. For example, Endeavour Energy cites concerns with stranded labour due to the reduction in capex activity since the formation of Networks NSW. Networks NSW CEO Vince Graham has also publicly confirmed the existence of labour inefficiency and uncompetitive enterprise agreements."*[166]

The AER also undertook a review of labour force practices. It referred to its consultant's report , Deloitte Access Economics (Deloitte) which found that Endeavour Energy's labour and workforce management issues meant the base year would not likely represent efficient costs. Deloitte also concluded it is likely that the full benefits of the current Networks NSW efficiency programs will not be realised until the 2014-19 regulatory period.

Based on Deloitte's report, the AER recognised evidence which suggests Endeavour Energy has been improving its efficiency for longer than Ausgrid and Essential Energy so its remaining inefficiency seems to be less than for its two peers. However, the Networks NSW reform program has not looked beyond the three NSW businesses for opportunities to improve efficiency, supporting Deloitte's view that Endeavour Energy has efficiencies it is yet to realise.

AER's findings on rate of change

The AER noted that its forecast rate of change in opex captures the year on year change in efficient base opex. Specifically, it accounts for forecast changes in output levels, prices and productivity (such as economies of scale). The AER considered that these three opex drivers should account for the main reasons why the efficient base level of opex changes over time. The output and productivity change variables capture the forecast change in the inputs required. The price change variable captures the forecast change in the real prices of those inputs.

The AER found that in percentage terms, its forecast rate of change in opex is higher than Endeavour Energy's. The AER concluded that the differences between its forecast rate of change and Endeavour Energy's is mainly driven by forecast output change. It stated that Endeavour Energy proposed a 3% increase in its opex for output change, however after the first year of output change Endeavour Energy proposed management efficiencies to constrain the increase in costs due to output change to CPI.

The AER noted that its forecast output change is a top down approach based on the annual percentage change in Endeavour Energy's ratcheted maximum demand, customer numbers and circuit length. The AER considered that its approach best captured the change in the quantity of services Endeavour Energy must provide to its customers. Therefore it considered it accounts for a more realistic expectation of the demand forecast and cost inputs to achieve the opex objectives.

AER's findings on step changes

The AER considered that we had proposed two step changes (ie: change in costs not related to a rate of change) for vegetation management and capital expenditure prioritisation. The AER stated that it did not include any step changes in its alternative opex forecast.

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[166] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p18

It found that our vegetation management costs resulted in a total $152 million of a step change to opex. The AER did not accept the step change for three reasons. Firstly, Endeavour Energy does not face new regulatory obligations in relation to vegetation management. Secondly, an efficient level of base opex already provides a sufficient allowance for a prudent and efficient service provider to meet its existing regulatory obligations. It noted that Endeavour Energy had not satisfied the AER of a need for additional vegetation management expenditure. Thirdly, the AER concluded that Endeavour Energy's proposal to increase its opex on vegetation management is inconsistent with the operation of the EBSS.

The AER stated that our capital expenditure prioritisation (ie: the redundancy payments related to capital efficiencies) resulted in a step change of $12.3 million. It did not accept the cost as a step change on the basis that it relates to restructuring of Endeavour Energy's workforce. It noted that a prudent and efficient service provider would not require a step change in opex for this cost driver.

Debt raising costs

The AER rejected our proposed debt raising costs. The AER noted that it had applied its own model to assess the debt raising costs that a benchmark DNSP would likely incur in the 2014-19 period. Our response to the AER's draft decision on debt raising costs has been addressed in Chapter 7 of this revised proposal.

6.3.3. AER's Substitute allowance

Having rejected our proposal, the AER's substitute allowance was based on its own alternative estimate. In total (inclusive of DMIA and debt raising costs), the AER's substitute opex was $1,070.9 million, compared to our proposal of $1,384.3 million (real, 2013-14).

In deriving a substitute, the AER adjusted Endeavour Energy's base year opex. On the advice of its consultant (Economic Insights), the AER used the results from its preferred benchmarking model Cobb Douglas stochastic frontier analysis (SFA) as the starting point. However, it considered the following adjustments were necessary:

- The AER compared Endeavour Energy's efficiency to a weighted average of all networks with efficiency scores above 0.75 (CitiPower, Powercor, United Energy, SA Power Networks and AusNet Services) rather than the most efficient service provider (CitiPower) in its preferred model.The AER considered that in combination, these allowances reduce the benchmark level of efficiency to a point that is approximately 18% lower than the most efficient service provider predicted by the Cobb Douglas SFA model alone.[167]

- The AER provided a further 10% allowance for those operating environment differences not completely captured by its preferred benchmarking model.

The AER provided the following table to show the substitute base year. It was satisfied that the substitute base opex forms the appropriate starting point for total forecast opex that reasonably reflects the opex criteria. The AER adjusted our actual opex for 2012-13 from $224.0 million to $201.0 million, a percentage reduction of 10.3%.

[167] The AER noted that the transfer of opex related to services that had been transferred from standard control to alternative control services were not a step change. The AER noted that it removed reclassified ancillary network and metering services from Endeavour Energy's actual opex when comparing it to the opex incurred by benchmark efficient service providers.

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Figure 6c: AER's opex decision methodology

Step	Value	Calculation description / source (all $000)
Step 1: Benchmarking & AER's calculations on benchmarking output[1]		
Determine Endeavour's BM score	59.3%	Analysis by Economic Insights using Cobb-Douglas SFA model applied across 7 years of historic data
Determine efficiency frontier to use	86.2%	Customer numbers—weighted average of top 5 scores (from EI analysis above)
Calculate new efficiency target downwards by 10% 'margin allowance' to account for differences	78.4%	= efficiency target / (1 + margin allowance (10%)) 0.784
Calculate implied opex reduction to reach efficiency target (i.e. gap to the efficient frontier)	**24%**	= 1- (Endeavour eff score / target) = 1-(59.3%/78.4%) 24%
Step 2: Construct theoretical 'substitute base year' opex[2]		
Calculate average of 8 years of opex from 2006 – 2013 (inclusive)	$234.40m	= average ('opex quantity') from RIN data, where 'opex quantity' is past years' opex in $FY13 = 234,400
Calculate the implied opex reduction to move to a theoretical efficient level	-$56.90m	= 234,400 * 24% = 56,904
Reduce this by the implied opex reduction to make it 'efficient average opex'	$177.50m	= average ('opex quantity') – implied opex reduction = 234,400 - 56,904 = 177,497
Escalate average opex to create an efficient 2012/13 opex to account for output growth ('substitute base opex' in spreadsheet)	$194.26m	= average efficient opex * composite growth factor[3] = 177,497*(1 + 9.94%)
Express 'substitute base opex' in $13/14	$201.00m	= 194,256 * CPI index = 194,256 * 1.035 = 201,003
Step 3: Construct theoretical 'efficiency adjustment'[4]		
Adjust Endeavour's reported base year opex (2012/13) to allow comparison (adjust for CAM & service classification changes and remove DRC)	$216.49	= total opex – costs related to service classification change = 271,586 - 55,093 = 216,493
Express Endeavour's adjusted base opex in $13/14	$224.01m	= 216,493 * CPI index = 216,493*1.035 = 224,012
Calculate the difference between the 'substitute base opex' and Endeavour's adjusted base year opex (in $13/14)	$23.01m	= Endeavour's adjusted base opex - substitute base opex = 224,012 - 201,003 = 23,009
Express as a percentage **'efficiency adjustment'**	**10.30%**	= 23,009/224,012 = 10.3%
Step 4: Applying the theoretical 'efficiency adjustment' - The AER's calculation of opex base year and forecast for subsequent years, using equations in Expenditure Assessment		
Applies the AER's forecast 'base, step, trend' opex forecasting formula: $Opex_t = \prod_{i=1}^{t}(1 + rate\ of\ change_i) \times (A_f^* - efficiency\ adjustment) \pm step\ changes_t$ *Where A_f*= the estimated actual opex in the final year of the preceding regulatory control period*		
Calculate, estimated final year opex , A_f^* = F_f is opex allowance for the final year (13/14) F_b is opex allowance for base year (12/13) A_b is the actual opex in base year (12/13)	$279.49m	12/13 actual opex – DRC costs = 271,586 ($12/13) A_b, 12/13 actual opex – DRC costs = 281,081 ($13/14) F_b, Opex allowance for 12/13 = 351,565 ($13/14) F_f , Opex allowance for 13/14 = 350,037 ($13/14) Non-rec. eff. gain = 0 A_f^* = 350,037 – (351,565 – 281,081) = 279,490
Adjust A_f^* (final year opex) for service classification changes	$222.48m	A_f^* – costs related to service classification change = 279,490 – 57,007 = 222,484
Calculate the opex reduction using the ***'efficiency adjustment'*** from benchmarking	-$22.85m	Opex adjustment = final year opex * efficiency adjustment =222,484*10.3% = 22,852
Calculate efficiency adjusted final year opex – a theoretical efficient opex in 2013/14	$199.63m	Theoretically efficient final year opex = 222,484 - 22,852 = 199,631
Calculate opex forecast by applying growth and allowed step changes: $\prod_{i=1}^{t}(1 + rate\ of\ change_i) \times (A_f^* - efficiency\ adjustment) \pm step\ changes_t$ ***Year 1*** (14/15) = (199.63*(1+1.90%) = **$203.43m** (see other years below)		

Secondly, the AER applied its calculation of the rate of change to the substitute base year to derive an opex forecast for each year of the 2014-19 period. The AER noted that in dollar terms, the forecast opex attributed to the AER's calculation of the rate of change was lower than Endeavour Energy's proposed opex forecast because the AER's estimate of the rate of change is applied to a lower base level of opex.

The AER considered that no step changes should be applied to the opex it derived from the substitute opex and rate of change calculation. Finally, the AER also applied debt raising cost and DMIA of $17.4 million.

6.3.4. AER's assessment of opex factors

The AER stated that in deciding whether or not it was satisfied the service provider's forecast reasonably reflects the opex criteria it had regard to the opex factors. This is set out in Table 7.7 of the AER's draft decision. The AER considered that two of the nine factors identified in the Rules were not relevant. The AER also decided to develop two of its own factors both of which relate to benchmarking.

When making its assessment against the opex factors, the AER has sought to show how its assessment method relates to one or more opex factors. In particular, the AER has sought to show how its alternative estimate of opex, including the benchmarking analysis it uses to derive an estimate of the base year, met the factors. For instance:

- Of the seven of the nine relevant factors, the AER refer in some part to its benchmarking analysis.
- When assessing the relative prices of capital and operating expenditure the AER noted that its rate of change adjustment of base year opex captures the estimate of the inputs that Endeavour Energy is likely to face in the forecast period. The AER stated that this ensures its estimate includes adequate compensation for efficient changes in inputs over time. It also notes that it had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. It stated that multilateral total factor productivity analysis considered the overall efficiency of networks with the use of both capital and operating inputs with respect to the prices of capital and operating inputs.

6.4. Issues with the AER's assessment method

We have reviewed the AER's draft decision on opex with a mind to considering whether any revisions are required to incorporate the substance of any changes required by the AER or reasons for it.

In reviewing the decision, we have formed a view that the AER has fundamentally misconstrued its task under 6.5.6 of the Rules. We have identified three areas in which the AER has misdirected itself:

- The AER did not apply itself to the opex criteria to critically assess how our proposal failed to meet them. The AER's assessment has been fundamentally based on deriving its own alternative estimate rather than reviewing our proposal. In doing so, the AER has not constructed their alternative estimate in a reasonable manner, and failed to properly consider why there are differences between the alternative estimate and the draft proposal. Further we contend that the AER's alternative forecast is not capable of accounting for our circumstances, and does not properly account for the range of costs that may satisfy the opex criteria and factors. This is outlined in section 6.4.1.

- Undue weight on benchmarking analysis - The AER has placed unreasonable weight on benchmarking analysis in rejecting and substituting our proposed opex, particularly in circumstances where the benchmarking analysis that has been done is such that it cannot be reasonably relied on. This is clear from the AER's stated techniques, and the manner in which it has sought to address the opex factors. Further, we demonstrate that it is unreasonable to place weight on the benchmarking analysis when making its decision due to the errors and limitations inherent in its development and application. This is outlined in section 6.4.2.

- AER did not consider risks to safety and reliability from its substitute opex - The AER's method for deriving a substitute allowance relies on a benchmarking model that is entirely divorced from the method and cost categories in our forecast opex. In doing so the AER has considered that its task is to set an overall allowance without undertaking a review of activities that underpin forecast opex. We consider this is unreasonable. The AER should have undertaken a proper risk assessment of the substitute allowance to satisfy itself of the implications for additional risk for our business that has not been considered. This is outlined in section 6.4.3.

We consider that if the AER had undertaken its task in accordance with the Rules, it would have been satisfied that our proposed opex satisfies the opex criteria. For this reason, we have seen no reason to revise our proposal in light of the AER's assessment approach.

Before turning to these matters, we note that the AER's assessment method appears to stem from a misconception of its powers following amendments to the Rules and NEL in 2012. The AER state for instance that its determination is premised on an overall revenue allowance, as opposed to its individual constituent decisions.

> *"These legislative changes have made this decision different from our previous decisions. In particular, for the first time, we have specifically assessed our overall revenue decision and its contribution to the achievement of the NEO. We consider this is an appropriate change as we determine an overall revenue allowance We do not seek to interfere in the decisions a service provider will make about how and when to spend the total capex or opex allowance to run its network. The service provider is free to choose how to manage its allowance. For example, we do not approve individual capital expenditure projects that a distributor must then implement. Rather, we determine the sum total of revenue that we consider satisfies the requirements of the NEL and NER."*[168]

We consider that such analysis has infiltrated the AER's assessment of opex, where it has sought to develop a revenue allowance that in its view achieves the NEO. This is seen in Chapter 5 of its overview where the AER summarises the key underlying drivers for its decision and indicate their impact on the constituent components of its decision. It then examines the cumulative effect of drivers on the efficient level of revenue.

The AER's task is to assess our forecast opex under the criteria rather than to derive an efficient level of revenue overall and, in circumstances where it is not satisfied that the forecast opex amount reasonably reflect the operating expenditure criteria, determine a substitute amount that the AER is satisfied reasonably reflects the operating expenditure criteria. This is plain from clause 6.12.1 of the Rules. In approaching the forecast operating expenditure allowance for the 2014-19 period, the AER seems to have misunderstood this requirement. The distribution determination is built on each of the constitutent decisions the AER is required to make pusuant to clause 6.12.1, and the correct application of the Rules in making each of those decisions will provide a revenue stream that meets the NEO. While it should undertake a cross check of its overall decisions, this is in the context of ensuring that it has taken into account relevant inter-relationships..

The AER also seem to have misunderstood the powers in relation to the AEMC's Rule change in 2012 on the approach to be taken to assessing expenditure forecasts. The AER convey a view that the AEMC authorised an approach where the AER use its own alternative forecast as a reference point, and accept that proposal only if the DNSP can satisfactorily explain for the differences.

The AEMC's statements do not suggest that the AER has the power to simply adopt its own forecasting estimate as the sole reference point for determining an efficient forecast of opex. The AEMC stated:

> *"The NSP's proposal is necessarily the starting point for the AER to determine a capital expenditure or operating expenditure allowance, as the NSP has the most experience in how its network should be run. Under the NER the AER is not at large in being able to reject the NSP's proposal and replace it with its own since it must accept a reasonable proposal. But the AER should determine what is reasonable based on all of the material and submissions before it."*[169]

The AER is also of the view that the changes to the NER placed significant new emphasis on benchmarking. The AER stated:

> *"While these general steps are consistent with our past determinations, we have adopted a significant change in how we give effect to this approach, following the major changes to the NER made in November 2012. Those changes placed significant new emphasis on the use of*

[168] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 –Overview, November 2014, p18.

[169] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p vii

> *benchmarking in our expenditure analysis. We will now issue benchmarking reports annually and have regard to those reports. These benchmarking reports provide us with one of a number of inputs for determining the benchmark efficient costs of providing opex."*[170]

As we noted above the AER has placed unreasonable weight on its benchmarking analysis. We consider that the AER has misconceived the AEMC's intent on the role of benchmarking. The AEMC did agree that benchmarking is a critical exercise in assessing the efficiency of a NSP's capex and opex forecasts. It nevertheless did not consider that it should be of greater priority or emphasis than any other opex factor:

> *"Benchmarking is but one tool the AER can utilise to assess NSPs' proposals. It is not a substitute for the role of the NSP's proposal."*[171]

6.4.1. AER's alternative estimate

The AER's decision makes clear that it has given primacy to its own alternative estimate for opex, rather than start with Endeavour Energy's proposal. This is clear from the following statement in its decision, which shows that the AER's starting point is its own 'alternative forecast', and that its test of our proposal against the criteria is whether we can satisfactory explain any difference:

> *"Our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves By doing this we form a view on whether we are satisfied that the service provider's proposed total forecast opex reasonably reflects the criteria. If we conclude the proposal does not reasonably reflect the opex criteria, we use our estimate as a substitute forecast.*
>
> *….Our estimate is unlikely to exactly match the service provider's forecast because the service provider may not adopt the same forecasting method. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate.*
>
> *If a service provider's total forecast opex is materially different to our estimate and there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not reasonably reflect the opex criteria."*[172]

We consider that in applying such an approach the AER has miscontrued its task under the Rules. As we outline below, the AER's task is to review a DNSP's proposal in light of the opex criteria.

Construction of AER's alternative estimate

The AEMC's Rule change clarified that the Rules do not limit the assessment tools available to the AER to assess our proposal. The development of an alternative estimate of opex is not prohibited by the Rules, and is expressly identified by the AEMC as a valid method.

However in this case, we are concerned that the AER has gone outside of its powers by using the alternative estimate as a 'threshold' that our proposal must pass so as to satisfy the AER under 6.5.6(c) of the Rules. In this respect, the AER has presumed that the alternative estimate is correct unless a DNSP can provide satisfactory evidence to show why its proposal differs.

The AEMC's Rule change in 2012 was unequivocal that our proposal was the starting point of the AER's assessment:

> *"The NSP has the most experience in how a network should be run, as well as holding all of the data on past performance of its network, and is therefore in the best position to make judgments about what*

[170] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p13

[171] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p 106

[172] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p12

expenditure will be required in the future. Indeed, the NSP's proposal will in most cases be the most significant input into the AER's decision."[173]

In contrast, the AER's alternative estimate is at best a 'rough guide', without any knowledge or foresight of our circumstances and drivers of expenditure. Indeed if the task were as simple as to develop an alternative estimate, the Rules would simply require a DNSP to explain any increases or decreases relative to the AER's formula.

We therefore consider it unreasonable for the AER to form a view that its alternative estimate is more accurate than our proposal. Further the manner in which the AER has constructed the estimate does not enable to it fully capture costs that may in fact satisfy the opex criteria had a full assessment been undertaken of our proposal. For example:

- The AER's forecast is incapable of taking into account our individual circumstances and our operating differences.
- The AER's test of an acceptable 'step change' is overly narrow, and effectively precludes opex that would meet the criteria, with regard to the factors. For example as discussed in section 6.5 the AER has disallowed increases in vegetation management costs on the basis that there are no new regulatory obligations, and therefore the expenditure is discretionary. This ignores information which clearly shows that Endeavour Energy requires the additional expenditure to address a compliance issue within an existing regulatory obligation, particularly when these costs are market tested costs. The AER's method simply assumes that costs in the base year reflect the amount required to achieve the opex objectives, and does not consider whether additional expenditure may be required to address non-compliance issues.
- The AER's output growth factor cannot account for the changes in relation to the increased maintenance from deferrals in replacement. For example, Endeavour Energy's forecast increase in opex as a result of deferrals in replacing aged assets, which is likely to cause increases in our corrective and fault maintenance in the 2014-19 period.

Did not sufficiently engage with our proposal

In testing why our proposal does not meet its alternative estimate, the AER has not undertaken a sufficient examination of our proposal. Rather the AER has simply assumed that its estimate is correct, and undertaken a superficial review of elements of our proposal. We consider that the AER's narrow review of the initial material we provided in our proposal has not allowed it to make a decision on whether our proposed opex satisfies the criteria, and has failed to properly consider why there are differences between its alternative estimate and our initial proposal.

Attachment 7 of the AER's decision states that it examined our regulatory proposal and supporting information. However, this is not evident in the AER's reasoning. Of the seven assessment techniques used by the AER to assess the efficiency of our 2012-13 actual (base year) costs, five relate to benchmarking. The only areas where the AER has examined our proposal or practices in the absence of benchmarking analysis has been labour practices. Similarly, in reviewing our proposed changes in costs relative to the base year, the AER only examined vegetation management and redundancy costs.

In not examining our proposal, the AER has failed to consider the drivers and circumstances underlying our opex. For instance, the AER has:

- Not referred to the extensive attachment we provided which shows how our total forecast opex achieves the opex objectives and satisfies the opex criteria with regard to the factors.

[173] AEMC, Economic Regulation of Network Service Providers - Final Rule Determination, November 2012, p 111

- Not undertaken an assessment of the activities we perform in achieving the opex objectives, and the costs entailed in doing so. Had the AER undertaken this assessment it would have been in a better position to understand the need and efficiency of our operations with reference to our network and circumstances. For instance, if they had undertaken the assessment the AER would have understood that there are safety and reliability consequences from reducing our maintenance and vegetation management activities.

- Ignored the materials we provided to show that we had responded to the incentives in the framework by performing better than the prudent and efficient allowance set by the AER in the 2009-14 determination. In this respect, we provided compelling information to the AER to demonstrate that our performance was significantly better than the allowance set by the AER as a result of prudent management practices and successful implementation of efficiency programs. The AER should have taken this into account when assessing our proposal. In effect the AER has ignored the vailidy of its own determination in 2009-14, and in doing so has rejected the incentive framework that lies at the heart of economic regulation.

- Did not assess change factors unique to our network and circumstances that would impact our cost structure in the 2014-19 period. For instance, the AER did not undertake a review of retail dis-synergy costs, or the additional maintenance we require as a result of deferring replacement of deteriorating assets.

- Ignored informaton we provided on the efficiencies we forecast to derive in the 2014-19 period, which showed that our forecasting processes had incorporated a level of efficiency that was achievable in our circumstances. Had the AER taken this information into account, it would have drawn the conclusion that the efficiency incorporated into our proposal was significantly higher than industry productivity trends.

6.4.2. Reliance on benchmarking as sole criteria

It is clear from the AER's decision that benchmarking has been the primary evidence underlying the AER's rejection and substitution of our proposed opex. The AER's substitute base year has been derived from a benchmark model. Further, the AER has disallowed step changes on the basis that no further increase is required from the base year. The practical effect has been to determine an opex that is primarily based on the opex of the average of the 'frontier' DNSPs of its preferred benchmarking model.

From a procedural viewpoint we are concerned that the AER has relied on a benchmarking report that was published two months later than the timeline imposed in the Rules.[174] By publishing the report two months late, the AER has not provided us with a procedural opportunity to notify the AER of errors prior to the draft determination. It has also limited our time to make a detailed response on the issues contained in the benchmarking report for the purposes of this revised proposal.

From a substantive point of view, we are concerned that an inordinate weight has been placed on benchmarking analysis, and this has led to an incorrect assessment of our proposal under 6.5.6 of the Rules. We consider that:

- The AER has not given proper regard to other opex factors in its assessment techniques.
- When considering the weight that should be applied to benchmarking, the AER should have had regard to the conceptual limitations of benchmarking analysis, particularly in the Australian context.
- We consider the AER has made a number of errors in application of its benchmarking models.

[174] NER, Clause6.2.7(d)

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Based on our analysis of the AER's draft decision, we have not revised our proposal to incorporate the AER's reasons on benchmarking analysis. We discuss each of these issues below. Our views draw on expert evidence we have attached to our proposal including:

- Huegin Consulting: Response to Draft Decision on behalf of Networks NSW and ActewAGL - Technical response to the application of benchmarking by the AER (Attachment 1.02)
- Frontier Economics: Review of AER's econometric models and their application in the draft determinations for Networks NSW (Attachment 1.03)
- Advisian: Review of AER Benchmarking (Attachment 1.04)
- PWC: Independent Expert Advice on appropriateness of RIN data for benchmarking comparisons (Attachment 1.05)
- David Newbery (Cambridge Economic Policy Associates): Expert report (Attachment 1.06)
- Pacific Economic Group: Statistical benchmarking for NSW Distributors (Attachment 1.07)

Role of benchmarking in the context of the opex factors

The annual benchmarking report published by the AER and the benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant period is one of ten explicit factors that the AER must have regard to when assessing whether forecast opex meets the opex criteria. We consider that the AER has placed undue weight on benchmarking to the exclusion of other factors that it should have regard to. In this way we consider it has given undue weight to benchmarking, particularly in circumstances where the benchmarking analysis that has been undertaken is not robust, including because it is at such a nascent stage of developtment.

The AER's assessment techniques however are almost wholly dedicated to applying benchmarking tools and models to assess our forecasts. This can be seen in the techniques it identifies on page 18 of Attachment 7 of its draft decision. Of the seven techniques identified by the AER, five relate to an examination of our costs relative to our peers.

The AER has referred to only two other techniques – review of our proposal, and a review of labour efficiency. In section 6.4.1 we showed how the AER's review of our proposal was highly superficial and did not meaningfully engage with the materials that we presented. In respect of labour efficiencies, we show in section 6.5.1 that the AER's analysis is without factual basis and once again ignores the material we provided on the level of efficiencies incorporated into our forecasts. Setting aside these reviews suggests that the sole evidence relied on by the AER has been its benchmarking techniques.

The AER's primary reliance on benchmarking also becomes apparent in the AER's consideration of opex factors on pages 22 to 25 of Attachment 7 of its decision. The AER's statements against each factor (with the exception of consumer engagement) refers to its benchmarking analysis as demonstration of how it has considered that factor. By way of example, the AER statements on how it considered the actual and expected operating expenditure of the DNSP during any proceeding regulatory control periods was:

> *"Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Endeavour Energy's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period."*[175]

We consider that such an approach unreasonably refers each factor back to the benchmarking factor, giving a disproprotionate weight to its analysis, and not enabling a meaningful contemplation of each factor. We also note that the AER sought to add two additional opex factors when making its decision, both of which relate to benchmarking. These factors are data sets relating to the AER's RIN and international sources, and any other

[175] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p22.

opex modelling or techniques not in the Annual Benchmarking report. We do not consider additional benchmarking factors are necessary nor do we consider that “any other factor” is available to the AER to circumvent a procedural failing. As noted, the effect of including two additional factors means there is a disproportionate weight on benchmarking analysis in the AER’s assessment when benchmarking was clearly only one of ten explicit factors the AER was required to take into account.

From this type of analysis it is clear that the AER has almost solely relied on benchmarking analysis as a deterministic tool. That is, the substitute allowance developed by the AER is in effect determined by the outcomes of the AER’s preferred benchmarking model. The AER’s reliance on the benchmarking analysis does not meaningfully consider other opex factors that are required to be considered in the AER’s assessment of forecast opex in Endeavour Energy’s proposal or in developing its substitute opex, including actual and past expenditure, and the incentive mechanisms that apply. Had the AER considered these factors it may have concluded that our opex in the 2012-13 base year was significantly better than the determination the AER had set in the 2009-14 determination.

By taking this approach the AER has effectively disregarded its 2009-14 determination which set the efficient forecast opex for Endeavour Energy for the 2009-14 regulatory period and the incentive scheme that it applied to Endeavour Energy for this period. It is not sound regulatory practice and therefore it is not reasonable for the AER to effectively ignore its 2009-14 decision and retrospectively re-determine its view of an efficient level of opex, when it has adopted a base year roll forward approach to determining the efficient level of opex. Adopting a base year approach to determining opex, creates an unavoidable link between the 2009-2014 decision and the current decision, particularly given the formulaic approach the AER has adopted when applying the base year opex.

The 2009-14 determination made by the AER was the basis upon which Endeavour Energy set its business objectives, operations and management decisions for this period. We fail to comprehend how an actual opex outturn that is below the efficient opex allowance determined under a valid AER’s determination can subsequently be found to be inefficient, as the AER found in its draft decision for the 2014-19 period.

In any case, the Rules require the AER to have regard to the individual circumstances of the business and the realistic expectation of costs inputs. Within this context, it is clear that the AER should only ever have contemplated using a benchmarking model(s) and anlaysis to identify areas where further investigation might be warranted.

The AER did not, as in previous determinations undertake a detailed assessment of components of opex or commission an engineering review of maintenance programs. Instead, the AER relied almost exclusively on an untested benchmarking regime to mechanistically derive very large adjustments to the base year opex for the NSW and ACT distributors.

The AER only undertook a review of one aspect of our forecast opex (labour practices) to determine the reasons underlying observed differences in costs that resulted from the benchmarking analysis. We consider that significantly more scrutiny should have been given to the results of the analysis and thorough investigation of whether other inherent factors were the drivers of differences. We consider that it was unreasonable for the AER to deterministically apply benchmarking analysis in the context of the Rules, particularly given the extent to which the AER and its consultant Economic Insights (EI) tried to address environmental variables. In the sections below we discuss the limitations of the AER/EI benchmarking approach and the errors involved in its application. This includes issues with the model specifications selected, the lack of consideration of alternative models and their implications, poor variable selection and the mechanistic application of the results.

Conceptual limitations with benchmarking

The AER developed its benchmarking approach as a central tenent of the Forecast Expenditure Assessment Guidelines and acknowledged throughout the development of the Guidelines that benchmarking has limitations and should be used as one of several tools to assess expenditure. However, when faced with its first application of benchmarking in the context of a determination, the AER has applied its benchmarking approach with little regard to the uncertainties and limitations it had previously acknowledged.

It is very difficult to use benchmarking to identify whether an observed difference in costs relates to inefficiency or to another driver. This is particularly true in Australia due to the heterogenous nature of DNSPs and their operating conditions. As we predicted during the consultation on the Forecast Expenditure Assessment Guidelines and again in our initial proposal, it is impossible to normalise for the array of differences between DNSPs in Australia and each businesses circumstances using econometric models. This is a view shared by our consultants at this time of the development of benchmarking in this context.

The result is that any single benchmarking model will contain elements that will result in bias to toward certain business characteristics, and the results of that model will differ dramatically depending on the model specification used. For this reason, we continue to maintain that benchmarking should be used with extreme caution, and should not, in any circumstances be used in a deterministic way to set operating allowances.

The question then remains, how should the AER apply benchmarking in the context of the NEM and the Rules. There is no definition of benchmarking in the Rules. The NER provides only that the purpose of the benchmarking report is to “describe … the relative efficiency of each Distribution Network Service Provider in providing direct control services over a 12 month period”. The NER does not provide any more specific guidance on what benchmarking involves (and does not specify methods or techniques that should be used or what should be included in the annual benchmarking report.

The Rules refer to benchmarking in Rule 6.2.7 and clauses 6.5.6 (in respect of opex) and 6.57 (in respect of capex). Rule 6.27 requires the AER to prepare and publish an annual benchmarking report. Clause 6.5.6 refers to benchmarking in the context of the AER’s assessment of whether it is satisfied that any forecast of opex reasonably reflects the opex criteria. Clause 6.5.6(e)(4) provides that the AER must have regard to:

- the most recent annual benchmarking report; and
- the benchmark operating expenditure that would be incurred by an efficient DNSP (clause 6.5.6 (e)(4)).

In deciding whether or not it is satisfied that a forecast opex amount reasonably reflects the opex criteria.

All we can conclude from the Rules themselves is that benchmarking is something the AER must have regard to in making its decisions on operating and capital expenditures. However, we note the Rules are silent as to how the AER should have regard to benchmarking and note that the Rules do not specifically require the AER to determine the operating expenditure by using a benchmarking model. The fact that benchmarking is one of a list of matters that the Rules direct the AER to have regard to indicates that benchmarking is simply one of a number of matters that may be relevant to the assessment of a forecast opex amount, and, in circumstances where the AER does not approve a forecast amount put forward by a service provider, in determining any substitute amount. Further, the Rules do not specify what types of benchmarking the AER might have regard to in its analysis.

The Rules require the AER to have regard to the individual circumstances of the business and the realistic expectation of costs inputs (clause 6.5.6 (c)(3)). Within this context, it is clear that the AER should only ever have contemplated using a benchmarking model(s) to identify areas where further investigation might be warranted. Instead, the AER has used an econometric model as a tool by which to determine what it considers to be “efficient” base year operating costs, and then used these costs to determine its substitute opex for the 2014-19 period.

6 OPERATING EXPENDITURE

In June 2008, the Victorian Minister for Energy and Resources submitted a rule change request that would allow for the use of a Total Factor Productivity (TFP) methodology as an alternative economic regulation methodology to be applied by the AER in approving, or amending, determinations for DNSPs.[176]

In response to the rule change request the AER submitted that:

> *"This is not only a significant reform program but it is still in its early stages. It is the AER's view that this transition should be given the opportunity to become better established before significant additional change to the underlying regulatory framework is introduced. In particular, one important pre-condition for the use of any TFP-based approach is the development of a full national cost data-based for DNSPs. Such a cost data-base is currently under development by the AER under the new NER provisions in Chapter 6, but this will take some time to be completed. The AER considers that the effective development and implementation of a TFP approach to network regulation is critically dependent on the collection of robust, consistent and reliable long term information about electricity distribution network costs and operational parameters, from a broad range of electricity DNSPs.*
>
> *…*
>
> *Further, it is generally preferable to apply TFP to firms in a relatively steady state environment (i.e. where the future profile of expenditure and demand is relatively smooth compared to historical levels). This is in stark contrast, however, to emerging trends in distribution network expenditure forecasts, particularly those emanating from NSW DNSPs in relation to their upcoming 2009-14 distribution regulatory periods. These indicate that expenditure over the 2009-14 period is foreast to be typically between 50-100 per cent higher than current periods."*[177]

Recognising the complexities of the issues raised by the rule change request, the AEMC instigated a market review into the use of TFP for the determination of prices and revenues. The AEMC engaged EI to provide advice to the AEMC on the use of TFP. In a report dated 9 June 2009, EI noted: "the regulatory data currently available are not fit for the purpose of a robust TFP analysis of the standard required to base regulatory pricing and revenue determinations on".[178] EI went on to say that there was a strong case for developing a well specified and robust national TFP data for the electricity distribution industry and that such a database:

> *"would allow potential application of an alternative method of regulation in the future".*[179]

Further that is was important that definitions and collection methods remain unchanged:

> *"for an extended period of time to allow formation of a robust database of sufficient length".*[180]

In their 9 June 2009 report, EI emphaised that it is only by carrying out TFP studies that inconsistencies and gaps in the data are fully identified and understood and that there is an important "learning by doing" in using available data for TFP analysis.[181] The EI report basically concludes that it will obviously take a number of years before there is a sufficiently long time series available to make TFP-based determinations, but that if the process was commenced as soon as possible,

> *"it may be possible to start making TFP-based regulatory determinations in the next round of reviews or, more likely, the round after that".*[182]

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[176] Victorian Department of Primary Industries, *Proposed Rules Change to the Australian Energy Market Commission to permit the use of the 'TFP Approach'*, May 2008.

[177] Letter from S Edwell (Chairman, AER) to J Tamblyn (AEMC), 20 August 2008, p 2.

[178] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p v.

[179] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p vi

[180] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p vi

[181] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p vi

[182] Economic Insights, *Assessment of Data Currently Available to Support TFP-based Network Regulation: Report prepared for Australian Energy Market Commission*, 9 June 2009, p viii

Without necessarily agreeing with the views of EI expressed in the 9 June 2009 report, it seems incredible that some five years later, EI would be of the view that the data that has been collected to date forms an appropriate basis for the determination of opex (or capex) allowances. In a submission made to the AEMC's market review, the AER stated that it considered it:

> *"would be beneficial for a trial of TFP to be undertaken before it is applied in regulatory determinations, to provide greater regulatory certainty on the potential outcomes from implementing TFP and ensure that the TFP framework is well understood by all stakeholders".*[183]

In its final report, the AEMC found that a number of conditions would need to be satisfied in order for a TFP methodology to work properly and that such conditions are not likely to be met at that time.[184] The AEMC found that:

> *"Crucially, the current lack of a sufficiently robust and consistent data-set means that it could be too problematic to reconstruct existing data for the purpose of a TFP methodology"*

and that the lack of data prevents

> *"proper testing of the other conditions needed for a TFP methodology".*[185]

The AEMC therefore concluded that the

> *"initial focus should therefore be on establishing a better, more consistent data set".*[186]

The AEMC determined that a two-stage process should be adopted for rule changes. First, an initial rule to require service providers to provide specified regulatory data that would permit the AER to test for the conditions necessary for a TFP methodology and to undertake intial paper trials of the calculations.[187] Only after this had been done could a second stage, involving a detailed design of a TFP methodology and the making of a rule allowing for a TFP methodology to be adopted, be considered.[188]

The AEMC went on to note that the regulatory data provided to the AER under the first stage would assist the AER in meeting its obligation (as it then was) to have regard to efficient benchmarks when making regulatory determinations.[189]

In mid-2009, the AEMC, EI and the AER were all of the view that there was not an appropriate data-set that would enable a TFP methodology to be used to set regulatory allowances. Further, that it would be some time before any such data set would be available that would even permit the testing of a TFP methodology to assess whether it could even be used as part of setting such allowances. Again, the AEMC, EI and the AER were all of the view that if there was to be any move to the use of TFP to set regulatory allowances, a trial period would be necessary prior to any implementation. While the AER may not be proposing to use TFP to set Endeavour Energy's regulatory allowance, the considerations that apply to the use of TFP to set such allowances, apply equally to the use of MPFP to set operating expenditure allowances.

In light of the AEMC materials considered above, it could not have been the AEMC's intention that the 2012 amendments to the Rules which the AER says places "significant new emphasis"[190] on benchmarking, would result in the AER determining such a significant component of the regulatory allowance by reference to benchmarking of the type undertaken by the AER. The AEMC essentially says in its final review report that the

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[183] Letter from S Edwell (AER) to J Tamblyn (AEMC), 30 October 2009, p 1.

[184] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[185] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[186] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[187] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[188] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[189] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

[190] Attachment 7, p 7-13.

use of such a benchmarking technique as an option for setting regulatory allowances would need to be the subject of a second step once it has been established that the necessary conditions for the use of such methodologies have been, or are likely to be met, and it is considered that the introduction of such a methodology would contribute to the national electricity objectives. This second step has not occurred. As such, the AER cannot, and should not, rely on the benchmarking it has undertaken to fundamentally determine Endeavour Energy's forecast opex allowance, even putting to one side for the moment the fundamental difficulties with the benchmarking the AER has actually conducted.

More recently, in its April 2013 report on electricity network regulatory frameworks, the Productivity Commission confirmed that the use of benchmarking for electricity networks in Australia was at a nascent stage:

> *"A major study ranked Australia as a relatively unsophisticated user of benchmarking in electricity networks. Recognising this, the AER has recently reviewed the use and methods of benchmarking by other energy regulators, and is collecting data that would allow it to undertake more elaborate benchmarking. However, the AER should adopt further measures to ensure the successful use and evolution of benchmarking…"*[191]

One of the main messages of the Productivity Commission report included:

> *"At this stage, benchmarking — which compares the relative performance of businesses — is too unreliable to set regulated revenue allowances. Nevertheless, greater and more effective use of benchmarking could better inform the regulator's decisions."*[192]

Recommendations of the Productivity Commission included:

The AER's regular aggregate benchmarking of the performance of network businesses should include comparions of: multifactor productivity – the output of services for given inputs; separate productivity of capital, labour and intermediate inputs. The results should control, to the best extent available, for any significant variations in the operating environments of the businesses, including customer density, line type and length, reliability requirements, and the age of relevant capital assets.[193]

In any of the next rounds of regulatory determinations, the AER should not use aggregate benchmarking as the exclusive basis for making a determination. Instead it should use aggregate benchmarking as a disgnostic tool in responding to business cost forecasts.[194]

The AER should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.[195]

The AER should collaborate with other leading regulators, academic experts and global commercial specialists to enable robust meta-analysis of electricity network benchmarking results from individual country (and where credible, multi-country) studies.[196]

The AER should submit its major benchmark analyses of electricity networks for independent expert peert review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to guage the degree of uncertainty in the results.[197]

The Productivity Commission's conclusion on benchmarking as at April 2013, was that there is "little immediate scope for benchmarking to play a decisive role". However, that an increase in benchmarking for diagnostic and informational purposes was likely in the near term in light of the November 2012 rule changes

[191]Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 33.

[192] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 3.

[193] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 52 (recommendation 8.1).

[194] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 54 (recommendation 8.5).

[195] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 54 (recommendation 8.6).

[196] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 55 (recommendation 8.9).

[197] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 55 (recommendation 8.10)

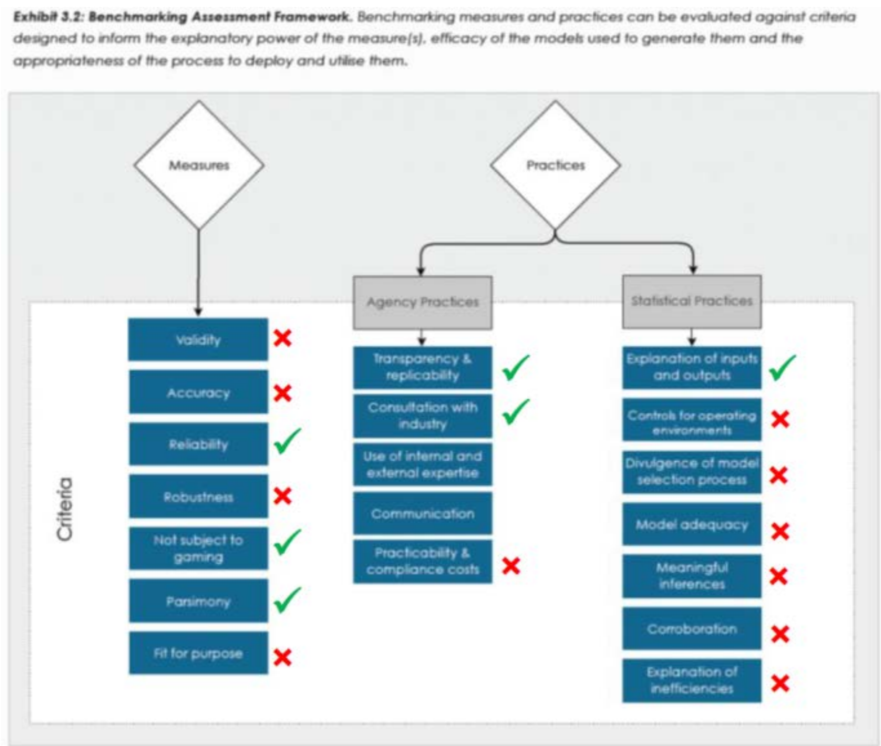
and that, over time, repeated use of benchmarking models will improve the reliability of the models' estimation of network efficiencies and increase the potential for them to have greater weight in regulatory decisions.[198]

Neither the Rules nor the AEMC explain what the AER should use to benchmark DNSPs. However, the Productivity Commission in its 2013 report did identify the criteria by which best practice benchmarking could be identified.

To identify whether the AER's approach to benchmarking is consistent with best practice and therefore fit for purpose in the context of a regulatory determination, our consultants, Huegin, has assessed the AER's approach against the Productivity Commission's best practice measures of benchmarking as outlined in its 2013 report.[199]

Huegin Consulting found that the AER overall has failed to apply a benchmarking approach that is consistent with best practice. Huegin identifies some areas where the AER approach performs well against the criteria. It finds that the AER fails to meet four out of seven criteria set by the Productivity Commission to identify best practice measures of benchmarking and fails six of seven criteria established to determine best practice Statistical Practices. The AER performs best in relation to Agency Practices but still fails to meet all criteria. The fact that the AER's approach does not reflect best practice is the first indication that the AER should not have relied on its benchmarking approach and placed such weight on it in making our draft determination. A full explanation of the Productivity Commission criteria and Huegin's assessment of the AER's benchmarking practice against this criteria is shown in the Huegin report..

Figure 6d: Huegin Assessment of AER Benchmarking against Productivity Commission Framework



[198] Productivity Commission, *Electricity Network Regulatory Frameworks,* Report No. 62, 9 April 2013, p 334.

[199] Productivity Commission 2013, *Electricity Network Regulatory Frameworks, Report No. 62, Canberra*

6 OPERATING EXPENDITURE

Errors in application of benchmarking

The AER has inappropriately applied its econometric benchmarking model. The results of the model have been applied without applying appropriate safeguards in the form of thorough data preparation and the testing of results. This has led the AER to reject and substitute our proposed opex in a manner that does not satisfy the opex criteria in the Rules, and subsequently does not meet the NEO and Revenue and Pricing Principles in the Law.

Furthermore, it was imprudent of the AER to develop a benchmarking model for the specific purpose of deriving a base year opex adjustment given the known difficulties of benchmarking within the Australian context – a context known for its very small sample and for its heterogeneity.

In doing so, the AER did not apply itself in sufficient detail to the consistency of reporting in the RIN or the comparability of international data used in its models, nor did it apply itself to appropriate testing of models and input variables, nor provide sufficient time for peer review of the benchmarking approach,

This has resulted in the AER not only misdirecting itself in its use and application of benchmarking and therefore its application of the Rules themselves, but the AER has made a decision to reject and substitute our proposed opex based on error, poor judgment and complete disregard of the consequences of its decision to the safety and maintenance of our network. By outsourcing its intellectual role as regulator to its benchmarking consultants Economic Insights, the AER has not made a decision that is consistent with the Rules or delivered results for customers that are consistent with the NEO.

The following sections outline the errors that have identified and are supported by our experts Frontier Economics, PEG, Huegin Consulting, David Newbery, Advisian and PWC.

Use of an untested and non-peer reviewed model

The AER asserts correctly, and we agree that it widely consulted on the benchmarking models it intended to use. However, despite the AER having invited comment, we consider our feedback on its Forecast Expenditure Assessment Guidelines consultations was not appropriately incorporated into its final document. We noted the untested and immature nature of the approach the AER intended to use, and suggested a very cautious approach to its use in regulatory decision making.

As this is the first time the AER had relied on such models it should have released the models in advance of them being applied to regulatory determinations. This would have enabled proper peer review.

Furthermore, we contend the AER departed from its final Forecast Expenditure Assessment Guideline by making substantial changes to the way it undertook benchmarking approach for the draft determination. Specifically, this included changes to the techniques utilised, the model specification being used and the data used to derive the results. As a result the models are not consistent with those set out in the AER's Guidelines, and upon which consultation was based, and as a result the models that have been used have not been subject to consultation or any peer review.

As such, the AER did not follow proper process and knowingly applied an immature and under-reviewed model to derive substantial cuts to operating expenditures for all four companies in NSW and ACT. Not only are the opex adjustments greater than any imposed by a regulator internationally which would naturally highlight a need for cautious approach, the AER relied on the model exclusively as a measure of inefficiency and basis for adjustments to the base year allowance.

Had the models been released for proper review prior to their application in the context of the draft determination, such large adjustments would not have been made as the AER would have been made aware of the false confidence it had in the modelling results.

Endeavour Energy

Inconsistency of results

Sensitivity of the models selected and their specification has been found to significantly influence the relative ranking of efficiency results. Models run by Economic Insights, PEG, Huegin and Frontier all demonstrate the variation in results that can be achieved through the use of different modelling techniques and model specifications. The AER/EI was misdirected when it rejected models that did not confirm its expected results. This is evident as the extent of the variation in outcomes itself indicates the poor explanatory power of the model as a proxy for real operating costs of the businesses.

The AER and its consultant Economic Insights argue that the selected model was tested with three other models and the results were confirmed as being similar across all. We argue that such confidence is misplaced as the models are effectively variations of the same model rather than separate and distinct models. The AER and EI state that in their opinion all material parameters have been taken into account and as a result, the relative performance of the networks relates to management performance (inefficiency) and not to other environmental factors that have not been addressed within the model. This finding has been directly refuted by Frontier Economics in their expert report where they demonstrate that when variables are incorporated into the models to test for heterogeneity (company specific factors) and efficiency, Frontier find that almost all of the variance can be attributed to the heterogeneity of the sample.

False Frontier

The AER/EI has applied an average of data reported from 2006-2013 in its SFA model to lessen the impact of any year on year variation. The comparison of the NSW/ACT distributors with the frontier businesses as of 2009 has the effect of comparing the distributors at the time of greatest difference – the first year of higher expenditures in NSW associated with higher capital expenditure, and at the mid-point of the previous period for the frontier firms. The use of any other averaging period (i.e. 2008-2013, 2009-2013, etc and up to 2013 alone) produces different results that show a more contracted spread of results.

The use of averaged opex data sets the frontier at a point in2009 and rolls it forward for CPI. Since 2009, the increase in operating expenditure of the frontier businesses has been greater than CPI, and thus, the target frontier is set at a level that the frontier businesses even now, cannot achieve. Evidence from the SA Power Networks regulatory submission shows significant increases in operating expenditure forecast for the forthcoming period as a result, in part, of higher maintenance costs driven by higher failure rates and inspection costs.[200]

We also note the concerns of independent regulators in Victoria about the backlog in maintenance tasks that have been highlighted in their recent report.[201] In addition, we understand anecdotally that frontier businesses in Victoria are planning to increase opex in their forthcoming regulatory period.

The use of 2009 data for Victorian DNSPs fails to capture the significant financial impacts of the outcomes of the Victorian Bushfire Royal Commission on both recurrent and short to mid-term expenditure. We note the concerns of independent regulators in Victoria about the deterioration in performance of the Victorian DNSPs, as demonstrated by increases in asset failures and fire starts over three successive years to 2013. In addition, backlogs in both maintenance tasks and safety programs in maintenance tasks that have been highlighted in their recent report.[202]

We are concerned that by using an average operating cost, the AER has established a false frontier – one that even those businesses on the frontier in 2009 can no longer meet. We argue that the false frontier is a dangerous benchmark as it does not represent a sustainable level of expenditure for a network business operating to meet modern safety and asset management obligations.

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[200] SA Power Networks, Determination for 2015-20, 2014, 87.

[201] Electricity Services Commission of Victoria, Safety Performance on Victorian Electricity Networks, 2013.

[202] Safety Performance on Victorian Electricity Networks, 2013.
http://www.esv.vic.gov.au/Portals/0/about%20esv/FINAL%20Annual%20Safety%20Performance%20Report%202013%20V1.PDF

In terms of EI model results, Huegin has found that if the model is re-run using 2013 data only, the frontier moves towards the NSW DNSPs by 9% which has the effect of reducing any opex adjustments made by the AER by 9% for each business. Huegin does not contend that the frontier reflects efficient costs, but has made these calculations to demonstrate the real consequence of the AER's decision to apply averaged variables, and apply the result of the model mechanistically.[203]

The mechanistic application of results from the model takes little account of regulatory changes over time nor investment cycles that have driven expenditure in the past, or will drive expenditure in the future.

Poor variable selection

There is significant debate around the variables that should be used in econometric modelling of cost functions of electricity distributors. The variables that best represent inputs to the cost function or the outputs of provision of electricity supply by distributors in Australia are not universally agreed. Variables can be selected in two ways. They can be selected up front based on intuition or precedent, or by testing a range of parameters to determine which is most statistically significant. The AER and its partner EI determined the input and output variables using intuition and assessment of inputs contributed by the business and outputs seen by customers.

A contrasting method to identify appropriate input and output variables is to recognise a wide range of potential inputs and determine through statistical analysis which of those is statistically significant, and weed out those that are not significant. This is the method preferred by our consultant PEG.

In either case, the selection of variables is limited to data gathered. Despite the significant collection of data via the RIN, Economic Insights was unable to make use of the bulk of the data because its preferred modelling approach - Cobb Douglas SFA model - required a large data set, which in turn limited the availability of variables that could be used within the modelling to those that were consistently reported across selected international jurisdictions.

PEG argues that the failure to test a range of variables for significance due to the limitation of the comparability of the Canadian, New Zealand and Australian data set has led to significant variables being omitted from the models, and differences in performance being attributed to efficiency or lack thereof, rather than correctly attributed to omitted variable bias. Variables that PEG found to be significant in their study conducted for the AER using Australian and US data were not able to be included in the EI models due to the lack of comparable data available in the Canadian and New Zealand data set. In this case, the use of international data from Canada and New Zealand had a profound negative effect on the explanatory power of the EI model.

Australia is a particularly difficult region in which to benchmark electricity distributors due to the small and heterogeneous sample. The heterogeneity can only be overcome by inclusion of environmental variables into the selected model. However, the small data in Australia set limits the number of variables that can be considered. Due to this limitation, significant effort is required to ensure that differences within the data set are minimised and that differences in activity type, scope, and regulatory requirements are normalised prior to the data being used for modelling.

Like PEG above, Advisian and Huegin notes with concern the impact of excluding meaningful variables. Huegin on page 40 of their report (referred to as Exhibit 4.4) assess the drivers of network costs and test them against the variables selected by the AER/EI models. Of the three variables included in the model, line length was assessed as having the strongest relationship with cost, with a number of customers having a moderate impact on cost. Peak demand was assessed as having very little relationship to cost at all.

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[203] Huegin, 2015, p38.

Figure 6e: Huegin Consulting's assessment of cost categories, cost drivers against AER benchmarking variables.

Cost Category	Contribution to Industry Costs	Activities	Primary Drivers	Customers	Peak Demand	Line Length
Maintenance Costs	17%	Inspection	Schedule, design, location	None	None	Moderate
		Routine corrective	Design, schedule	Moderate	None	High
		Non-routine corrective	Failure rates, design	None	None	Low
Emergency Maintenance	10%	Assisted	Exposure, proximity	Low	None	Moderate
		Unassisted	Weather	None	None	Moderate
Vegetation Management	13%	Audit	OH network, location, terrain	None	None	Low
		Clearance	OH network, location, vegetation growth rate	None	None	Low
		Tree trimming	OH network, location, vegetation growth rate	None	None	Low
Corporate Overheads	17%	Executive	Scale	Moderate	None	None
		Legal, HR, Finance	Employees, energy served, network service area	Moderate	None	Low
		Regulatory, insurance, debt and equity raising	Energy served, revenue	Low	Moderate	Low
Network Overheads	39%	Network control & systems operations	Location, complexity, level of automation	High	High	Moderate
		Network management	Design complexity, location	Moderate	Low	Moderate
		Network planning	Location, design complexity	Moderate	Moderate	Moderate

Furthermore, Advisian has also identified missing cost drivers and have stated that the variables utilised do not reflect a reasonable set of variables available in the Australian RIN information that contribute significantly to differences in cost drivers for the NSW DNSPs.[204]

- Asset types and volumes (line type, voltage and lengths, installed capacity, transmission point connections)
- Vegetation management differences (responsibility, presence of vegetation, growth rates)
- Spatial density
- Reliability trends
- Physical asset ages (rather than remaining economic lives).

The limitations of the Ontario data has meant the following drivers of opex have not been taken into account:

- Asset age
- Climate and environment
- Customer demographics
- Network design
- Network voltages

[204] Advisian, Review of AER Benchmarking, January 2015

- Network accessibility
- Network utilisation
- Reliability standards
- Scale
- Policy and regulation
- Physical environment in which the business operates

These factors will all explain part of the opex differences between networks and have not been picked up in the AER's analysis. Not all factors are significant as explanations of the business costs but they underline the importance of treating the results of modelling as indicative only, and something that should trigger further investigation rather than treated as a definitive calculation of efficiency.

We asked Advisian to assess the validity of the variables as real cost drivers. Advisian argue that changes must be made to the AER's model to better reflect differences in the volume and nature of the assets that are operated and maintained by each distributor in order to remove the influences of productivity differences which relate to geographical and inherent network design issues that are outside the control of the businesses.

Advisian highlight three principal factors that are highly material to determining the efficient opex requirements for the business which they argue have not been appropriately taken into account in the model for the purpose of determining efficient opex.

- The use of total installed zone and distribution transformer capacity rather than ratcheted maximum demand to recognise differences in security requirements, utilisation and load distribution across the network;
- The relativity between route length and circuit length as well as a correction of rural distributors to account for the lower opex required to maintain SWER line in comparison to conventional three phase distribution lines;[205]
- The recognition of the impact of spatial density (customers per km^2) as distinct from linear density (customers per km^2) on the nature and configuration of electricity distribution networks, and consequently on the efficient opex requirements for a distribution network.[206]

PEG also found that substation capacity was a much more statistically significant variable than peak demand in their study for the AER and in other studies they have conducted but this variable could not be used in the EI model due to the absence of comparable Canadian data.

Previous analysis of the New Zealand electricity distributors undertaken by EI demonstrates the ways in which the input and output variables can be treated to account for differences between distributors.[207] For example, in this study, line length was scaled by operating voltage. In the report EI also discuss the desirability of using reliability performance as an output variable. The omission of reliability in EI's current modelling was highlighted by Advisian as further evidence of the inadequacy of the analysis undertaken.

Use of dummy variable

EI accept that there are differences between the operating environments in various countries and as a result included a dummy variable designed to take account of country specific differences. We do not consider that the use of a dummy variable has sufficiently addressed the inherent differences in the international data. This view is supported by Frontier Economics who argue that:

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[205] Single Wire Earth Return (SWER) line consists of widely spaced poles with a single high tension conductor strung between and was historically used as an inexpensive means to electrify rural areas. In comparison to conventional three phase 11kV or 22kV distribution lines, SWER lines typically require less than half the poles due to average spans in the order of 200m in length and one quarter of the total conductor length. From an opex perspective, this translates to approximately half the pole inspections and minimal maintenance of pole top structures. However there is generally no opex benefit for 'per km' line inspections.

[206] Advisian, Review of AER benchmarking, January 2015, p42.

[207] http://www.economics.ubc.ca/files/2013/06/pdf_paper_erwin-diewert-electricity-distribution.pdf

> *"…simply including country dummy variables is an insufficient way of controlling for specific differences between networks and between countries. The dummy variable simply shifts the intercept terms, without affecting the slope coefficients, which…is a an insufficient method of controlling for differences."*[208]

Newbery is also critical of the use of dummy variables as the panacea for inter-country operating differences and says that

> *"Including a dummy variable in the model specification does not necessarily control for these within and across country differences. A dummy variable only controls for level differences between datasets not cost relationship differences."*[209]

It is the different relationships between environmental factors and cost that is precisely why Frontier recommend that substantial effort is spent preparing data properly before it is applied in a model. This view is supported by Newbery in his separate report where he raises concerns that the data relied upon by the AER has not been sufficiently normalised before being used in the modelling, and notes that the "failure to normalise the data may lead to unreliable results, and potentially the choice of inappropriate models of specifications."[210]

Insufficient data preparation

There is little evidence supplied by the AER or EI that they have investigated the suitability of the data they have used for benchmarking purposes. Our analysis and the views of our expert consultants reveal a number of issues with the data which reduce its accuracy, coherence and suitability. These are:

- There are errors in the international data, and issues with comparability to Australian data.
- There are errors in the adjustments made to Australian data utilised.
- The RIN data by NEM distributors have not been reported consistently. No analysis has been undertaken of the effect of opex/capex tradeoffs, cost allocation and capitalisation policies.

In respect of international data, Economic Insights used data from Ontario as part of its modelling. It is unclear what level of data review was undertaken by the AER or its consultants as our consultants Frontier, were quickly able to identify data errors in the Canadian data set. The presence of such errors suggests a worrying lack of regard for the importance of proper data preparation for an effective benchmarking exercise. These concerns have been further justified as the opex used to compare Canadian firms with those in Australia has been found not to be comparable. The AER and EI have failed to investigate the consistency of the Ontario data closely enough. Neither EI or the AER present any information about detailed data consistency checks.

PEG was involved in the development of the Ontario data and has advised us that operating costs in the Ontario sample:

- Exclude costs of maintaining substations with primary voltage exceeding 50kV.
- Include costs associated with public lighting, meter provision, meter reading, and customer connections.

Frontier also point out the differences in the definitions of other variables used in the analysis. Frontier provide the definitions of the variables used for reporting data in Australia, New Zealand and Ontario in Table 9 of their report.[211] The differences in definitions are clear. For example, the circuit kilometers definition in New Zealand

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[208] Frontier Economics, Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW: A report prepared for Networks NSW, January 2015, p47.

[209] Newberry, Expert report, January 2015, p11

[210] Newberry, Expert report, January 2015, p11

[211] Frontier Economics, Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW: A report prepared for Networks NSW, January 2015,, p49.

specifically state that “when a pole or tower carries multiple circuits, the length of each of the circuits is to be calculated individually”. In direct comparison, the definition in the RIN specifies that “…each SWER line, single-phase line, and three-phase line counts as one line”. In relation to customer numbers, the definition used in New Zealand requires DNSPs to include inactive accounts, but in contrast, the RIN states that “only NMIs for active customers may be counted”.

The fact that these differences have come to light after the AER has published its draft determination is concerning, as it highlights the lack of due diligence that was undertaken when reviewing the data fitness for inclusion in their analysis.

The increase in the sample size has done little to add meaningful comparators to the data set. Many of the businesses in Ontario are municipal utilities servicing small communities. EI tried to address this issue by using a ‘medium’ data set in their analysis. However, even the ‘medium’ population contains 41 distributors that serve between 20,000 and 100,000 customers, and only 12 companies in Ontario and New Zealand that serve more than 100,000 customers. In comparison, the average sized network in Australia serves more than 730,000 customers.

Frontier Economics undertook a further review of the comparability of data between Ontario and Australia and report that Australian distributors are on average four times larger than the Ontarion distributors and only one business of 86 in total is comparable in size to Australian businesses when comparing circuit length. Advisian put this comparison in another way by noting that Ontario is approximately 60% of the area of Queensland with the largest business, Hydro One serving approximately 75% of the province . This leaves approximately 70 DNSPs serving a relatively compact area that is comparable in size to either Victoria (5 DNSPs) or New Zealand (27 DNSPs). Advisian also pointed out that:

> *“the Ontario Government’s Ontario Electricity Distribution Sector Review Panel (OEDSRP) does not consider either its individual DNSPs or industry structure to be comparable to the other provinces within Canada, or states in Australia.”*[212]

It is therefore concerning that the AER has ignored this advice and used data from Ontario in a benchmarking model developed for the express purposes of identifying the relative efficiency of Australian DNSPs.

Finally, Advisian highlight the most stark comparison of all. They argue that the issue that distinguishes Australia from many overseas comparisons is the large variation in spatial customer density between the 13 Australian DNSPs which ranges from 0.4 customers / km^2 (Ergon Energy) to 2050 customers / km^2 (Citipower), - a ratio of 1 : 5,215. This ratio is significantly greater than the linear density ratio of 4.2 customers / km (Ergon Energy) to 75 customers / km (Citipower) - a ratio of only 1 : 17.4.[213]

As well as being significantly smaller than the Australian networks the Ontario networks face:

- Different environmental factors such as maximum and minimum temperatures and extent of snow fall.
- Different legal, industrial relations and regulatory regimes
- Significantly different networks in the extent of underground cables, length of of high voltage network and circuit length per customer.
- Different relationships between opex and cost drivers.

These differences in cost structures and drivers between the Australian and Ontario based business are significance as the results of EI’s Cobb Douglas SFA appear more similar to the results for Ontario alone than to the results for either Australia or New Zealand. Frontier Economics tested the comparability of the data from a statisitical perspective (referred to as ‘poolability’).

[212] Advisian, Review of AER’s Benchmarking, January 2015, p25

[213] Advisian, Review of AER’s Benchmarking, January 2015, p29.

> *"We tested for the poolability of the data from the three countries by re-estimating EI's preferred model with the addition of variables that could pick up differences between the countries in the values of the elasticity on the four main drivers of costs (customer numbers, circuit length, racheted maximum demand and share of underground cables) as well as time trends….(W)e tested the hypothesis that these deviations can be assumed to be zero, in which case the pooling of the data for the three countries is justified. The results … of this poolability test overwhelmingly reject this hypothesis."*[214]

Frontier also undertook a review of differences between distributors across the three countries and quickly reach the conclusion that given the vast differences in scale and cost structure when combined with the lack of data consistency across and within countries, the differences purported to be efficiency in the EI model is more likely to relate to latent heterogeneity.

Frontier quickly reach the conclusion that given the vast differences in scale and cost structure when combined with the lack of data consistency across and within countries, the differences purported to be efficiency in the EI model is more likely to relate to latent heterogeneity.

In relation to the RIN data, the Australian data itself is not free of error. The costs reported by NEM distributors have not been reported consistently between businesses. The audits conducted by each company reviewed the consistency of reporting and compliance with the guidance provided by AER within each company, but did not compare data interpretations and reporting practice between companies.

PWC was engaged to review the data relied on by EI in the economic benchmarking RIN including each DNSP's Basis of Preparation document and found that:

- Inputs used to calculate network length were subject to different interpretations across businesses
- There are differences in cost allocation methods which has implications for costs assigned to opex (as opposed to capex)
- There are material differences in accounting methodologies and application of accounting standards which have the potential to impact the size of opex used in EI's calculations.[215]

The scope of activities between distributors is also not comparable. One example is vegetation management where this activity is jointly managed by distributors and local councils in Victoria, but solely by distributors in other jurisdictions. Furthermore, vegetation management costs correlate significantly with rainfall which varies significantly across jurisdictions. Without accounting for differences in scope or the inherent costs driven by network location, the AER is comparing higher cost businesses with lower cost businesses and attributing differences to management performance (efficiency) rather than inherent and uncontrollable differences between.[216] With this in mind, the AER's use of vegetation management costs to validate the benchmarking outcomes across the NSW DNSPs would appear misguided.businesses. With this in mind, the AER's use of vegetation management costs to validate the benchmarking outcomes across the NSW DNSPs would appear misguided.

In relation to the AER comparisons of vegetation management costs specifically (category benchmarking), Advisian argues that:

> *"the AER has relied on an erroneous and inconsistent assessment of Essential Energy's vegetation management expenditure to support its conclusions that the NSW DNSPs are inefficient."*[217]

They go on to identify a number of analytical inconsistencies in the AER's 'detailed review' which include:

[214] Frontier Economics, Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW: A report prepared for Networks NSW, January 2015, p24

[215] PWC, Independent expert advice on appropriateness of RIN data for benchmarking comparisons, January 2015

[216] Advisian Review of AER's Benchmarking, January 2015, p27

[217] Advisian, Review of AER Benchmarking, January 2015, p4.

- The failure to fully consider the vegetation management information provided by the DNSPs in response to the AER's RIN requirements;
- The failure to account for differences in DNSP responsibility for vegetation management works between jurisdictions;
- Analytical inconsistencies and errors in the calculation of overhead route kilometres;
- The ultimate reliance on a single year result for one business (Essential Energy) to infer that all NSW DNSPs are inefficient;
- Reliance on an erroneous assessment of the reliability impact of vegetation outages to infer that the impact of vegetation outages is increasing.[218]

Frontier also point to a lack of specification within the RIN compared to that which is common in other jurisdcitions, namely Great Britain. Frontier argue a step change is required before data is of suffiicent quality to be able to be used in the context of a price review.

Post-model adjustments

The only environmental variable that has been directly considered by EI is the simple proportion of overhead and underground assets. All other adjustments have been made outside the model.

Professor David Newbury in his report considers that the environmental differences, "particularly the capitalisation policies and greater proportions of high voltage lines, are sufficiently material to be made either through the use of explanatory variables in the modelling or via adjustment prior to conducting the modelling. (Newbury) consider(s) that making adjustments after the modelling for material differences in companies' cost reporting is not in line with the approach used by Ofgem, the UK electricity and gas regulator, which is considered a leader in the use of comparative benchmarking."[219]

Both Huegin and Frontier agree that the post-modelling adjustments are unlikely to be sufficient to account for the different operating conditions.

No reasonableness check of results

A proper application of benchmarking would involve a reasonableness check of the results of the models. This is a process the AER should have conducted given the magnitude of the opex reductions which are unprecedented internationally[220] and the manner in which it has been applied retrospectively. Frontier argue that this fact alone should have prompted a more moderate response from the AER.

Frontier compared EI's modelled efficiency rankings with that determined by the Ontario Energy Board in its latest efficiency analysis completed in July 2014.[221] Frontier found that

> *"..the disparity in the efficiency ranking of the Ontarian networks, as between the OEB and the AER, casts strong doubt over the AER's results in relation to the Ontarian networks. Given that one Ontarian firm, Hydro One Brampton network Inc., sets the efficiency frontier in the AER"s analysis for the networks in all three jurisdictions, there would seem to be considerable doubt over the reliability of the AER's benchmarking analysis."*[222]

The AER's decision to apply base year opex adjustments recommended by the EI model in full from the first year of the period is not consistent with regulatory practice in other jurisdictions. Newbery, Huegin, PEG and

[218] Advisian, Review of AER benchmarking, January 2015, p4.

[219] Newbury, Expert Report, January 2015, p12.

[220] The PEG report outlines the history and practice of benchmarking internationally. PEG's survey did not identify any precedent that would support the approach taken by the AER in this draft determination.

[221] It is interesting to note that the OEB was assisted by PEG in this analysis.

[222] Frontier Economics, Review of the AER's econometric benchmarking models and their application in the draft determinations for Networks NSW: A report prepared for Networks NSW, January 2015, p62.

Frontier all point to the manner in which Ofgem acknowledges differences in modelled outcomes, and has applied a range of different models and weighted the results when determining adjustments to be made to businesses allowances. Newbery points out that the largest adjustment made by Ofgem in its most recent distribution price review was 11% and was justified by Ofgem on the basis of the length of time the networks have been subjected to comparative assessment and relative convergence achieved over that time.[223] In contrast, the AER has made adjustments three and four times as large in its first application of an untested model.

As a further comparison with Ofgem, in its most recent decisions Ofgem gave direct weight to the distributors costs in their analysis in addition to applying weights to its own models. In contrast, the AER has not applied any weight to the NSW DNSPs cost submissions and has simply substituted its own calculation of efficient costs using a single top-down benchmarking model.

In Norway, the regulator also applies a direct weighting to the distributors costs of 40% with the remaining 60% weighting being applied to benchmarking results.[224] No such balancing of the benchmarking outcomes with distributors costs has been made by the AER.

The Ontario Energy Board has also applied benchmarking in the context of price reviews but has not translated measured relative inefficiency between networks in a mechanistically into cost reductions. The OEB moderate the application of the model results by assigning businesses to tranches based on their relative performance and by applying significantly smaller adjustments to each tranche over time. In its last review, the largest adjustment factors applied as a stretch factor was 0.6% which is materially less onerous than the efficiency discounts proposed by the AER. Frontier points out in their report that the OEB views the stretch factors it sets as designed to encourage networks to become more efficient over time, and not punitive measures for inefficiency.

In contrast, the AER's proposal to cut opex by up to 40% for some distributors. When seen in dollar terms, the comparison is stark. For illustrative purposes, we take Ausgrid as an example, The application of a 0.6% stretch factor (applied to the worst Ontarian performer) equates to a 5-year revenue cut for Ausgrid of $73m[225] compared to the proposed opex cut for Ausgrid of $1,130m (effectively a revenue cut) proposed by the AER. In dollar terms the AER's reduction to opex is 15 times more onerous in revenue terms. The magnitude of the cost reductions applied by the AER cannot be seen as anything less than punitive and completely unreasonable when compared internationally.

In New Zealand, the Commerce Commission's consultant identified a substantial range (around 30%) in companies' efficiency but acknowledged the variable quality of the available data and residual uncertainties and to minimise risk reduced the range of relative productivity and profitability factors to –1, 0 and 1 per cent".[226] Using the example of Ausgrid once again, an X-factor of 1% applied to Ausgrid's 2014 proposal would equate to a reduction of proposed revenue of about $122m over 5 years. In contrast, the AER's proposed cuts to opex of $1,130m are nine times more onerous that that applied by the New Zealand regulator to the worse performers.

The imposition of cost reductions of the scale contemplated by the AER is without precedent in the countries that our experts surveyed. So too is the retrospective nature of the cost reductions. In contrast, our experts found evidence that regulators overseas acknowledge that changes to business operations take time and where stretch factors were applied or reductions to cost allowances imposed, they were applied in a way that reflected the regulator's judgements about the speed and extent to which a business can change its operations to reflect better performance. Newbery quotes from Meyrick and Associates who advised the New Zealand Commerce Commission in its 2004 electricity distribution networks price control and argued that it was unrealistic to expect lines businesses to be able to remove large productivity gaps in a short space of time.

[223] Newbery, p24.
[224] Frontier, p105.
[225] (proposed SCS revenue $12,189M x 0.6%)
[226] Newbury Report p26 which refers to Meyrick (2003, p63), *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996-2003*¸ a report prepared for Commerce Commission, Wellington New Zealand.

The AER has failed to apply simple sense checks to the results. For example, using the coefficients from the SFA model, the model suggests Endeavour should be allowed only 44% of the costs that would be provided to Citipower on a normalised basis. For Ausgrid, the rate is 60% of the equivalent Citipower costs.[227]

Due to the errors in the models and the data, Frontier recommend that the outcomes of the EI model be put aside and play no role in the AER's final determination. Huegin too consider that the results of the EI model are not a credible representation of base year expenditure and should not be used.

Based on this evidence we consider that the benchmarking analysis contains errors, and accordingly we have not revised our proposal for the AER's analysis

6.4.3. No reasonableness check of substitute opex allowance

The AER's substitute allowance for opex was derived from its benchmarking analysis. The AER derived an alternative base year using a benchmarking model developed by its consultant to identify the average opex of the top five 'frontier firms' in the analysis. The AER then applied a 10% increase to this level of opex to recognise factors that may increase the costs of providing services in our network. To calculate opex from the base year, they applied a rate of change factor derived from a formula. The AER's substitute allowance did not allow for any other increase in costs from the base year.

In deriving the substitute the AER has not considered our activities and costs in undertaking those activities, but rather developed a quantum of opex based on a single benchmark model. As noted in section 6.4.2 above, the benchmarking analysis is inherently limited and can never fully account for differences between DNSPs.

The AEMC has been clear that the AER has an obligaton to develop a reasonable substitute. In this case the test of reasonableness is whether the allowance is sufficient to enable a prudent and efficient operator to achieve the opex objectives. Rather than undertake a reasonableness check of its benchmarking analysis, the AER states:

> *"… we determine a service provider's opex allowance at the total level. We do not seek to interfere in the decisions a service provider will make about how and when to spend this total opex allowance to run its network, including the particular legal obligations it enters into to do so. The service provider is free to choose how to manage its allowance."*[228]

It is not sufficient to state that a DNSP is free to choose how to manage its allowance, without providing the DNSP with an allowance necessary to meet the objectives. We consider that assessing the component parts of our forecast would not necessarily amount to interference in how we spend our allowance. It is artificial to pretend that a holistic determination imposes any less of a fetter on the activities that a DNSP undertakes.

The individual circumstances and obligations of a business must be considered rather than constructing a hypothetical benchmark DNSP. In relying on benchmarking and high level analysis the AER has not understood the implications of its decision on safety, reliability and our ability to efficiently meet our obligations as a DNSP.

We sought advice from R2A Due Diligence Engineers in regard to safety impacts of the AER's decision (refer Attachment 1.09) and Jacobs Group Australia in relation to reliability and prudency. Please refer to Attachment 1.13 for its report on system capex and maintenance prudency assessment, and Attachment 1.14 for its report on reliability impact assessment.

R2A observed that:

[227] Advisian, Review of AER benchmarking, January 2015, p42.

[228] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 – Attachment 7, November 2014, p26

"If Endeavour Energy were to operate within the constraints of the draft determination, then in the short term, the number of safety incidents, especially to employees, is expected to spike due to the change in safety culture associated with this scale of staff loss. In the longer term, this analysis indicates that for the foreseeable threats to members of the public considered in this review, a doubling in fatalities from network hazards would most likely occur. In addition, the likelihood of the Endeavour Energy network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) is increased by around 60%".[229]

…The AER draft determination as it stands is, in effect, directing Endeavour Energy to disregard Endeavour Energy s own determination of what Endeavour Energy believes is necessary to demonstrate SFAIRP (so far as is reasonably practicable) *under the provisions of the Work Health and Safety Act 2011."*[230]

Jacobs expressed the following views:

"In our opinion, the AER does not appear to have apposite consideration of the impact that the revised expenditure levels have on the risk exposure of the NSW DNSPs."[231]

and

"…based on our review we consider that the AER has not duly regarded the associated risk profiles. In Jacobs' view the expenditure and risk profiles of the NSW DNSPs are directly linked. Thus, it would appear imprudent to reach a position on expenditure without considering risk profiles. From our understanding of the NSW DNSP's risk profiles gained throughout the course of this review we consider that, if imposed, the AER's Draft Determinations could potentially lead to a situation where the businesses are unable to effectively mitigate the risks associated with their network assets. Critically, in our review of the AER's discussions supporting the Draft Determination expenditure reductions we were unable to observe robust consideration of critical risk factors such as bushfires and public safety; where, in Jacobs' opinion the overarching thread focuses on costs versus reliability of supply." [232]

We consider that a reasoned decision maker would consider the risks that would arise from its substitute opex allowance. One means of doing this would be to assess the activities that the DNSP has identified as being requried to achieve the opex objectives. The AER should be able to identify if there is a particular activity or program that could be curtailed or limited while still enabling the DNSP to achieve the opex objectives. If all the activities are sound, the AER might then assess whether there is any efficiency that can be derived in delivering those activities. If the AER is unable to identify a source of inefficiency, it would then need to review its substitute allowance in that light.

[229] R2A, Endeavour Energy Asset/System Failure Safety Risk Assessment, January 2015, p4

[230] R2A, Endeavour Energy Asset/System Failure Safety Risk Assessment, January 2015, p4

[231] Jacobs, Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment, January 2015, p2

[232] Ibid. 118, p50.

6 OPERATING EXPENDITURE

6.5. Addressing substantive issues raised in the AER's decision

In undertaking its assessment method, the AER reviewed some specific elements of our proposal including labour practices, vegetation management costs and redundancy payments. The AER also reviewed the rate of change that could be expected from output growth, labour cost escalation and productivity.

Both the AER and the Deloitte Access Economics have selectively quoted from an article written by CEO Vince Graham and published in the Australian newspaper on 20 August 2014 to support their conclusions on the efficiency and productivity of (DNSPs) workforce.

The success of the NNSW Reform Program which commenced in July 2012, is clear evidence of the potential to progressively improve both the capital and operating efficiencies of Endeavour Energy. The continuation of that program is embedded in this revised proposal with committed labour productivity improvements of 21.6% and capital delivery efficiency improvements of 14.0% by the end of the regulatory period.

What Mr Graham's public comments also included was an acknowledgment of the difficulty in rolling back legally binding terms and conditions of employment embedded in certified agreements under the Fair Work Act.

> *"Removing or rolling back these conditions is challenging given the Fair Work Act. Progressively and safely contracting out the maintenance and capital activities of NSW Networks is one of the few means available to address these uncompetitive but legally binding union agreements".*

The legal reality is that certified enterprise agreements are a regulatory obligation on all employers determined by an Act of the Australian Parliament. The AER cannot simplistically conclude that obligations imposed by labour regulations and certified enterprise agreements can be unilaterally and retrospectively rescinded by their own economic regulation nor does NEL enable the AER to do so. In any case, the AER should have regard to the individual circumstances of a DNSP with regard to a realistic expectation of cost inputs.

Mr Graham's article was a transparent acknowledgment that continuing labour reform was necessary and set a pathway to progressively achieve that reform.

What is required is real and sustainable improvement in labour and capital efficiency driven by determined leadership in the long term interests of customers.

Our task is to assess whether the AER has raised matters that require us to make revisions to our forecasts. In the sections below, we discuss each of the issues raised by the AER and identify if we consider a revision is necessary to address the AER's reasons.

6.5.1. Labour cost efficiencies

The AER considered that our labour structure and costs are inefficient. The AER's opinion has been informed by its consultant's (Deloitte) review of labour and workforce management practices of the NSW service providers.

Deloitte found in respect of the labour costs incurred in delivering the capex program (labour-related capex), there is evidence to suggest that the expenditure and approach to resourcing the program was not consistent with that of a prudent or efficient service provider. In particular that all service providers seem to have relied too heavily on hiring permanent internal labour resources rather than using temporary external contractors to undertake the capex program, and that all service providers' labour-related capex was impacted by a unionised workforce that was relatively inflexible, high-cost and unproductive compared to their peers.

Deloitte considered the base year would not likely represent efficient costs because for much of the 2009-14 regulatory period it appears likely that the service providers' labour costs were impacted by:

- A relatively inflexible workforce with limited ability to innovate or respond to changing circumstances.

- Labour costs entrenched in Enterprise Bargaining Agreements (EBAs) which are well above peer costs.
- In some cases, poor management of labour costs – for example in relation to overtime.
- Union opposition to management attempts to reduce costs and/or improve productivity.

The AER considered this was supporting evidence driving some of the scope for its proposed base opex adjustments. It was satisfied that labour and workforce management contributes to a material source of inefficiency in opex in the 2012-13 base year (as supported in benchmarking analysis) for each of the NSW service providers.

Endeavour Energy has considered the findings of the AER and considered whether revisions are necessary to incorporate the substance of the findings. Attachment 6.01 sets out how we have undertaken the task of reviewing the AER's findings. The AER and Deloitte have not taken into account the information we provided to show that we have implemented significant efficiency programs in the 2009-14 period, and incorporated the impact of these efficiency programs into our opex forecasts for the 2014-19 period.

We have also relied on the expert opinion of CEG (Attachment 6.02) and K&L Gates (Attachment 6.03) in relation to the matters raised by the AER and Deloitte. Based on our review and the expert opinion of CEG and K&L Gates there is no information or analysis that has caused us to make revisions in response to the AER's findings.

We have however revised our proposal to incorporate the latest estimates on our labour costs for opex. This is based on updated information on our current workforce levels and efficiency programs we are implementing, which show a higher rate of employee productivity than forecast at the time of our initial proposal. Our revised proposal includes committed labour productivity improvements of 21.6% over the period; a reduction of 238 employees. Section 6.6 provides more detail on these revisions.

Efficiency programs implemented at Endeavour Energy

The AER and Deloitte have not sufficiently recognised the efficiency initiatives that we have put in place at Endeavour Energy over the 2009-14 period, and the efficiencies we have factored into our forecasts in the 2014-19 period.

Evidence submitted to the AER demonstrates that we responded to the incentive framework, by performing better than the efficient allowance set by the AER in the 2009-14 determination. We provided substantive evidence to demonstrate that our performance was based on efficiency activities we undertook in the 2009-14 period that resulted in us delivering a lower opex.These include:

- Workforce planning - Endeavour Energy has made significant progress in implementing more efficient delivery models. Using a staged transition, we have steadily moved from a heavily internal labour force to greater use of external resources. Approximately, 35% of our costs now relate to external contractors. Our decisions to use external resources have relied on prudent market testing, which has enabled us to identify areas of our business where we can outsource efficiently, and has also resulted in providing a source of competition for our internal labour.

- Robust wage negotiations with our employees - In an environment of significant demand for labour, we have managed strong and robust negotiations with our employees. Wage restraint has been the key to keeping labour costs lower over the period, together with the removal of inefficient allowances.

- Targeted and systematic efficiencies in our labour force - Under strong management leadership, we have implemented efficiency programs that aim to deliver more with less. The "C7" efficiency program was a bottom up plan to incorporate efficiencies into each aspect of our operations. Our "Challenge" and "Compete" programs led to significant reductions in our costs. The Networks NSW model has further elicited efficiencies by unlocking synergies across the three NSW DNSPs. In total these programs delivered opex effficiency savings of $185.2 million (2013-14 real) during the 2009-14 period.

- Exit plans - The cyclical nature of investment in the sector has led to a significant spike and dip in the resources required to deliver a safe and reliable network. We have responded to this environment through our use of flexible delivery models, by exiting employees when there are stranded assets, and via natural attrition which is higher as a result of employee recruitment freezes.

Our forecast opex for the 2014-19 program incorporated efficiencies we could achieve in the future, and these were incorporated into our forecasts for the 2014-19 period. These were based on granular assessments of our functions and activities. The AER has ignored this information in forming its conclusions. As noted in section 1.3.1 and explained in detail at Attachment 1.17, we have demonstrated that we are efficiently transforming our business structure.

Our efficiency programs are an extension of the progress we have made in the 2009-14 period, and incorporate the synergies that the Networks NSW model has unlocked across the three DNSPs. They reflect our goal of implementing sustainable efficiency savings over the 2014-19 regulatory period as these productivity improvements continue into the future. Table 6.2 shows the expected operating expenditure savings from the above strategies provided in our initial proposal.

Table 6.2: Efficiency programs incorporated into our 2014-19 forecasts

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
C7 Program	25.0	24.9	24.8	24.8	**24.8**	**124.3**
Project Challenge	21.7	21.8	21.7	21.8	21.8	**108.7**
Project Compete	6.2	6.2	6.2	6.2	**6.2**	**30.9**
Network Reform Program	5.6	8.7	8.7	8.7	8.7	**40.3**
Total Cost Reduction	**58.5**	**61.5**	**61.4**	**61.4**	**61.4**	**304.2**

In addition to this, the Network NSW reform will further unlock synergies across the three DNSPs resulting in a further $40.3 million reduction to opex in the 2014-19 period. Futhermore, our revised proposal includes labour productivity improvements of 21.6% over the period.

No evidence in Deloitte report

The AER in their draft determination highlighted the analysis that Deloitte were undertaking as important in helping the AER decide whether expenditure in the base year was an appropriate starting point for forecasting total opex that will reasonably reflect the opex criteria for the 2014-19 period.[233] The AER has taken the views of its consultant on face value without interrogating whether the basis for Deloitte's conclusions is sound.

The importance that the AER has placed on the Deloitte report is deeply concerning given the significant flaws in Deloitte's analysis render their conclusions unreliable.

It is worth noting before considering the contents of the Deloitte report the way the AER has used the findings with regards to the AER's use of benchmarking.

The proposed base opex cuts were an output of the AER's benchmarking analysis, the flaws in which are described above. The AER considered the findings of the Deloitte report as supporting evidence driving some of the scope of their proposed base opex cuts.[234]

[233] AER, Draft Determination Attachment 7: Operating Expenditure, November 2014, p7-87

[234] AER, Draft Determination Attachment 7: Operating Expenditure, November 2014, p7-90

The Deloitte report has a number of significant weaknesses. These weaknesses are fundamental enough to the nature of their analysis that the conclusions that Deloitte have reached cannot be supported. In their report, Deloitte concluded that we had labour costs entrenched in Enterprise Bargaining Agreements (EBAs) which are well above peer costs. This is despite their statement that "It is difficult to accurately identify differences in absolute wages costs between the DNSPs in different jurisdictions due to the use of different employee classifications and business structures."[235]

Instead of attempting to assess remuneration in a way that reflects the combined components of labour costs, Deloitte instead cherry picked provisions from the EBAs.[236]

Drawing a conclusion about labour costs based on a limited range of factors would seem deeply flawed regardless of the factors considered. Given that none of those factors considered in the Deloitte report were the base rate of pay, it would seem to be impossible to draw any conclusions on relative labour cost through comparison of EBAs.

EBA's are the result of negotiations and trade-offs between different elements of remuneration and workplace practices would be expected. This fact is recognised by the AER in its draft determination[237] on labour forecasts, but is ignored by both Deloitte and the AER with respect to labour costs.

The AER has previously not sought to review the outcomes of EBA negotiations:

> *"We note that the ongoing strength in wage increases in SP AusNet's recent EA outcomes appears to be in contrast to the expectation of easing in the overall competition for labour in Victoria over the 2014–17 regulatory control period. SP AusNet's EA outcomes, nevertheless, reflect the presumably free negotiations between SP AusNet, its employees and representative unions and we are not privy to these negotiations."*[238]

If Deloitte had undertaken some analysis of broader elements of remuneration they would have found that suggestions that we have higher labour costs than other DNSPs cannot be sustained.

One source of available evidence on labour costs is table 2.11 of the RIN, which required all DNSPs to identify labour costs per category of staff. Neither the Deloitte report nor the AER have commented on the data contained in this template although it was clearly developed to extract this type of information.

This available data suggests that the Deloitte report may contain an error of fact in asserting that our labour costs are higher than our peers. We reviewed the data in the RIN, and also re-checked the information we had provided to the AER in the RIN. Based on this analysis, our labour costs are in the low range of other DNSPs[239] in Australia, and lower than most of the businesses the AER included as "frontier" performers. While we remain cautious about the quality and comparability of the data provided in this template, we note that this evidence available to the AER does not suggest that our labour costs are the key driver of observed differences in benchmarking performance.

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[235] Deloitte, NSW Distribution Network Service Providers Labour Analysis, 17 November 2014, p31

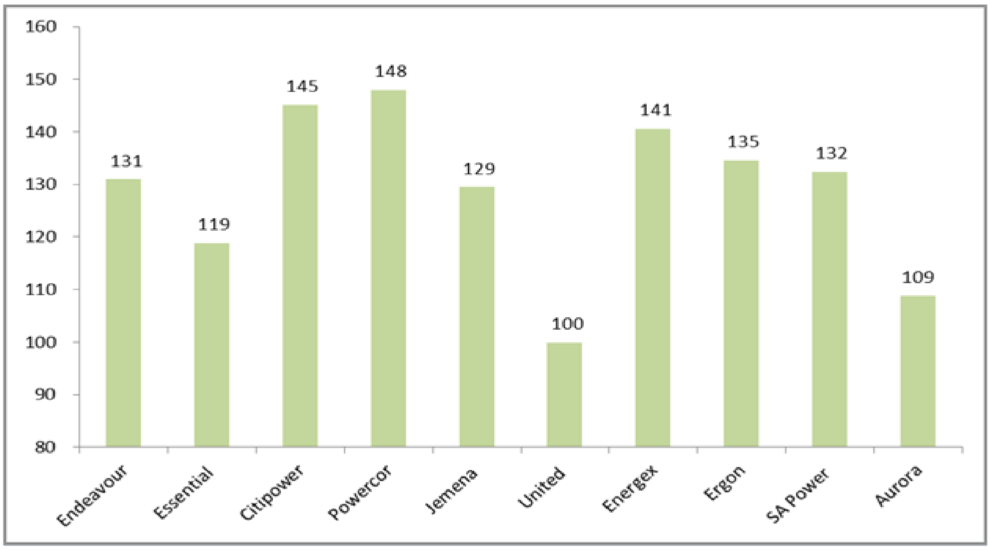
[236] As part of their analysis Deloitte have compared these provisions to the Industry Award. A comparison of this type reflects a deep misunderstanding of the nature of the Award compared to the EBA as such a comparison would suggest wrongly that EBAs should contain the provisions no higher than contained in the award.

[237] AER, Draft Determination Attachment 7: Operating expenditure, November 2014, p7-151

[238] AER, Final Decision SP AusNet Transmission determination 2014-15 to 2016-17, page 82.

[239] We note that we have made certain adjustments to information provided by Ergon and Aurora to rectify an apparent anomaly with decimal point which overstated its labour costs by a multiple of 10.

Figure 6f: Average labour costs per employee



NNSW engaged CEG to undertake analysis of labour costs compared to other DNSPs. The CEG report[240] attached to this revised proposal found that our labour costs were comparable to our peers. This outcome is despite the higher labour costs experienced more generally outside the energy industry in NSW when compared to Victoria, Queensland, Tasmania and South Australia.

Deloitte's analysis stems from an assumption that outsourcing is efficient in all circumstances, and therefore relative efficiencies can be attributed to differences in outsourcing rates. Deloitte does not provide evidence for this assumption.

While the Victorian DNSPs outsource more than the NSW DNSPs the level of outsourcing is clearly not as disparate as presented by the numbers quoted by Deloitte, due to the majority of Victorian outsourcing being to related parties. A further aspect that appears to have been overlooked by Deloitte is a number of Victorian EBAs contain provisions that restrict outsourcing to where the engaged company applies wages and conditions which are no less favourable than those contained in the DNSP's EBA.

The more complete analysis by CEG directly moderates the Deloitte finding that our EBA provisions are more generous than those present in other states.

Again Deloitte seems to have cherry picked provisions from within the EBAs to support its conclusion. As part of their analysis on all relevant provisions, K&L Gates[241] analysed these provisions. Their findings, which contradict those of Deloitte, may be a reflection of their greater experience in industrial relations for electricity networks.

Attachment 6.01 highlights further key weaknesses with the analysis in the Deloitte report, and show that it cannot be relied on to inform the AER's assessment:

- Deloitte's analysis stems from an assumption that outsourcing is efficient in all circumstances, and therefore relative efficiencies can be attributed to differences in outsourcing rates. Deloitte do not provide evidence for this assumption. It is clear to us that outsourcing may be inefficient in a number of instances as can be demonstrated by our prudent market testing processes in the 2009-14 period.

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[240] CEG Report titled "Labour unit cost – review of Deloitte report" provided as Attachment 6.02.

[241] See K&L Gates report titled "Comparison and Analysis of Enterprise Bargaining Agreements for Distribution Networks", January 2015, p3.

Comprehensive outsourcing to an overheated construction market during the 'mining boom' was not an efficient capital strategy and yet is implied by the Deloitte report as being a preferred strategy.

- In any case, Deloitte has ignored evidence which shows that Endeavour Energy implemented significant outsourcing in the 2009-14 period. As noted above, approximately 35% of the operating and maintenance work program is completed by external contractors.
- While the Victorian DNSPs outsource more than the NSW DNSPs, the level of outsourcing is clearly not as disparate as presented by the numbers quoted by Deloitte.

Endeavour Energy accepts there are aspects of our current enterprise agreements that do need to be addressed to improve labour efficiency including superannuation and long service leave entitlements. The AER however, do need to undertake more comprehensive labour cost and labour productivity benchmarking before relying on Deloitte's analysis to determine operating expenditure, The two essential components in comparing labour costs are the rates paid per employee and the number of employees needed to undertake the comparable tasks. The complexity of calculating the cost of multiple and diverse allowances across the industry in addition to award rates, provisions and overtime adds to the challenge faced by the AER.

6.5.2. Increased costs for vegetation management

In our proposal we noted that our forecast costs for vegetation management would be higher than the actual costs incurred in the 2012-13 year. The AER has made two downward adjustments to our proposed opex for vegetation management.

Firstly, the AER reviewed our 2012-13 base year expenditure, and found that our overall opex was higher than the benchmark, and that our vegetation management costs in particular were higher than our peers. The AER substituted a base year for total opex, which implies a reduction to vegetation management as part of the overall cut.

Secondly, the AER considered that our proposed increase to vegetation management constituted a 'step change' under its assessment method. The AER considered that the step change should not be included in its alternative estimate of opex based on three key reasons:

- Endeavour Energy did not face new regulatory obligations in relation to vegetation management. The AER considered an efficient level of base opex already provides a sufficient allowance for a prudent and efficient service provider to meet its existing regulatory obligations.
- Endeavour Energy did not satisfy the AER of a need for additional vegetation management expenditure.
- The AER considered that Endeavour Energy derived an EBSS carryover benefit from its lower vegetation management expenditure in the 2009–14 regulatory period. The AER stated that consumers benefit from the EBSS when opex savings are passed through to consumers. It noted that under Endeavour Energy's approach, we proposed to capture the EBSS benefits arising from lower expenditure on vegetation management in 2009–14 but does not propose to pass the lower opex through to consumers. The AER considered this was contrary to how the EBSS is intended to operate.

We have reviewed the AER's decision when assessing whether any revision to our initial proposal is required to address the reasons provided by the AER. Based on this review, we consider that the AER's analysis has not identified an issue with our proposed vegetation management costs, and accordingly we have not revised our proposal in response to the reasons.

As noted in section 6.6 we have however, revised our proposal for vegetation management to incorporate latest information on the level of activity we need to undertake on vegetation management. Attachment 6.04 provides further information on how we have considered the AER's draft decision.

Before addressing the AER's particular issues, we note that vegetation management is a critical activity undertaken by a DNSP. The importance of prudent vegetation management has been put into the spotlight as a result of catastrophic damage of bushfires across the nation. Prior to these events, the industry may not been paying sufficient regard to the public safety implications, with these issues arising from insufficient regulatory allowances. The Royal Commission into the 2009 black Saturday noted that 173 people had died in the bushfires. The Commission stated:

> *"Victoria's electricity assets are ageing, and the age of the assets contributed to three of the electricity-caused fires on 7 February 2009 - the Kilmore East, Coleraine and Horsham fires. Distribution businesses' capacity to respond to an ageing network is, however, constrained by the electricity industry's economic regulatory regime. The regime favours the status quo and makes it difficult to bring about substantial reform. As components of the distribution network age and approach the end of their engineering life, there will probably be an increase in the number of fires resulting from asset failures unless urgent preventive steps are taken.*
>
> *The Commission considers that now is the time to start replacing the ageing electricity infrastructure and to make major changes to its operation and management. The seriousness of the risk and the need to protect human life are imperatives Victorians cannot ignore."*[242]

Given the increased awareness of this issue, we consider the AER has taken an unreasonable approach to reviewing our proposed vegetation management costs. The AER's assessment method involved a superficial review of benchmarking data, and an approach to reviewing our proposed increase in costs relative to the base year that failed to recognise that we are not meeting our current regulatory obligations. We discuss each of these points below.

AER's comments on benchmarking

The AER has purported to undertake a comparison of our benchmarking costs relative to other DNSPs in the NEM. It has formed a view that we have high costs relative to United Energy, and provided a graph which showed our relative costs on a customer density basis. The AER has not provided any further evidence, with its entire focus being on Essential Energy.

We have reviewed the data to establish whether the analysis establishes a need to revise our proposal. We consider that the AER's analysis is highly flawed and does not show a reasonable basis for forming a conclusion that our vegetation management costs, which are all market based, are inefficient. Indeed we consider that this reveals broader weaknesses in the AER's benchmarking approach to reviewing our proposal.

In Attachment 6.04 we make the following observations. Firstly, we note that the AER has not identified the standards that other DNSPs may apply, or if they are achieving compliance with those standards. In addition some of the scope of vegetation management activities performed in the franchise areas of these lower ranked DNSPs are in fact performed by local councils. We therefore consider it unreasonable to compare our performance to these DNSPs, and to have our costs reduced to their level.

Secondly, the AER has used average data from 2009 to 2013. This includes a time period when Victorian DNSPs were significantly underspending on vegetation management. Since the Royal Commission, Victorian DNSPs have been increasing levels of spend to meet a prudent standard. We consider it is highly unreasonable to compare our forecasts on this time series, given that a business such as United Energy (our direct comparator in the AER's analysis) have more than tripled spending between 2009 to 2013.[243]

[242] Royal Bushfires Commission Victoria, Final Summary – 2009 Victorian Bushfire Royal Commission, July 2010, p12.

[243] The source of this data is the response provided by each Victorian DNSP to the AER's category analysis (template 2,1 row 32)

Table 6.3: Vegetation management costs of Victorian DNSPs ($m, Nominal)

($m, Nominal)	2009-10	2010-11	2011-12	2012-13	2013-14	% change between 2009 and 2013
Citipower	0.960	1.014	2.601	4.908	2.308	140%
Powercorp	14.001	9.959	26.901	40.520	45.144	222%
Jemena	0.884	1.086	2.291	4.629	4.405	398%
SPAusNet	23.567	21.490	24.487	32.686	38.883	65%
United Energy	4.057	4.972	9.895	15.026	14.029	246%

Thirdly, the AER's method of normalising costs by using customer density does not adequately reflect differences in operating conditions that DNSPs operate. The AER has dismissed the view put forward by Ausgrid that NSW has topographical features that increase our costs of mitigating bushfires. The AER has unreasonably pointed to data which shows that Victoria have more bushfires, and therefore concluded that this means our costs should be lower. Quite clearly, the AER should have sought further questions on whether the data demonstrates whether bushfires were related to legacy vegetation management or asset management issues in Victoria.

AER's analysis of step changes

We consider that the AER's approach to review our proposed vegetation management costs under its test of a step change was overly narrow, and did not enable it to make a proper assessment against the opex criteria. The test of a step change presumes that the base year costs already achieve the opex objectives. In this case it was clear that the issue related to a non-compliance issue.

In our response to the AER's questions on 21 July 2014 , we identified that Endeavour Energy had been progressively addressing non-compliance issues with meeting the compliance standards in the ISSC 3. We showed that prior to the 2009- 2014 period, compliance levels to vegetation management standards were below acceptable levels. From 2009 onwards, we have progressively been aiming to increase our compliance levels to as close as practicable to 100%. This focus was due in part to the findings of the Victorian Bush Fires Royal Commission.

Since 2009 we have strictly enforced compliance to standards in managing our vegetation contractors. A key issue we have faced is ensuring that our external contractors deliver to the standard. As with any contract, under performance results in the contracted amount not being paid. This is a key reason why our vegetation management costs were under the allowance determined by the AER in the early years of the 2009-14 period. Any contractor under performance against standards resulted in under-spend. We have been working with our external contractors to ensure that we move towards compliance. By the 2012-13 base year we had achieved standard compliance of 76%.

With this information in front of the AER it should have been clear that the additional expenditure was to address a non-compliance issue with an existing regulatory obligation. It would have also been clear to the AER that our costs were efficient given that the activity we performed was to meet a specific standard, and our delivery mode was based on an open and competitive tendering process in a mature external market.

We consider that if the AER had undertaken its task in a proper manner it would have been satisfied that the proposed costs were the efficient and prudent level of expenditure to achieve our regulatory obligations. In this respect, it was clear from the information in front of the AER that:

- Our proposed costs were based on achieving our regulatory obligations (opex objective 2). The Electricity Supply (Safety and Network Management) Regulation 2014 states that we must have a safety management system in place that is in accordance with AS 5577 or with any other code or standard that the Secretary may, by written notice given to the network operator, nominate. In this respect we must comply with the Code of Practice: Electricity transmission and distribution asset management. This nominates the standard ISSC 3 to which we must comply.
- The ISSC 3 is widely recognised as 'best practice', and clearly specifies the clearance distance for each type of tree for individual voltages. Our internal standards simply adopt the elements of the standard that are relevant to our network.
- Our forecast of costs were based on market tendered delivery of vegetation management. Our process for procuring external delivery relies on open and competitive tendering processes, and is clearly aligned to the standards we are requried to achieve. We consider this provides a level of satisfaction as to the efficiency of our costs.

Implications on Insurance Arrangements as a Result of Lower Vegetation Activity

Our vegetation management expenditure is based on achieving compliance with our regulatory obligations, delivering public safety outcomes and prudent risk management. Endeavour Energy, Ausgrid and Essential Energy have jointly insured "common risks" for a number of years including bushfire liability insurance. A key platform for our ability to obtain cost effective insurance for this catastrophic risk is the prudent risk management practices we employ, particularly in relation to vegetation management.

Aon Risk Solutions were engaged to provide advice on potential implications to insurance premiums arising from a reduction in preventative asset management particularly vegetation management expenditure. Aon's advice is at Attachment 1.10 and states:

> *"There is no doubt that a reduction in preventative asset management such as vegetation controls would result in severely increased premiums, current premium discounts enjoyed by NNSW against insurer technical rating structures would be reduced or withdrawn."*
>
> *Based on the findings, analysis and considerations contained within this Report, Aon estimates that under current insurance market conditions and without further losses from bushfire liability accruing to the specialist insurance market, potentially estimated and unverified composite premium costs representing an increase of up to c.125% over the current 2014-2015 insurance position."*[244]

During the 2014-15 renewal we evidenced withdrawal of a number of underwriters for Australian bushfire liability insurance. This follows the withdrawal of participating US underwriters in 2012.[245]

> *"If underwriters become exposed to bushfire losses arising from insured contingencies occurring across Australia or internationally, say from increased claims arising from a poor bushfire or wildfire season, then market conditions could rapidly deteriorate.*
>
> *In such circumstances, and given the past positive differentiation that NNSW has effectively conveyed to markets demonstrated through effective risk management regimes including vegetation management initiatives, faced with a more exposed risk profile the NNSW insurers could seek other opportunities in utilisation of their capacities and simply walk-away.*
>
> *This holds the potential to leave NNSW in an untenable, effectively partially or even largely uninsured position at some point over the course of the next 5 years."*

The outcome of this review highlights that Endeavour Energy may not be able to obtain coverage to the limits we require which would expose us to uninsured risks. This review also highlights that the market would see us not managing our risks prudently.

[244] AON, Insurance Advice Report, January 2015, p5.

[245] AON, Insurance Advice Report, January 2015, p5

6.5.3. Redundancy costs

Our proposal included forecast costs relating to termination payments for redundant employees. The AER considered that our forecast redundancy costs do not meet its criteria of a step change. The AER concluded that the cost did not relate to a change in obligations, or from a consequence of changes to capex. The AER considered that decisions to re-structure the business were internal decisions that we had undertaken, and therefore should be absorbed by the business. We do not accept the AER's decision:

- The AER's mechanical use of a 'step change' definition has led the AER to incorrectly reject costs that meet the opex criteria of efficiency and prudency.[246] The term 'step change' is not used in the Rules, and is only a concept that the AER has developed to guide its decision making. The AER has not demonstrated that the concept can completely capture the decision making criteria in the Rules.
- The redundancy costs meet the criteria of efficient costs. Termination payments relate to the excess labour resulting from efficiency programs. The efficiency programs have led to significant reductions in our opex that far outweigh the costs of redundancies, and provide a net benefit to customers. It would be unreasonable for the AER to incorporate efficiencies, but not allow the costs of the re-structure.
- We also have regulatory obligations to provide redundant employees with termination payments under existing awards certified by the Fair Work Commission in accordance with the Fair Work Act. It is entirely unreasonable to state that these are costs should be absorbed by the shareholder.

6.5.4. Change factors

Output growth

In our initial proposal, we proposed an increase for output growth of $181 million. Based on its own formula comprising ratcheted maximum demand, customer numbers and curcuit length, the AER consider that our proposed growth factor was too high. The AER subsequently substituted its own output growth factor which has been difficult to reconcile based on the data provided as part of the AER's draft determination.

We have considered whether the AER's output growth factor is a better basis for determining our increase in opex from the base year. Based on our review, we consider there is no basis for revising our proposal. The AER's review of our growth factor failed to recognise that we included an increase in maintenance related to our proposed capex program. Similarly, the substitute calculation used by the AER does not contemplate this as a driver of costs.

We consider that this issue underlies the shortcomings in the AER's assessment method, as it does not enable a proper review of our proposed costs against 6.5.6 of the Rules. Our proposal noted that opex-capex substitution possibilities are a relevant opex factor, and that this is a fundamental aspect of a prudent forecast method. We showed that our proposed costs had included an increase of maintenance costs to reflect the expected deterioration in our assets as a result of deferrals in our replacement capex programs.

For this reason, we consider that our initial proposal had accurately captured a relevant change factor, and that the AER's assessment should have considered this in greater detail when reviewing our proposal.

Real cost escalation

We have revised our proposal to incorporate the AER's draft determination on labour cost escalation. This is discussed further in section 6.6 of this proposal.

[246] We note that we had previously raised issues with the AER as part of Networks NSW response to the Forecast Expenditure Assessment Guidelines.

Productivity

The AER has applied a productivity factor of zero when assessing the forecast of opex from the base year. We have reviewed the AER's decision to assess whether we need to revise our proposal in response to the AER's decision.

Our view is that our forecast method had already captured productivity growth through our efficiency programs. We note that our regulatory proposal incorporated efficiencies in the 2014-19 program related to both our internal and Networks NSW programs. To the extent that productivity had been captured at a granular level of detail we consider that there is no need to revise our forecasting method to capture a general productivity dividend.

We consider that the AER's decision to mechanically include a productivity dividend raises deeper concerns with the manner in which it has assessed our proposal. Our view is that the AER should engage with the information provided in our proposal to asssess whether our proposal for 2014-19 represented the efficient costs of achieving the opex objectives.

Had the AER undertaken this assessment, it would have found that our proposal incorporated productivity improvements well in excess of the industry average based on the AER's benchmarking. On this basis it should have been satisfied that the forecast opex in each year of the 2014-19 regulatory period was efficient, and satisfied the opex criteria.

6.6. Revisions to our proposed opex

As noted in sections 6.4 and 6.5, we have reviewed the AER's decision in a great level of detail to assess whether we need to revise our proposal for the issues raised. During our review we identified deficiencies with the AER's assessment method which has not led to a proper assessment of our proposal under the Rules. We also examined the substantive issues raised by the AER concerning aspects of our proposal such as vegetation management, labour inefficiencies and redundancy costs. We found that the AER had not applied a proper method to review these costs, and that we remain satisfied that our methods satisfied the opex criteria.

In reviewing the AER's reasons, we also examined whether there was any new information that impacts on our revised proposal. We have revised our proposal to incorporate the latest information on expected changes in employee numbers as a result of efficiency programs, vegetation management costs, and labour cost escalators.

6.6.1. Revisions to our initial proposal

We have revised our proposal for matters that the AER have reviewed in making its decision. Based on these reviews, we have been mindful of examining the latest data and information available since submitting our proposal. We have made the following revisions in light of this information:

- The AER considered that our vegetation management costs should not be accepted. Upon further review, we found that our costs should be higher than proposed by the AER as a result of actual 2012-13 data relating to the costs of complying with our standards.
- We have examined whether our latest information reveals any change in our staffing levels as a result of efficiency programs we are undertaking. As a result of this analysis we are proposing progressive improvements in labour productivity of 21.6% by the end of the regulatory period; a reduction of 238 employees.
- Productivity savings of 21.6% by the end of the regulatory period has also been applied to associated non labour operating costs. Contracts for goods and services, including vegetation service contracts, have been escalated consistent with the terms of the contract. Fleet costs have been reduced proportionally with labour productivity improvements.
- We have used the AER's draft decision for labur cost escalators.

6 OPERATING EXPENDITURE

Our revised proposal for standard control services operating expenditure for the 2014-19 regulatory period is $1,467.4 million, inclusive of debt raising and DMIA, as shown in Table 6.4 below.

Table 6.4: Forecast operating expenditure over the 2014-19 regulatory control period

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Network operating costs	22.5	24.3	23.3	22.5	21.7	**114.3**
Inspection	32.1	30.8	30.6	30.5	30.4	**154.4**
Maintenance and repair	63.0	65.0	63.1	61.6	60.3	**313.0**
Vegetation management	78.4	88.8	88.5	88.7	89.1	**433.6**
Emergency response	47.5	47.5	46.0	44.9	43.8	**229.7**
Network maintenance	19.6	16.5	14.9	14.6	14.2	**79.8**
Customer service	4.6	5.1	4.9	4.8	4.6	**24.0**
Other operating costs	18.2	20.7	20.3	20.0	19.7	**98.8**
DMIA	0.6	0.6	0.6	0.6	0.6	**3.0**
Debt raising costs	3.2	3.3	3.4	3.4	3.5	**16.8**
Total operating expenditure for PTRM	**289.8**	**302.7**	**295.5**	**291.6**	**287.9**	**1,467.4**

Note: numbers may not add due to rounding

6.6.2. Why our proposed opex better meets the opex objectives and criteria

We do not consider the revised forecast opex is materially different from our initial proposal, with the exception of our vegetation management costs and the incorporation of further efficiencies. Our changes mainly relate to updated information on our efficiency programs and labour cost escalators, and provide a more accurate forecast of the costs of complying with our vegetation management standards.

As such, the reasons outlined in the initial proposal (outlined in section 6.1) as to why we consider our forecast satisfies the opex objectives, criteria and factors remain valid. As outlined in that section (Attachment 0.03) to our initial proposal and the 'meeting the Rules' section of our initial proposal provide further detail as to why we consider this to be the case.

In particular we consider that our forecasting method and assumptions better satisfy the opex criteria relative to the AER's substitution approach. Our forecast methodology used actual costs in 2012-13 as a starting point to derive an efficient forecast of opex. We demonstrated that we had responded to the incentives designed by the AER to reduce our opex to levels well below the efficient allowance set by the AER in its 2014-19 determination. We then considered our change factors relevant to our circumstances including incorporating the level of efficiencies we could achieve in the 2014-19 determination. The methodology was prudent in our circumstances, and resulted in an efficient forecast of opex for the 2014-19 period.

In contrast, the AER's substitution method relied on information that was divorced from our forecast method, and which relied on a high level benchmarking model. Under the Rules, the AER is open to apply any method it wishes to derive a substitute opex. However, its decision must consider the opex criteria, be without error, and be reasonable in the circumstances. Our view is that the AER's substitute approach did not enable it to undertake a proper examination of whether its substitute amount satisfies the opex criteria. We consider that the AER should have considered:

- The activities we perform that incur operating costs. This would identify whether the activities are requried to achieve the opex objectives.
- Whether the costs involved in delivering that activity are reasonable and reflect the efficient costs of doing so, with regard to a DNSP's circumstances.

The AER's benchmarking analysis did not address the activities we perform, nor did the AER's review of our regulatory proposal. The only area where the AER has identified a deficiency in the actual opex we incurred in 2012-13 has been labour cost efficiencies and vegetation management.

In respect of labour cost efficiencies we have demonstrated that there is no evidence to demonstrate that our costs are inefficient relative to our peers. Indeed the only available evidence suggests that our labour costs are at the median range. In any case, the AER has not recognised the regulatory obligations imposed by an enterprise agreement certified by the Fair Work Commission under the Fair Work Act.

The AER's review of our vegetation management costs in 2012-13 has ignored data we provided which show that we did not meet compliance in that year. The AER should have drawn the conclusion that we required more expenditure rather than less. Instead the AER has relied on highly flawed benchmarking analysis which used a time series where the 'frontier' DNSPs had been well below prudent compliance levels. To compare our costs to these DNSPs was unreasonable.

The AER's substitute amount provides approximately 22.8% less than what we proposed. Had the AER undertaken proper analysis it would have understood that we could not continue to provide the same level of service to customers as we currently do, and this would result in us not meeting our regulatory obligations. Without the ability to significantly alter the wages we pay our employees, this would mean we have to simply perform a lower level of activity than we currently do. This has practical implications for safety and reliability outcomes.

At a high level, the magnitude of the impact of the proposed opex cuts on reliability performance has not been adequately assessed by the AER. Unmanageable reductions to opex and the corresponding impacts to staffing levels will result in a worsening of reliability performance. The expected impacts are:

- Reduces capacity to respond to network faults leading to longer restoration times, particularly on busy high fault event days. This is as a result of direct staffing level reductions as well as secondary effects such as potential depot rationalisation.
- Higher frequency of equipment failure based outages due to extensions of maintenance inspection cycles away from optimal FMECA/RCM identified maintenance intervals.
- Reduces overall business efficiency through greater unplanned/emergency work taking resources away from more efficient planned maintenance activities.
- Reduces capability to perform detailed engineering analysis at the planning stages.

High level analysis and modelling of the impact of the AER draft determination opex cuts on reliability performance has been conducted for Networks NSW by consultants Jacobs (Attachment 1.15) The analysis focused primarily on increased failure rates due to extended maintenance cycles of 11kV and 22kV overhead distribution assets (poles, crossarms and wires) and response times.

The Jacobs modelling suggested that Endeavour Energy would experience a significant deterioration in SAIFI and SAIDI over the regulatory period. This modelling was time constrained, considering only a subset of possible impacts and therefore represents a conservative estimate of reliability deterioration. The actual deterioration due to the proposed opex cuts is expected to be worse if the full range of impacts is considered. In the dot points below we show how reductions in allowances for our core activities may lead to increased risk of outages and safety incidents, and increase costs for customers in the long term:

- **Vegetation management** – Lower opex means that we would need to reduce our compliance levels with our standards, despite information showing that we are currently trying to address non-compliance issues. In turn, this would lead to a far higher risk of bushfires that can have devastating impacts on human life and property. It also increases the risk of other fires on the network, and increases the frequency and duration of outages.
- **Emergency response** – Lower opex would increase the amount of time it takes to respond to outages on the network. This would impact the customer through increased interruption times which will impact our current life support customer population of more than 17,600. For businesses this would involve higher economic costs from outages.
- **Inspections, preventive maintenance** – Lower opex will increase the risk of outages on the network, and increase the probability of safety incidents. We have highly sophisticated maintenance planning tools (FMECA RCM) which has the objective of optimising maintenance periods to strike the best balance between asset performance and maintenance costs. Reducing maintenance expenditure will increase asset failure rates, leading to greater safety hazards, poorer reliability and potentially earlier asset replacement. This delivers worse outcomes to customers in the short term and and higher costs to customers over the medium to longer term.
- **Corrective maintenance** – Lower opex means that we will be put in the position of spending a greater proportion of maintenance effort responding to asset failures and carrying out corrective maintenance. This, by definition, involves a response after the safety or reliability impact of asset failure has been realised resulting hazards and interruption time to customers, as well as more inefficient emergency deployment of staff.

In relation to the above two points, Jacobs have noted:

> *"The FMECA/RCM method analyses a variety of factors to provide a transparent view of the risks associated with different scenarios. As a result, informed decisions can be made as to the optimised inspection and maintenance regimes, considering cost, safety and reliability. In quantifying risk the tool analyses a breadth of direct and indirect costs in conjunction with probabilities and consequence costs. In Jacobs view significant reductions to system opex would disrupt the optimised programmes, which, while potentially reducing opex in the short term, would lead to higher overall costs over the medium to longer term. This would not be a prudent outcome for the NSW DNSPs."*[247]

- **Operating and controlling the network** – Lower opex would increase the risks of safety and reliability incidents as a result of lower resourcing in the control room and associated switching activities. It may also impact our ability to respond to faults in a timely manner, and reduce our effectiveness in planned scheduling of outages. We note that this would not be an area where we could reduce opex, due to the significant risks to employee and public safety.
- **Support expenditure** – Lower expenditure will result in reduced effectiveness in supporting our core operations. We note that we have already made significant reductions in these areas, and that any further cut would jeopardise our ability to meet our corporate obligations in respect of financial reporting, public and worker safety and environmental safety. We would also need to reduce our call centre responsiveness to our customers.

As such, we consider that our revised total of forecast opex better satisfies the opex criteria relative to the AER's substitute amount.

[247] Ibid. 118, p 47.

6.6.3. Immediate adjustment to the AER's forecast opex not appropriate

We consider that the AER should accept our revised forecast opex for the reasons discussed above. However, if the AER was to determine that significant reductions in our forecast opex of the size contemplated by the AER's draft determination should be implemented, then we consider that the AER is required to implement it, and provide a forecast opex, that provides for a realistic forecast of Endeavour Energy's actual costs while incentivising efficiency reductions over time in a realistic manner.

The AER must determine a forecast opex that reasonably reflects the operating expenditure criteria having regard to the operating expenditure factors under clause 6.12.1(4). The operating expenditure criteria that must be reasonably reflected are:

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

The operating expenditure criteria and the requirement for the AER to consider the individual circumstances and actual costs of Endeavour Energy are discussed above.

Given the inherent requirements on Endeavour Energy to supply electricity safely, legally and reliably, any reduction in opex must be carefully planned and managed. This careful management and planning has been reflected in the efficiency programs that Endeavour Energy and the broader Networks NSW's group of businesses have adopted in the last regulatory period. These efficiency programs are delivering substantial savings that are reflected in this revised proposal.

Endeavour Energy is currently subject to the allowed revenue (and opex) under the transitional determination and, prior to that was subject to the allowed revenue (and forecast opex) under the regulatory determination for the 2009-14 regulatory period. Any sudden reduction in allowed revenue caused by a reduction in forecast opex such as that contemplated by the AER's draft determination has the potential to jeopardise the safety and reliability of Endeavour Energy's network as described above. A prudent operator would not take this risk given the potential consequences as explained in the COO Statement at Attachment 1.08.

However, it would also be inconsistent with both the operating expenditure criteria and the national electricity objective for the prudent operator for shareholders to bear the cost of the significant reduction in forecast opex because doing so may cause significant financeability risks to Endeavour Energy, which would reduce its viability and the incentives and ability to invest in its network.

To avoid these risks, the operating expenditure criteria require the AER to determine forecast opex that (amongst other things) reasonably reflects the realistic cost inputs to achieve the operating expenditure objectives. It is not realistic for Endeavour Energy to instantaneously reduce many of its costs, such as its labour costs under its EBA, because it is legally prevented from doing so. These costs have been permitted by the AER and incurred by Endeavour Energy through the last regulatory period. Any adjustment to these costs to incentivise efficiency must also reflect the time that it would realistically take Endeavour Energy to implement them.

7 ALLOWED RATE OF RETURN

Summary

We have carefully reviewed the AER's draft determination on the allowed rate of return and the AER's reasons for it. However, we have not proposed any material change to the cost of capital in our revised proposal. Our revised proposal incorporates a rate of return on capital of 8.85 per cent. Our revised proposal supports the immediate adoption of a 10 year trailing average approach to calculate the return on debt that is consistent with the efficient debt management practice of Endeavour Energy and a return on equity that takes account of all relevant evidence.

In this chapter, we have set out our revised proposal on the allowed rate of return. In developing our revised proposal, we have fully considered both the AER's draft determination and its final rate of return guideline (guideline). We have also outlined areas of the AER's draft determination and guideline that we agree with and those that we do not agree with. Where we disagree with the AER's draft determination or its guideline, we have explained our reasons for this.

- We propose a rate of return of 8.85%, commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Endeavour Energy over the 2014-19 period. The revised rate of return has been developed to promote long term stability both for customers and equity holders. This is well below the allowed rate of return for the 2009-14 regulatory period of 10.02% and reflects reductions in financing costs since the previous determination.
- Our proposed rate of return approach for setting both the allowed cost of debt and the allowed return on equity would provide return profiles commensurate with what is required to attract investment in long-lived electricity network assets.
- We propose an allowed return on debt of 7.98%, which has been calculated consistent with the 10 year trailing average approach set out in the AER's final rate of return guideline. This estimate is based on bond yield data for broad BBB[248] rated Australian corporate bonds on issue from 1 January 2004 to 31 December 2013. This is lower than the allowed return on debt of 8.82% set in the 2009-14 period and reflects the reduction in the benchmark efficient costs of debt under the staggered portfolio approach.
- In the draft decision, the AER considered that (subject to a lengthy debt transition) the allowed return on debt should be estimated using a 10 year trailing average approach that would be subject to annual updates throughout the regulatory control period. With the exception of the transitional arrangements and the choice of data service provider, this is consistent with Endeavour Energy's initial proposal. We agree with the trailing average approach for setting the allowed return on debt, but we do not agree with the AER's proposed debt transition, choice of data service provider and its assumed benchmark efficient credit rating.
- The application of the AER's proposed debt transition is inconsistent with a number of the revenue and pricing principles in section 7A of the NEL. In particular, the AER's proposed transition would not, over the 2014-19 period, provide us with a reasonable opportunity to recover at least the efficient costs of debt finance, nor give rise to prices that would allow for a return commensurate with the regulatory and commercial risks involved in providing direct control network services.

[248] We note that due to the limited number of long dated BBB rated bonds, the RBA and Bloomberg have typically relied on bonds rated in the broad BBB band, i.e. BBB-, BBB and BBB+.

7 ALLOWED RATE OF RETURN

- The AER's proposed transition approach would not operate to minimise any difference between the allowed return on debt and the return on debt of a benchmark efficient entity with a similar degree of risk as that which applies to Endeavour Energy. It would also mean that the benchmark efficient approach for setting the allowed return of debt (the trailing average approach) would not be fully implemented for 10 years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis.
- Endeavour Energy has historically issued debt on a benchmark efficient staggered portfolio basis and the AER's proposed transition would significantly under-compensate Endeavour Energy based on current estimates of yields on 10 year BBB corporate bonds prevailing over the period February to June 2014. This includes because the AER's proposed transition applies not only to the risk-free rate component of the return on debt (which is relevant to the benchmark efficient entity hedging issue), but also to the debt risk premium component of the return on debt, which is irrelevant to the benchmark efficient entity hedging issue. In circumstances where an entity acting in accordance with the AER's benchmark efficient entity would be coming into the 2014-19 period with a cost of debt comprising a trailing average in respect of the debt risk premium component, the AER's transitional approach is unreasonable and illogical, even more so in respect of entities, such as Endeavour Energy who already implement a trailing average approach.
- We consider that the RBA is an independent and robust source of data for estimating yields on Australian corporate bonds and there is a clearly agreed approach between the AER and Endeavour Energy on how to adjust the RBA's estimate to an effective maturity of 10 years, where the effective maturity of the AER's broad BBB yield estimates are greater or less than 10 years. We also consider that the evidence presented in our initial proposal demonstrated that the benchmark efficient credit rating is currently BBB, not BBB+.
- We propose an allowed return on equity of 10.15%, which has been estimated using internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity has been selected from a reasonable range that has regard to all relevant evidence including the CAPM (both the Sharpe-Lintner and Black versions), the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM) as required by 6.5.2(e)(1) of the NER. Our proposed return on equity also has regard to prevailing conditions as required by clauses 6.5.2(g) of the NER. Our proposed return on equity is significantly lower than allowed return on equity for the 2009-14 period of 11.82% and reflects lower required returns on equity currently than were required at the time of the previous determination.

Our revised rate of return has been developed to meet the requirements of the Rules, to contribute to the achievement of the NEO as set out in section 7 of the NEL, and to be consistent with the revenue and pricing principles set out in section 7A of NEL. In particular, clause 6.5.2(b) of the Rules provides that the allowed rate of return is to be determined such that it achieves the allowed rate of return objective, which is that:

> *"...the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective)."*

As set out above, our proposed rate of return has been developed to be commensurate with the efficient financing costs of a benchmark entity with a similar degree of risk as that which applies to Endeavour Energy in providing standard control services.

In setting the allowed rate of return, clause 6.5.2(e) of the Rules also require that the AER must have regard to:

> *(1) relevant estimation methods, financial models, market data and other evidence;*
>
> *(2) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and*

(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

Consistent with the Rule requirements, our proposed rate of return is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Endeavour Energy over the 2014-19 period.[249]

Our proposed rate of return has been informed by leading financial and economic experts and we have attached a number of expert reports and other evidence in support of our position, including reports from Competition Economics Group (CEG),[250] Frontier Economics,[251] SFG Consulting (SFG),[252] Professor Bruce Grundy,[253] NERA,[254] a letter from the Australian Office of Financial Management[255] and a Statement from the Group Chief Financial Officer Networks NSW regarding debt management practices including the specific circumstances of the NSW DNSPs (Ausgrid, Endeavour Energy and Essential Energy).[256] The attached CEG reports reference an extensive number of relevant documents and expert reports, many of which were provided as attachments to our initial proposal submitted on 30 May 2014. Only new or updated expert reports are attached to this revised proposal.

We note, that additional detailed analysis is being completed that will elaborate on issues raised within SFG's attached report on the cost of equity for ActewAGL and the NSW DNSPs. SFG will also be preparing more detailed analysis on the value of imputation credits that we intend to provide to the AER as soon as possible. We have also requested Professor Bruce Grundy to provide updated analysis on the evidence of bias within the SL CAPM and a response to Associate Professor Handley's report on the cost of equity. We note that the substance of the analysis to be covered in these reports are raised in our revised proposal and supporting attachments. However, given the tight timeframe within which we are required to submit a revised proposal and the breadth of issues raised in the AER's draft decision, the analysis could not be completed in time to attach with our revised proposal. We will provide these reports to the AER as soon as possible, and at the very least before the closing date for submissions on the AER's draft decision for Endeavour Energy.

The breakdown of our proposed rate of return is outlined in Table 7.1 below.

Table 7.1 – Initial and revised proposal rate of return

Parameters	2009-14 determination	Initial Proposal	AER Draft Decision	Revised Proposal
Overall WACC	**10.02%**	**8.83%**	**7.15%**	**8.85%**
Cost of equity	11.82%	10.11%	8.1%	10.15%
Cost of debt	8.82%	7.98%	6.5%	7.98%
Gearing	60%	60%	60%	60%
Gamma	50%	25%	40%	25%

[249] As required by clause 6.5.2(c) of the NER.

[250] CEG, Efficient debt financing costs, January 2015 and CEG, Estimating the cost of equity, January 2015.

[251] Frontier Economics, Cost of debt transition for NSW distribution networks, January 2015.

[252] SFG, The required return on equity: Initial review of the AER draft decisions, Note for ActewAGL, Ausgrid, Essential Energy and Endeavour Energy, January 2015.

[253] Letter from Professor Bruce Grundy to Justin De Lorenzo - 9 January 2015.

[254] NERA, Memo on Revised MRP estimates to 2013, 14 November 2014.

[255] Letter from Michael Bath of the Australian Office of Financial Management to Steve Knight regarding domestic interest rate swaps, 5 January 2015.

[256] Statement from Group Chief Financial Officer, Networks NSW, January 2015.

7 ALLOWED RATE OF RETURN

In this revised proposal we have responded to a number of the AER's constituent decisions on significant building block elements, in particular forecast operating expenditure and forecast capital expenditure. To the extent the AER, in its final decision, maintains that significant reductions to these forecast expenditure amounts is appropriate, the AER will need to consider the impact of these reductions on the appropriate rate of return allowance. In particular, such reductions are likely to significantly impact on credit ratings and parameters such as the equity beta. This includes also because any such final decision is likely to result in how stakeholders perceive the stability of the regulatory regime and the risks associated with it.

7.1. Return on debt

The AER's draft decision has agreed to the position put forward by Endeavour Energy in our initial proposal that the allowed return on debt should be estimated using a 10 year trailing average approach that will be annual updated throughout the regulatory period. However, the AER's draft decision proposes to transition Endeavour Energy to a trailing average return on debt allowance from an “on the day” estimate over 10 years.

We have serious concerns over the AER's proposed debt transition approach because it varies significantly from the cost of debt that would be incurred by a benchmark efficient entity facing similar risks as Endeavour Energy. The transition would, if implemented when rates remain at current levels, result in significant losses to Endeavour Energy relative to its efficient costs of debt finance over the period 2014-19. This is not consistent with the allowed rate of return objective, the revenue and pricing principles or the NEO, which require that a network service provider be provided with a reasonable opportunity to recover at least its efficient costs so as to promote the efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity.

The AER's draft decision did not accept our proposed approach to annually updating the cost of debt using data published by the Reserve Bank of Australia (RBA). The RBA is a highly reliable source for Australian financial market data and at present is the only provider that provides estimates with a target maturity of 10 years.

The AER's draft decision also assumed a benchmark efficient credit rating of BBB+. This is inconsistent with the market evidence presented in our initial proposal, which demonstrated that the benchmark credit rating for energy network firms is currently BBB and is expected to be BBB over the 2014-19 regulatory period.

The remainder of this section explains:

- The reasons why the staggered portfolio approach is the benchmark efficient practice for managing debt. The trailing average approach reflects the cost of debt raised on this basis and should be used to set the allowed return on debt for Endeavour Energy, without transition.
- A debt transition would only be appropriate where a DNSP is likely to incur costs to transition its debt management practices to the benchmark efficient staggered portfolio approach. This is not the case for Endeavour Energy.
- The AER's debt transition would not provide a return on debt that is commensurate with the efficient debt financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Endeavour Energy based on the currently estimated cost of broad BBB rated debt. This result is contrary to the requirements of the NER and the Revenue and Pricing Principles contained in section 7A of the NEL.
- It would not have been possible, nor would it have been efficient for Endeavour Energy to undertake a swap based strategy at the time of the previous determination. According to both the Australian Office of Financial Management (AOFM) and analysis by UBS, liquidity for these instruments was at best ‘thin’ in the Australian market following the GFC.
- In addition to this, at the time of the previous determination, the final averaging period to be applied by the AER was actually in dispute. Further the averaging period for the next regulatory determination i.e.

2014-2019 was not known, so the effective termination date for any swaps entered into in 2009 was also unknown.

- Government ownership was not the reason that Endeavour Energy did not undertake the swap based strategy, Endeavour Energy's treasury managers were well aware of the potential of interest rate swaps and determined that the staggered portfolio approach was the efficient strategy for managing Endeavour Energy's debt portfolio, which is confirmed by the analysis from UBS, Frontier and CEG.
- Endeavour Energy considers that the RBA should be chosen as the data source for estimating the allowed return on debt and based on the data provided in our initial proposal a benchmark credit rating of BBB should be assumed.

7.1.1 The trailing average approach

The trailing average approach estimates the cost of debt issued on a benchmark efficient staggered portfolio basis. The AER's guideline correctly notes that in the presence of refinancing risks, the benchmark efficient entity would have managed a staggered debt portfolio. We agree with this position and say also that in the presence of interest rate risk, a benchmark efficient strategy would also be to manage a staggered debt portfolio. We note refinancing risks are relevant to consider when setting the allowed return on debt because they have material implications for the financial sustainability of Endeavour Energy in providing network services.

Refinancing risks are realised when a business requires new debt to replace maturing debt and there is:

- a lack of liquidity in debt markets to raise new debt to do so (i.e. no willing debt investors), and/or
- the cost of new debt is so high that the business will be unable to afford it.

Realising refinancing risks can lead to insolvency, which is what occurred for a number of businesses during the Global Financial Crisis (GFC) in 2008. Endeavour Energy's determination for the 2009-14 period was taking place in the midst of the GFC and significant refinancing risks existed at that time. Refinancing risks are still present today and large capital-intensive businesses are particularly prone to them. However, we agree with the AER that refinancing risks can be effectively managed by issuing a staggered debt portfolio.

Issuing debt with staggered maturities is also an effective way to manage interest rate risks because it diversifies a business' exposure to interest rates that prevail across time. When managing a large debt portfolio such as Endeavour Energy's, it is simply not feasible, or alternatively, economic, to use derivative instruments to lock-in the rate of interest on debt over a long term period for purposes such as budget certainty or matching interest costs with expected revenues and regulatory allowances.

The effectiveness of the staggered portfolio approach in reducing risks for Endeavour Energy is outlined in the attached statement from Justin De Lorenzo, Group CFO of Networks NSW, which operates across Ausgrid, Endeavour and Essential. In his statement, Mr De Lorenzo concludes that:

> *"…it remains my firm belief that the most efficient debt management approach that reduces risks for the businesses remains the staggered portfolio average approach which is consistent with the trailing average approach applied by the NSW Businesses."*[257]

These points are evidenced by the practice of unregulated infrastructure firms and most Australian corporates. As noted by UBS, the predominant debt management approach of non-regulated infrastructure firms such as ports, airports, roads and railways is to issue debt on a staggered portfolio/trailing average basis.[258]

[257] Statement of Justin De Lorenzo, Group CFO, Networks NSW.

[258] UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p. 5.

For the reasons outlined above the benchmark efficient practice is to issue debt on a staggered debt portfolio basis. The AER agrees that this is what a benchmark efficient entity would do. The ability to recognise this benchmark efficient approach through a trailing average return on debt allowance has been made possible through the recent changes to the NER. The amendments, which provide for the return on debt being, or potentially being, different for different regulatory years in a regulatory period, allow a trailing average to be adopted to estimate the allowed return on debt, whereas in the past the Rules required the return on debt to be estimated using one short-term observation period with no ability to update the return on debt component of the allowed rate of return during the regulatory control period.

Minimising any difference of the allowed return on debt to that of a benchmark efficient entity

Clause 6.5.2(k)(1) of the NER requires that in estimating the allowed return on debt, regard must be had to the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity. As outlined in our initial proposal, this revised proposal and the supporting attachments to these documents, the benchmark efficient return on debt for a business facing a similar nature and degree of risks as Endeavour Energy, is the cost of issuing debt on a fixed rate staggered portfolio basis. The cost of issuing debt on the benchmark efficient staggered portfolio basis can be estimated using the trailing average approach. We note that the ability of the trailing average approach to achieve the objective of clause 6.5.2(k)(1) was clearly highlighted in the explanatory statement to the AER's final rate of return guideline.[259] On this basis, we consider that applying the trailing average approach should be used to estimate the allowed return on debt for Endeavour Energy over the 2014-19 period.

7.1.2 Transition to the trailing average return on debt

Justification for a debt transition

The AER's draft determination proposes that a transition should be applied to move from the "on-the-day" approach to the trailing average approach for setting the allowed return on debt.

The application of any transition to Endeavour Energy involves a misapplication of the NER. By clause 6.5.2(h), the return on debt for a regulatory year must be estimated such that it contributes to the achievement of the allowed rate of return objective. The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services.

The AER has correctly recognised that the trailing average approach is the best measure of the efficient financing costs of a benchmark efficient entity. Endeavour Energy has already adopted an approach to financing its debt consistent with the trailing average approach: that is, a staggered fixed-rate debt portfolio, without conversion of the fixed-rate debt to floating rate debt. There is therefore no reason to apply a transition to Endeavour Energy in moving to the best measure. The imposition of a transition:

(a) delays the imposition of the best approach, and prolongs the use of an inferior approach;

(b) has been imposed on the basis of hypothetical issues said to arise in the case of a hypothetical entity in a very different position from Endeavour Energy, and which are therefore irrelevant to Endeavour Energy; and

(c) would produce a result for Endeavour Energy that does not permit Endeavour Energy to recover its efficient cost of debt.

There are no relevant "impacts" on Endeavour Energy or on customers of Endeavour Energy that arise as a result of changing the methodology from the "on-the-day" approach to the trailing average approach. In fact,

[259] AER, Explanatory Statement, Final rate of return guideline, p. 109.

the only relevant “impacts” that arise for Endeavour Energy arise precisely because the AER proposes to apply the transitional arrangements to it - it is the application of these arrangements that will result in Endeavour Energy not being provided with a reasonable opportunity to recover its efficient debt financing costs over the period 2014-19.

At a fundamental level, imposing a form of transition so as to avoid issues, which would arise by the immediate application of a preferred methodology could only ever be appropriate if those issues would in fact arise in relation to the entity in question. It is inappropriate to impose a transition to the best method – i.e. a delay, or partial delay, in the application of the best method – in respect of alleged issues that do not arise in the case of the entity in question. There is nothing in the Rules that says that every entity has to have the same return on debt, or the same approach to the return on debt. Nor does clause 6.5.2(k)(4) require or permit the AER to have regard to impacts that are irrelevant to the service provider in question. Rather, on its proper construction, the reference to “impacts… on a benchmark efficient entity” in clause 6.5.2(k)(4) is a reference to impacts that are not idiosyncratic impacts on a particular service provider only, but are impacts that would **also** be incurred if the service provider was a benchmark efficient entity. It certainly does not refer to impacts that are irrelevant to the entity in question, which is how the AER appears to have interpreted the rule.

Further, the AER’s approach of seeking to establish the characteristics of a single hypothetical efficient benchmark entity, and then analyzing issues that might arise for that hypothetical entity, is inconsistent with the rationale for the amendments to the relevant Rules. In its 2012 Rule Determination, the AEMC emphasised that:

> *“efficient benchmark service providers may have different efficient debt management strategies”;*
>
> a) *“debt management practices tend to differ according to the size of the business, the asset base of the business, and the ownership structure of the business”;*
>
> b) *there was a problem with the “one-size-fits-all” approach under the existing rules, and that a one-size-fits-all approach should not be considered a default position;*
>
> c) *“the regulator could adopt more than one approach to estimating the return on debt having regard to different risk characteristics of benchmark efficient service providers”.* [260]

At the very least, the AEMC Rule Determination emphasizes that pursuant to amended clause 6.5.2, the AER may need to consider more than one type of benchmark efficient service provider. This is emphasized in the specification of the rate of return objective in clause 6.5.2(c), which states that the rate of return objective for a DNSP is to be commensurate with the efficient financing costs of a benchmark efficient entity with *a similar degree of risk as that which applies to the DNSP*. Likewise, clause 6.5.2(k)(4) refers to impacts on a benchmark efficient entity “referred to in the *allowed rate of return objective*” – that is, an entity with a similar degree of risk as that which applies to Endeavour Energy.

In the present case, it is clear that it was not rational, efficient, or economic for large service providers to enter into floating rate hedges or five-year floating to fixed rate hedges, so as to match as best they can the regulatory return under the “on-the-day” approach. Rather, such entities would generally manage debt simply by means of staggered fixed-rate facilities, being an approach that would rationally be used by all entities under the trailing average return approach. Therefore, even if it was appropriate to posit “impacts” merely by reference to a hypothetical benchmark efficient entity (which is not the case), the AER has stipulated the wrong such entity in the case of Endeavour Energy. The relevant benchmark efficient entity in the case of Endeavour Energy is a large entity that relies upon staggered fixed-rate facilities to manage its debt and its debt risk profile.

The draft decision relies upon additional reasons for the imposition of a transition. The first of these relates to the debt risk premium component of the relevant debt. The draft decision correctly recognises that even in the case of the hypothetical entity posited by the AER (i.e. a smaller privately-owned entity that has floating rate

[260] AEMC, *Rule Determination*, 29 November 2012, at pp 84, 85, 86, 90

debt, either directly or by the use of hedges, that will continue into the next regulatory period), the impact of the existing floating rate arrangements is only relevant to the risk-free rate portion of the debt, not the portion referable to the debt risk premium. In relation to the DRP component of the debt, the AER contends that benefits were obtained in the last period (due to a spike in the DRP) that need to be balanced out before the new methodology is applied, because otherwise the new methodology would perpetuate a gain. There are a number of considerable difficulties with this approach:

(a) It is not consistent with proper economic regulatory practice. Proper economic regulation of monopoly infrastructure employs a forward-looking approach to assess an appropriate amount of revenue based on the best available methodology. It is inconsistent with this approach to employ a methodology that does not properly assess the cost of debt, in the hope that the entity will obtain less than an appropriate return in order to balance up an alleged over-recovery in a previous period. Put another way, proper regulatory practice does not involve tallying up alleged over or under recovery and setting a rate of return, or any other building block, on the footing that it will balance out the ledger.

(b) It would not be consistent with the national electricity objective to select out an alleged case of over-recovery on one component in a single period without considering all other potential cases of over or under-recovery in that or any other period. This is simply impractical and inconsistent with proper regulatory practice. The alleged DRP “spike”, if it led to “over-recovery” in the last regulatory period, necessarily caused under-recovery in the previous period as DRP was “spiking” but the allowed DRP remained steady.

(c) As explained by Dr Hird in his report,[261] the calculations underpinning the allegation are incorrect and the alleged over-recovery is therefore factually incorrect. In fact, there was no over-recovery by reference to the AER’s benchmark efficient strategy under the previous Rules. Indeed, as explained by Dr Hird, looking over the 2009-14 period and taking into account Endeavour Energy’s final averaging period, there would have been an under-recovery of costs.

(d) As a general rule, the AER’s approach also requires a speculative assumption about the size of the DRP in the initial averaging period. That is unwarranted and liable to error.

Dr Hird also explains why the “NPV neutrality” reasoning advanced by the AER is incorrect. To have another roll of the dice of a method that locks in rates for 5 years on a single day does not promote NPV neutrality. A service provider may do better or worse than a “neutral” result. Further, to speak of adopting a previous methodology to promote NPV neutrality over the life of the asset makes no sense in circumstances where the RAB is constantly changing and being renewed.

These issues are dealt with in more detail in the following paragraphs.

Although not stated in the draft decision or the guideline, it appears that the AER relies on clause 6.5.2(k)(4) of the NER to impose a transition if it considers it appropriate to do so.[262] Clause 6.5.2(k(4) states that the AER must have regard to:

> *“any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.”*

One matter should be immediately noted with respect to clause 6.5.2(k)(4). It is one of four matters to which the NER direct the AER to have regard in estimating the return on debt under clause 6.5.2(h). Another particularly relevant matter referred to in clause 6.5.2(k) to which the NER direct the AER to have regard in estimating the return on debt is the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity (clause 6.5.2(k)(1)). The other factors (the interrelationship

[261] CEG, Efficient debt financing costs, January 2015.

[262] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, p 120.

between the return on equity and the return on debt, and the incentives that the return on debt may provide in relation to capital expenditure, particularly as to the timing of that expenditure) are also relevant. In estimating the return on debt it is unclear from the AER's draft decision how the AER has actively had regard to factors (1) to (3) in estimating the return on debt.

A transition may be necessary for businesses that do not currently manage their debt on a staggered portfolio basis. However, Endeavour Energy has consistently issued debt on a staggered portfolio basis and that is the current practice, as explained in the statement of Mr De Lorenzo. As outlined above, the AER has determined that this is consistent with what a benchmark efficient entity would do.

The AER's justification for the debt transition is based on advice from its consultant Associate Professor Lally. Lally's advice is that any network business that raised debt on a basis other than the 'on the day' approach, *may* have achieved a lower actual cost of debt than the allowed return on debt in their determination. Lally argues that any business that achieved a lower actual cost of debt (by any means including by using a staggered portfolio approach) was overcompensated in the past. Lally goes on to argue that Endeavour Energy should be under-compensated in the 2014-19 regulatory period to "average out" this perceived over-compensation and ensure no gain or less in net present value (NPV) terms (i.e.an NPV=0) outcome over the past two regulatory periods. The attached cost of debt reports prepared by Frontier Economics and CEG clearly demonstrate that this is the basis of the AER's transition approach as set out in the draft decision.[263]

Therefore, rather than interpreting clause 6.5.2 (k) of the NER as requiring the AER to consider any additional costs/risks created by a change in the regulatory approach, the AER is interpreting this clause to support a transition that would result in windfall losses for Endeavour Energy, simply because it issued debt using a benchmark efficient, risk mitigating, staggered portfolio approach in the past.

We note that "averaging out" perceived over-compensation in a past regulatory period is not a justification under the NER, for applying a windfall loss to Endeavour Energy in the forthcoming period. Furthermore, the NPV=0 principle needs to be applied for future periods (and in *present* not *past* value terms) to provide the correct incentives for efficient investment in the electricity network. Applying the AER's debt transition would, if applied over the 2014-19 period, result in a net present value less than zero (i.e. NPV < 0) outcome by not allowing Endeavour Energy to recover at least its efficient costs of debt finance incurred for the provision of network services. This is inconsistent with the revenue and pricing principles in section 7A of the NEL.

The AER's proposal to apply the transitional arrangements to Endeavour Energy is not supported by the NER. The NER require a return on capital for each regulatory year of the 2014-19 period to be calculated by applying a rate of return for the relevant DNSP for that regulatory year that is determined in accordance with clause 6.5.2 to the value of the RAB. The allowed rate of return objective, by reference to which the return on debt is required to be estimated, is that the rate of return for a DNSP is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the DNSP. What is being determined pursuant to these provisions is a return on debt (and ultimately an allowed rate of return) that is commensurate with efficient financing costs **in the relevant regulatory period**. In this particular case, the efficient financing costs in the transitional regulatory control period (2014-15) and the efficient financing costs in the subsequent regulatory control period (2015-19).

To the extent the AER considers the "on-the-day" approach resulted in a cost of debt in the 2009-14 regulatory control period that was "too high" and resulted in "over-compensation", this is irrelevant to the efficient financing costs of a benchmark efficient entity in the 2014-19 period. To the extent there was any "over-compensation" in respect of the 2009-14 regulatory control period, that has no impact on the efficient financing costs of a benchmark efficient entity in the 2014-19 period. With respect to at least the debt risk premium component of return on debt, the efficient financing costs, by reference to the AER's benchmark efficient entity, are an average of the debt risk premiums that prevailed on average over the past 10 years.

[263] Frontier Economics, *Cost of debt transition for the NSW DNSPs*, January 2015. CEG, Debt financing costs, January 2015.

7 ALLOWED RATE OF RETURN

Windfall losses to Endeavour Energy just from maintaining its benchmark efficient approach

Endeavour Energy has consistently issued debt on a staggered portfolio basis and the AER has determined that this is consistent with what a benchmark efficient entity would do in the presence of refinancing risks. There are no relevant “impacts” on Endeavour Energy that arise as a result of changing the methodology from the “on-the-day” approach to the trailing average approach. In fact, the only relevant “impacts” that arise for Endeavour Energy arise precisely because the AER proposes to apply the transitional arrangements to it - it is the application of these arrangements that will result in Endeavour Energy not being provided with a reasonable opportunity to recover its efficient debt financing costs over the period 2014-19.

The degree of under-compensation is outlined in the tables below. In these circumstances Endeavour Energy can, and, consistently with the Law and the Rules, must be, immediately transitioned to the trailing average cost of debt approach.

Table 7.2: Benchmark efficient return on debt vs AER’s transitional return on debt allowance

	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Trailing average using an average of Bloomberg and RBA data	7.92%	7.81%	7.62%	7.42%	7.14%	**7.58%**
AER draft decision return on debt	6.51%	6.36%	6.19%	6.03%	5.90%	**6.20%**
Difference	-1.42%	-1.45%	-1.44%	-1.39%	-1.24%	-1.39%

Note: This assumes the AER’s starting point for the debt transition would be rates prevailing from 28 February 2014 to 30 June 2014. We do not propose to use an average of the Bloomberg and RBA forecasts to estimate the allowed rate of return. However, we average the RBA and Bloomberg historical forecasts to isolate the impact of the debt transition in the table above.

Table 7.3: Windfall loss on Endeavour Energy’s notional debt portfolio due to AER debt transition ($m, Nominal)

($m, Nominal)	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Benchmark efficient debt portfolio	$3,349	$3,572	$3,746	$3,885	$4,020	**$18,572**
Under-compensation due to AER debt transition	$47	$52	$54	$54	$51	**$259**

Note: The notional debt portfolios are estimated as at the beginning of each financial year based on forecast capex and WACC within this revised regulatory proposal. We note that the impact of averaging the RBA and Bloomberg data sources is not covered in the above under-compensation. This under-compensation is based on the forecast rates outlined in the preceding table. We note that UBS has estimated a similar figure, but UBS uses the aggregate difference between our forecast return on debt and the AER’s draft decision to calculate under-compensation on the combined starting RAB values for the NSW DNSPs.

The costs of unwinding debt to match arrangements implied by AER's transition approach

With regard to the need for transitional arrangements, the AEMC's consultant, SFG, outlined that, if there was a change in the approach to setting the allowed return on debt as a result of changes to the NER, some service providers may need to unwind existing financial arrangements. The AEMC's consultant stated that it was for this reason that the AEMC should consider transitional arrangements for the cost of debt.[264] Endeavour Energy would not need to unwind any existing financial arrangements to adapt to an allowed return on debt calculated using the trailing average approach.

However, to adjust its actual financing practices to match those implied by the AER's debt transition, Endeavour Energy would incur material costs to re-issue all of its existing debt over a short averaging period and then slowly refinance approximately 10% of its debt portfolio each year for the next 10 years. To unwind existing debt financing, Endeavour Energy would need to compensate its debt-holders for the difference between the committed interest costs on fixed rate debt and prevailing interest rates for 10 year debt. The estimated "mark-to-market" cost of refinancing Endeavour Energy's existing debt portfolio as estimated at November 2014, was approximately $349 million. When this mark-to-market cost is combined with prevailing cost of debt for 10 year BBB debt, the total cost of matching Endeavour Energy's debt financing practices with those implied by the AER's debt transition would exceed even the windfall loss being faced by Endeavour Energy if it maintained its benchmark efficient debt strategy and the AER used the transition approach to setting Endeavour Energy's allowed return on debt for the 2014-19 period (as outlined above). These costs are neither efficient nor rational. However, without them, the "on-the-day" approach incorporated into the AER"s transition will not be an appropriate proxy for the return on debt for Endeavour Energy.

Efficient debt management under the previous framework

Under the previous Rules, the AER set the cost of debt using one averaging period (at the time 10-40 business days). One incentive that was created by such an approach was for businesses to refinance all debt over the 10-40 day averaging period set by the AER because this would minimise the risk of incurring an actual cost of debt that was higher than that set by the regulator to the extent that they sought to manage their interest rate risk. However, issuing debt in this manner would have resulted in significant refinancing risks around the time of a regulatory determination. Importantly, the previous Rules were written prior to the GFC, and as such were unlikely to have fully contemplated a benchmark efficient network service provider's exposure to refinancing risks. The previous Rules, which provided for the return on debt to be estimated over one short time period and which did not provide for the return on debt to be able to be updated during a regulatory control period did not provide for a trailing average approach to be adopted.

The AER has devoted much effort to determining how it considers a "benchmark efficient entity" would have structured its debt portfolio under the previous "on-the day" regulatory approach. Even though the AER never defined the benchmark efficient strategy for issuing debt when implementing the previous Rules, the AER has now determined that there is only one approach that a benchmark efficient entity could have adopted. The AER's draft decision concluded that the efficient debt management practice under the previous Rules would have been to issue floating rate debt on a staggered basis, i.e. with maturities throughout the regulatory period and then use interest rate swaps to fix the base rate of interest to that prevailing over the averaging period applied by the AER for five years. This approach would have allowed a business to roughly match the base rate of interest to that applied by the AER.[265]

The AER's approach fails to:

a) acknowledge that there may have been a number of different ways in which a prudent and efficient business could have sought to manage its debt costs under the on-the-day approach,

[264] SFG, Rule change proposals relating to the debt component of the regulated rate of return, Report for the AEMC, 21 August 2012, pp. 52-58.

[265] This approach would not enable a perfect hedge of the base rate because interest rate swaps are set on the basis of the bank bill swap rate, which mostly (but not always) has traded at a slight premium to the risk free rate proxy used by the AER – 10 year Commonwealth Government Securities.

including in light of the circumstances that prevail at the commencement of different regulatory periods; and

b) have regard to the fundamental differences that exist between the various regulated entities and how these differences would impact on the approach taken to managing debt costs.

It is clear under the Rules that there are differences between benchmark efficient entities. This is specifically recognised in the allowed rate of return objective, which refers to “a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider”.

Moreover, and as noted above, the AER’s proposed transition approach for setting the allowed return on debt would not even match the costs of transition for a business that followed its claimed benchmark efficient approach under the previous Rules. The “on the day” approach for setting the allowed return on debt, from which the AER proposes to begin its transition, compensates businesses for the current cost of debt finance. However, the cost of debt incurred by a business that used the AER’s claimed benchmark efficient approach would be a combination of the current base rate of interest (conventionally measured using the 10 year bank bill swap rate) and a trailing average DRP measured as the 10 year average DRP. This is a separate issue from whether hedging of the risk-free rate was undertaken.

Certain privately owned businesses did undertake the interest rate swap based approach referred to by the AER. However, as outlined in Frontier’s report on the cost of debt transition, this was only in response to the regulatory approach to setting the allowed return on debt. The swap-based approach is not the observed practice of unregulated infrastructure firms. We note that it was actually possible for these businesses to hedge their base rate of interest over a 40-day averaging period using interest rate swaps because of the small aggregate size of their debt portfolios compared to larger businesses such as Endeavour Energy. These businesses’ debt portfolios were, and still are, much smaller than Endeavour Energy’s.

We note that for businesses that undertook the swap based strategy a debt transition based on the costs of transitioning from this approach to the trailing average approach may be appropriate. In contrast to the businesses that undertook the swap based strategy, all larger energy network firms issued debt using a fixed rate staggered portfolio approach under the previous Rules.

Endeavour Energy’s ability to engage in interest rate swap strategy and costs of doing so

Endeavour Energy, along with the other NSW DNSPs requested that UBS AG Australia (UBS) analyse the cost and ability of Endeavour Energy to issue debt using the swap based strategy, which the AER has referred to as the single efficient response to the previous approach for setting the allowed return on debt.

The UBS analysis demonstrates that the swap based approach was not available to the NSW DNSPs including Endeavour Energy at the time of the 2009-14 regulatory determination. Given the size of notional debt financing requirements across businesses that were facing regulatory determinations at the same time, it would have been impossible to hedge the required debt financing in the Australian market using interest rate swaps over the maximum 40 day period allowed by the AER under the previous Rules (let alone the 15 business day averaging period actually applied by the AER) without causing market dislocation or exhausting available liquidity.

We also note that around the time of the AER’s previous determination the AOFM was trading in swap markets at that time in order to unwind its $20.65 billion domestic interest rate swap portfolio. This is a similar magnitude of the same type of swap contracts (pay fixed receive floating) that the AER believes that Endeavour Energy and other NSW electricity businesses should have efficiently completed over 40 days. The AOFM managed to spread $15bn in swaps over more than six months from November 2008 to May 2009. Moreover, the AOFM transactions were spread over maturities of 0.18 to 8.25 years. The transactions that the AER believes that Endeavour Energy and other NSW electricity businesses should have completed within 40 days would all have been at the 5 year tenor – exacerbating the liquidity constraints faced by the AOFM. This is outlined in the attached letter from Mr. Michael Bath of the Australian Office of Financial Management (AOFM) to the CEO of TCorp.

The AOFM's letter summarises that:

1. Despite the wide spread of maturities, market liquidity could best be described as 'thin' during the onset and immediate aftermath of the financial crisis; and
2. Executing the swaps in a significantly shorter period would, in our view, have been problematic.

This evidence, illustrates that if Endeavour Energy had tried to undertake the swap based strategy it would have had to compete with the AOFM in an already thin trading environment for a specific maturity (i.e. 5 years to cover the regulatory period). This provides weight to the UBS analysis, which concluded that it would not have been possible for Endeavour Energy to undertake the swap based strategy over a 40 business day averaging period without causing market dislocation or exhausting available liquidity.

UBS analysis demonstrates that even if the NSW DNSPs were able to issue debt over an averaging period that was longer than the AER's maximum allowed averaging period of 40 business days (noting that the AER's allowed averaging period was actually only 15 days), it would be a significantly longer period than 40 days and would have provided a very poor hedge to base interest rates prevailing during the regulatory averaging period. Such an approach would also have exposed Endeavour Energy to much greater interest rate risks than issuing fixed rate debt on a staggered portfolio basis as Endeavour Energy did. The staggered portfolio approach enabled Endeavour Energy to achieve the following efficient outcomes over the 2009-14 period:

- Diversified interest rate exposure across time (i.e. hedged interest rate risks)
- Managed refinancing risks on Endeavour Energy's significant debt portfolio

Final averaging period was unknown

In addition to the fundamental inefficiency of a swap based approach for Endeavour Energy at the time of the previous determination, there was significant uncertainty about the actual averaging period that would apply to Endeavour Energy in the final determination. Endeavour Energy was in dispute with the AER over the averaging period that should be applied in the determination right up to the AER's final decision. There were three potential averaging periods:

- 15 business days starting 29 July 2008. This was the period originally proposed by Endeavour Energy and rejected by the AER as being too removed from the start of the regulatory period;
- 15 business days, 2 March 2009 to 20 March 2009. This was the averaging period applied by the AER in its final decision – which was subsequently appealed by Endeavour (Integral Energy at that time);
- 15 business days, 18 August 2008 to 5 September 2008. This was the averaging period contained in the revised proposals of the NSW DNSPs and ultimately determined by the Australian Competition Tribunal as the period that should be used by the AER to set revenues.[266]

Any hedging that was actually carried out in or around the first two averaging periods would not have hedged Endeavour Energy's actual debt costs to the actual revenue allowance for the cost of debt, which was based on the third period. However, by the time the actual averaging period was known with certainty (i.e. after the appeal to the Australian Competition Tribunal was heard and decided in November 2009) it was in the past and impossible to go back in time and issue the relevant swaps. Moreover, this averaging period was first proposed by Endeavour Energy after the period had passed and was chosen as a form of compromise between its originally proposed averaging period and the AER's proposed averaging period. This topic is dealt with in more detail in the attached CEG report on the efficient cost of debt.[267]

Therefore, in the circumstances of Endeavour Energy where the AER refused to accept Endeavour Energy's averaging period – a position that was only overturned on appeal – it was simply impossible to enter into the swap strategy that the AER regards as "efficient" – at least not without taking on the risk that the period in

[266] See Application by EnergyAustralia and Others (No 2) [2009] ACompT 8, 69(k).

[267] CEG, Efficient Debt Financing Costs, January 2015.

which the swaps were issued would not end up being the period used to measure the 'on the day' cost of debt. In these circumstances, it is incorrect to assert that a swap strategy is one that would be employed by a benchmark efficient entity.

Government ownership and effect on Endeavour Energy's debt management approach

The AER's consultant Associate Professor Lally, has suggested that government owned businesses did not use interest rate swaps to try to match actual debt costs to those set by the AER because they:

> *"are not subject to normal market signals and incentives, because they face low bankruptcy and refinancing risk, and possibly also because they borrow via another government entity (such as the QTC or the NSW Treasury Corp) and are thereby partially shielded from market signals."*[268]

This statement is incorrect. All of the NSW DNSPs (and indeed the Qld Distribution businesses) are subject to competitive neutrality regulations that ensure they face the same market signals and incentives as privately owned businesses on their cost of debt. As noted by the AEMC in its 2012 rule determination:

> *"The difference between the State's borrowing costs and the costs faced by the state-owned service providers, commonly referred to as debt guarantee fees, represents consideration due to state taxpayers for accepting the business' credit risk…From the service providers' perspective, this mechanism ensures that they face borrowing costs that reflect the nature of their businesses, not the taxation powers of their government lenders."*[269]

The NSW DNSPs issue debt through the NSW Treasury Corporation (TCorp). However, all of the NSW DNSPs are required to pay a Government Guarantee Fee (GGF) in addition to the cost of debt incurred by TCorp, which issues debt on their behalf. This means that the total cost of debt incurred by the business is equal to that which would be faced by a stand-alone corporation without government support. An independent ratings agency such as Moody's or S&P provides a stand-alone credit profile for each NSW DNSP and the GGF is applied to ensure that each NSW DNSPs actual cost of debt is equivalent to the cost of debt for a privately owned firm with that stand alone credit rating. The GGF is in effect the debt risk premium the NSW DNSPs would incur if they raised debt in a global debt market in the way that private firms do.

The GGF scheme is designed in part to ensure that state owned corporations were operating at least as efficiently as privately owned businesses. The GGF also ensures that the NSW government and NSW citizens are not left uncompensated for the additional risk incurred by issuing debt on behalf of the NSW DNSPs. Indeed, the refinancing risks for the NSW DNSPs were real in the past and remain real at present. For the NSW government to intervene in the event of a default by Endeavour Energy would be an extraordinary event and could potentially affect the credit rating of the state government. For this reason, mis-managing its debt portfolio is not a trivial matter for Endeavour Energy. NSW DNSPs are strongly incentivised to produce equity returns above those implied by the regulator to their shareholders in the form of dividends and capital growth of the equity value of the firms. This is evidenced annually via written commitments made by the board of the NSW DNSPs and the shareholders. The board and management are held to account to achieve the proposed returns. These returns are required net of the payment of the GGF. In this way the incentives experienced by NSW DNSPs is no different to those experienced by private firms.

In addition to facing a stand-alone cost of debt, each NSW DNSP is responsible for nominating the debt instruments and tenors that are issued to raise its required debt funding. This was the case in the past and continues to be the case presently. This demonstrates that the NSW DNSPs are very much exposed to "normal" market signals and would very much be exposed to the normal market signals outlined above.

Associate Professor Lally also suggested that the lack of hedging using swap transactions may have been because the NSW DNSPs were historically less aware of the full potential of swap markets. This statement is

[268] Lally, Transitional Arrangements for the Cost of Debt, November 2014, p. 28.

[269] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012: Rule Determination*, 29 November 2012, p 87.

also untrue, which can be seen from the attached confidential statement from Mr Justin De Lorenzo, Group CFO of Networks NSW. Endeavour Energy was well aware of the potential to engage is swap transactions, which would have allowed them to partially hedge their actual debt costs in the manner described by the AER. However, at the time the efficient debt management strategy chosen by Endeavour Energy was to diversify interest rate risks on its significant debt portfolio by issuing long-term debt on a staggered portfolio basis. The debt management policies past and present of Endeavour Energy, which have been provided to the AER following information requests, include a range of permitted instruments including interest rate swaps.

Transition will expose Endeavour Energy to greater risks compared to other businesses

The AER's debt transition may operate to protect certain businesses, but would, if implemented, be detrimental to others. For example, businesses that have large tranches of fixed rate debt maturing at the time of their next determination will be somewhat protected by the AER's transitional approach. For these businesses it would be impossible to immediately transition to a staggered portfolio of 10 year fixed rate debt with an equal spread of maturities due to existing financial instruments that will need to be unwound. These businesses are subject to significant interest rate risks (e.g. the potential for rates to increase rapidly and unexpectedly).

The AER's transition would set the allowed return on debt equal to the observed cost of debt around the time of its final determination for these businesses, with a lengthy transition to the trailing average. Therefore businesses that issued large tranches of debt maturing at the start of their next determination would be protected from changes in interest rates at the time of their final determinations.

Smaller businesses that followed the swap based strategy would have large volumes of swap contracts expiring at the time of their next determination leaving their base rate of interest floating at that time. These businesses would be able to convert their floating rate exposure into 10 different tranches of 1, 2, 3, to 10 year fixed swap rates so that they lock in the fixed swap rates that prevail in the AER's initial averaging period and have 10% of these expire each year. Base rates of interest could then be hedged at prevailing 10 year swap rates each year, thereby matching the AER's debt transition allowance, which adds a 10% weight to new cost of debt estimates each year.

We note that while these businesses would likely be more protected than the NSW businesses under the AER's debt transition, they would still face uncompensated costs. This is because they would only be able to issue swaps on the base rate of interest they face, the DRP component of their debt would still be a staggered portfolio/trailing average cost. In addition to this, they would incur hedging transactions costs for implementing a swap based strategy. In the past these costs would have been manageable given relatively small debt portfolios and greater swap market liquidity. However due to tighter capital market regulations implemented since the GFC and the European Sovereign Debt Crisis,[270] entering into large volumes of swap transactions may be more difficult in future determinations.

Unlike other businesses, the NSW DNSPs including Endeavour Energy already issue debt efficiently on a staggered portfolio basis and will not have a base rate of interest that is floating at the time of the next regulatory period. In contrast to the businesses who have previously committed to a swap based strategy, the transition approach set out in the AER's draft determination exposes Endeavour Energy to interest rate mis-match risk and interest rate volatility. As outlined above, based on rates in February to June 2014, would result in Endeavour Energy incurring windfall losses for having undertaken the benchmark efficient staggered portfolio approach.

[270] UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p. 13.

7.1.3 Cost of using interest rate swaps compared to the transitional return on debt allowance

The draft decision states that the benchmark efficient practice under the previous Rules would have been to issue a staggered debt portfolio of floating rate debt and then fix the base rate to the regulatory allowance. However, the AER's debt transition does not provide compensation for the costs of hedging in the manner that the AER assumes. The AER's debt transition provides compensation based on the cost of issuing the majority of the business' debt portfolio at the prevailing 10 year rate for the total cost debt.
However, even if a firm used swaps in the way envisaged by the AER, it would still be paying a trailing average debt risk premium (incorporating higher DRP costs on debt issued in the past). More importantly, for larger businesses such as Endeavour Energy there are significant hedging transactions costs for entering into swap transactions across their entire debt portfolios. The AER's draft states that these costs are insignificant, but the attached analysis prepared by UBS demonstrates that these costs are actually quite significant.

UBS has estimated that due to the size of our debt portfolio Endeavour Energy, which would need to be re-issued at the same time as the debt portfolios of the other NSW DNSPs, we would need to issue debt offshore. UBS estimated that the costs of doing so, even for a firm with a credit rating of BBB+, would be in the order of $521 million across the NSW DNSPs (approx. $279 million for Ausgrid, $109 million for Endeavour and $133 million for Essential), even before costs of additional liquidity premium and currency related volatility.[271]

UBS has indicated that the costs would be even greater at a sub-investment grade credit rating. However, the mark-to-market costs of unwinding existing debt would also need to be factored into these costs. The combined mark-to-market costs for the NSW DNSPs as estimated at November 2014 was approximately $1.92 billion (approx. $1.02 billion for Ausgrid, $349 million for Endeavour and $551 million for Essential). Therefore, even if an investment grade credit rating was assumed, the transition cost for the NSW DNSPs to move to the debt management strategy implied by the AER's proposed approach would be in excess of $2.4 billion (approx. $1.3 billion for Ausgrid, $458 million for Endeavour and $684 million for Essential) compared to no cost for an immediate transition to the trailing average approach.

Incentives for timing of efficient capital expenditure

Clause 6.5.2(k)(3) of the Rules requires that in estimating the allowed return on debt, regard must be had to incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure. As outlined above, the allowed return on debt allowance under the debt transition approach would significantly undercompensate Endeavour Energy relative to its efficient costs of debt finance. This would also place significant pressure on Endeavour Energy's financial sustainability over the 2014-19 period both separately and in combination with reductions applied in the AER's draft determination to other components of the building blocks revenue allowance.

The under-compensation in relation to the allowed return on debt, provides incentives to defer capital expenditure in order to maintain financial sustainability and/or provide required returns to equity holders. Therefore, the AER's debt transition approach to setting the allowed return on debt provides incentives to defer prudent and efficient capital expenditure. By contrast, the trailing average approach would compensate Endeavour Energy for its efficient cost of debt.

Choice of data provider

The AER's draft decision adopted an average of Bloomberg's Valuation (BVAL) curve and data on corporate bond yield from the Reserve Bank of Australia (RBA) to estimate the allowed return on debt. In this revised proposal, we maintain our initial position that where available the RBA data source should be used to estimate the trailing average cost of debt. As outlined in our initial proposal, we consider the RBA to be a highly reliable independent data service provider for estimates of yields on 10 year BBB rated Australian corporate bonds.

[271] UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p. 12.

Moreover, RBA data extends back to January 2005, which enables the use of a consistently calculated data series to estimate the trailing average cost of debt as far back as January 2005.

Benchmark efficient credit rating

In this revised proposal, we maintain our initial proposal that the benchmark efficient credit rating for energy network firms is BBB. As demonstrated in the market evidence presented in our initial proposal, the benchmark credit rating for energy network firms is currently BBB and is expected to be BBB over the 2014-19 regulatory period.

7.1.4 Debt raising costs

In this revised proposal we maintain our revised proposal on the required efficient costs of raising debt finance of 9.9bppa. This is based on the detailed analysis of debt raising costs that was completed by Incenta and attached with our initial proposal. We note that the AER has not considered the full range of efficient debt raising costs that are faced by the benchmark efficient entity. These include more than the transactions costs outlined by Incenta. They also include liquidity commitment fees and the costs of 3 months ahead financing. However, we have maintained a conservative approach to minimize the impacts of our costs on our customers and only incorporated a minimal 9.9bbpa figure for debt raising costs.

7.2. Return on equity

As required by clause 6.5.2(e)(1) of the NER, we have had regard to the range of relevant estimation methods, models, financial market data and other evidence to develop our proposed return on equity. Based on this analysis we determined a reasonable range for the benchmark efficient cost of equity for a benchmark efficient network business. We adopted a point within the reasonable range using the SL CAPM framework.

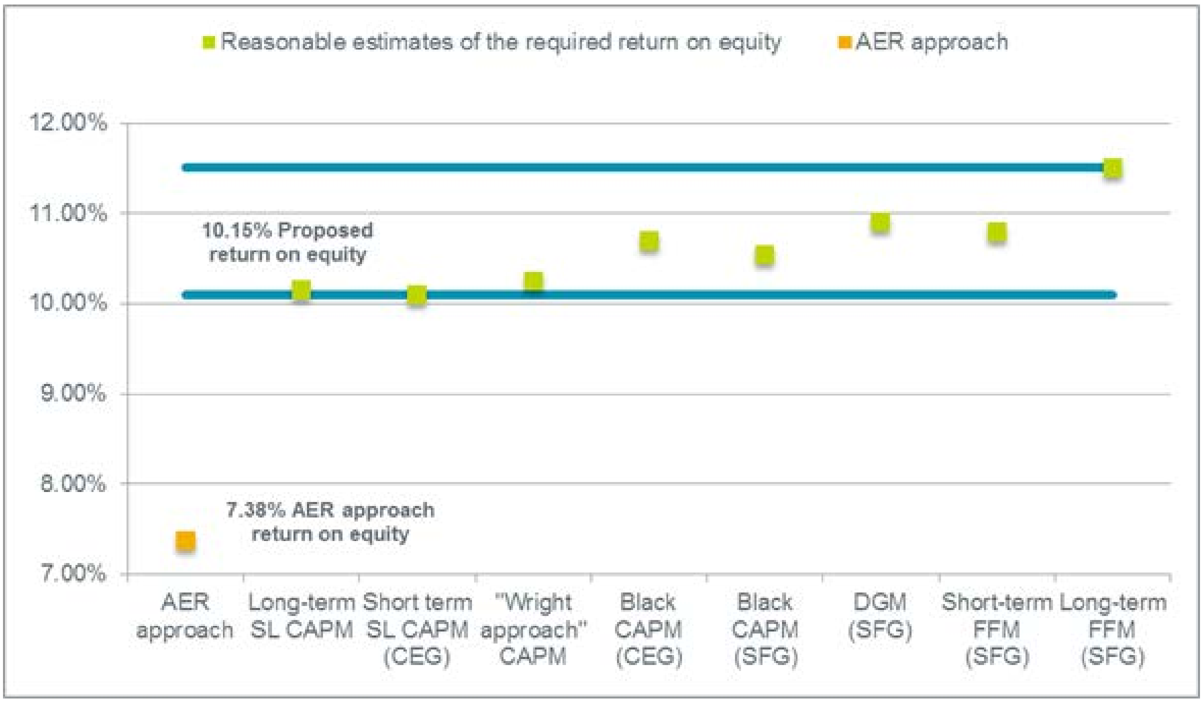
Our proposed point estimate for the return on equity is 10.15% and has been updated since our initial proposal to reflect the most recent estimates of the historical average MRP (6.56%) and the historical average real risk free rate combined with the latest forecast of inflation (4.77%). Our proposed estimate continues to uses internally consistent estimates of parameters within the capital asset pricing model (CAPM). We have reviewed the AER’s draft decision and consider that an equity beta estimate of 0.82 remains reasonable when estimating the allowed return on equity using the SL CAPM.

We note that although we have used a point estimate using the SL CAPM as a base model, our estimate has been chosen having regard to the reasonable range for the benchmark efficient cost of equity. At the time of our initial proposal, this range was estimated to be 10.1 – 11.5%. Incorporating updated data, the reasonable range for the benchmark for the purposes of this revised proposal is estimated to remain 10.1% – 11.5%.

The top end of this range is based on the benchmark efficient cost of equity under long term average market conditions as estimated by SFG using the Fama French 3 Factor Model (FFM). The bottom end of the range is now based on CEG’s estimate of the required return on equity using the SL CAPM populated with internally consistent estimates of the risk free rate and MRP over the period 28 February to 30 June 2014 and an equity beta of 0.82. Our proposed return on equity is at the lower end of the reasonable range that takes into account prevailing market conditions[272] and evidence from relevant financial models including the CAPM, the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM) as demonstrated in the graph below.[273]

[272] As required by clause 6.5.2(g) of the NER.
[273] As required by clause 6.5.2(e)(1) of the NER.

Figure 7a: Reasonable range for the allowed return on equity



In its draft decision, the AER reviewed much of the extensive information provided. However, the AER's draft decision did not have regard to all relevant evidence when estimating the benchmark efficient return on equity. In its final determination, we consider that the AER should have regard to the following evidence:

- Fama-French model based estimates of the cost of equity for the benchmark firm;
- Empirical evidence of the low beta bias of the SL CAPM;
- Black CAPM based estimates of the cost of equity for the benchmark firm (using zero beta premium estimates from SFG); and
- DGM based estimates of the cost of equity for the benchmark firm

All of these sources of evidence contain relevant information as to what the true cost of equity for a benchmark efficient energy network firm is likely to be and therefore represents relevant information within the meaning of clause 6.5.2(e)(1) of the NER. In the following sections we set out our response to the AER's draft decision, including our updated estimate of the required return on equity estimated using the latest avail different relevant financial models.

7.2.1 Sharpe-Lintner CAPM

We have updated our estimates of the return on equity using the Sharpe-Lintner CAPM (SL CAPM). Using long-term data we estimate a required return on equity of 10.15%. This estimate is also consistent with prevailing estimates of the return on equity using short term data, which produces a required return on equity of:

- 10.1% using market data over the same averaging period as the AER proposed to use for its starting point estimate of the return on debt (i.e. 28 February to 30 June 2014)
- 9.8% using market data over the 20 business days to 19 December 2014.

7 ALLOWED RATE OF RETURN

As regards the relevant averaging periods for the various return on capital parameters, the AER's draft decision adopted an averaging period for the return on debt over the 2014-19 period of 28 February to 30 June 2014 for the first observation in their transitional return on debt allowance. As outlined above, we propose that the AER immediately applies a trailing average estimate of the return on debt (which implies a 10 year historic average estimate). However, at the start of 2014, the AER required Endeavour Energy to nominate averaging periods for each year within its debt transition approach that were fully prospective. Within these constraints Endeavour Energy nominated the longest possible period available to us at that time, which was the 28 February to 30 June 2014.

We do not consider that nominating an "averaging period" is required for the measurement of the risk free rate within the SL CAPM, this was a requirement of the previous Rules. The current NER require the best estimate of the benchmark efficient cost of equity. As it is the position of Endeavour Energy that the point-estimate for the cost of equity is measured in an internally consistent manner that uses long term data (1883 - 2013) for the risk-free rate and the MRP, there is no need to specify a short-term averaging period to determine the point estimate for the cost of equity.

However, to the extent the AER maintains its position that it is necessary to specify a short-term averaging period for the measurement of the return on equity parameters (a position with which Endeavour Energy disagrees), Endeavour Energy submits that the period the AER should use is the period that has been agreed to measure the parameters for the return on debt for the 2014 year, being 28 February - 30 June 2014, and that this period be used to estimate the required return on the market as well as the risk-free rate. This period is prior to the commencement of the relevant investment period (being 2014-19) and, to the extent the AER's methodology for estimating the return on equity is to be adopted, would appear to be more appropriate than other alternatives. In particular, it is problematic to take an averaging period that significantly postdates the commencement of the investment period, as this will result in a figure which is demonstrably not the prevailing or appropriate figure for the 2014-2019 period.

In the sections below we discuss SL CAPM based estimates of the required return on equity.

Internal consistency of market risk premium and risk free rate estimates

Clause 6.5.2(e)(3) of the Rules require that in determining the allowed rate of return, regard must be had to any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt. The AER's draft decision inconsistently applied parameters within the Sharpe-Lintner CAPM (SL CAPM).

As outlined in our initial proposal, the cost of equity is defined by the SL CAPM in the following way:

Cost of equity = Risk free rate + β (Expected return on the market – Risk free rate)

The AER's draft decision condenses the (Expected return on the market – Risk free rate) into the Market Risk Premium (MRP), which is often the practice. The AER's draft decision then places the most reliance on historical estimates of the MRP, but combines this with a short-term estimate of the risk free rate observed over a different period.

The historical studies relied on by the AER to estimate the MRP apply the following steps:

1. Estimate total yearly returns on Australian stocks (dividends plus capital gains). This is equivalent to estimating the return on the market.
2. Subtract the estimated yield on 10 year Commonwealth bonds for each year.
3. Average the estimates of this difference over historical time periods.

It is clear from steps 1-3 above that the historical studies of the MRP use historical risk free rate estimates. For internal consistency when applying the SL CAPM, the risk free rate used in the first part of the SL CAPM should be estimated on the same basis as the risk free rate used in estimating the historical MRP – as a historic average over the same time period.

In support of the AER's draft decision to apply inconsistent estimates of the risk free rate and the MRP, the AER's consultant Associate Professor Lally states that, unlike the risk free rate the MRP is unobservable. Lally, then concludes that if the long term average of excess returns is a good estimate of the MRP, then the AER's approach is justified.[274] We note that within the CAPM, it is actually the expected return on the market, which is unobservable and as a result the MRP is also unobservable. However, data on the risk free rate proxy (10 year Commonwealth Government Bonds) is much more readily available from published sources and can be applied consistently in the two parts of the SL CAPM equation where it appears. We note that the unobservable nature of the expected return on the market is not a justification for using inconsistent estimates of the risk free rate and the MRP.

Prevailing market conditions

The draft decision stated that our proposed 4.8% long-term estimate of the risk free rate of (1883-2011) was not reflective of prevailing conditions in the market for funds because the current 10 year risk free rate estimate is around 3%.275 Clause 6.5.2 (g) the Rules require an estimate of the benchmark efficient return on equity that has regard to prevailing market conditions, not simply a risk free rate that has regard to the prevailing conditions in the market for funds. In fact, the Rules do not require an estimate of the risk free rate at all.

Parameters used within financial models to estimate cost of equity move over time, for example during financial crises it is likely that:

- The estimated risk free rate will become depressed below historic levels due to a "flight to safety" where funds are transferred away from risky investments into secure assets such as government bonds; and
- That the market risk premium will become elevated above historic levels.

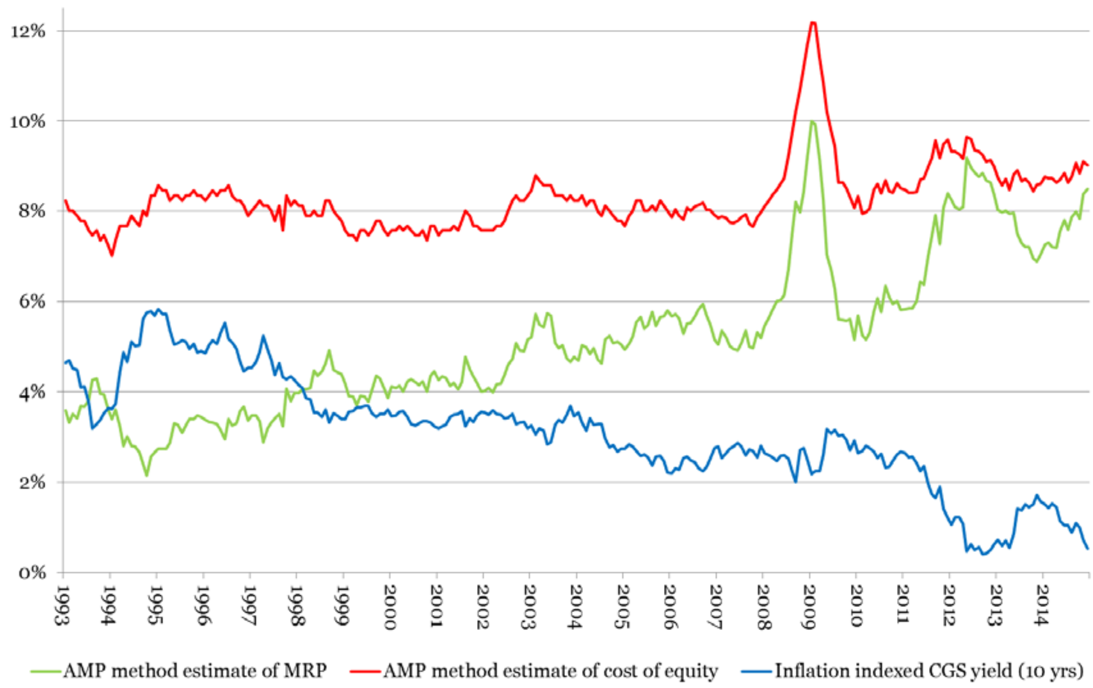
We do not submit that there is an exactly inverse relationship between the risk free rate and market risk premium parameters over time because the required return on equity may well change over time. However, if we only take the prevailing estimate for one parameter, then the resulting return on equity is unlikely to be commensurate with prevailing conditions in the market for funds. For example, if we only took the prevailing risk free rate and kept the long term MRP during a financial crisis, the return on equity would likely to be too low and if we only took the prevailing MRP during a financial crisis but a long term average for the risk free rate, the return on equity would be likely to be too high.

As demonstrated in the graph below, estimates of the risk free rate and the MRP vary over time. At times the two parameters move in opposite directions, resulting in a cost of equity for the market that moves over time but that moves less than either individual parameter and provides a more stable cost of equity estimate over time. The graph also illustrates that the cost of equity may actually move in a different direction to the risk free rate or the market risk premium at any point in time. This demonstrates the importance of estimating inter-related parameters, such as the risk free rate and the MRP, consistently. Doing so is required to ensure that the estimated overall return on equity is reflective of prevailing market conditions.

[274] Lally, Review of the AER's methodology for the risk free rate and MRP, March 2013, pp. 26-27.

[275] AER, Draft Decision, November 2013, attachment 3, p. 78

Figure 7b: Movements in the real risk free rate, market risk premium and the real cost of equity over time



Source: CEG, WACC estimates, A report for NSW DNSPs, May 2014, p. 60, as updated by CEG.

We recognise that the AER has raised concerns about whether our proposed return on equity is commensurate with the prevailing conditions in the market for funds. To address this concern we have undertaken additional analysis in this revised proposal.

First, we have updated the historical estimates of the risk free rate and the MRP to incorporate the most recent available data. The internally consistent long term estimates are:

- Risk free rate estimate of 4.77% (1883-2013)
- Expected return on the market of 11.33% (1883-2013)
- MRP estimate of 6.56% (1883-2013)

Combined with an equity beta of 0.82 this provides an estimated cost of equity of 10.15%.

Second, we have updated our estimate of the cost of equity using internally consistent short-term estimates of the risk free rate and the market risk premium. The internally consistent short-term estimates are:

- Risk free rate estimate of 3.94% (using rates observed over the AER's initial debt averaging period, 28 February to 30 June 2014)
- MRP estimate of 7.48% (using rates observed over the AER's initial debt averaging period, 28 February to 30 June 2014)

Combined with an equity beta of 0.82 this provides an estimated cost of equity of 10.1%.

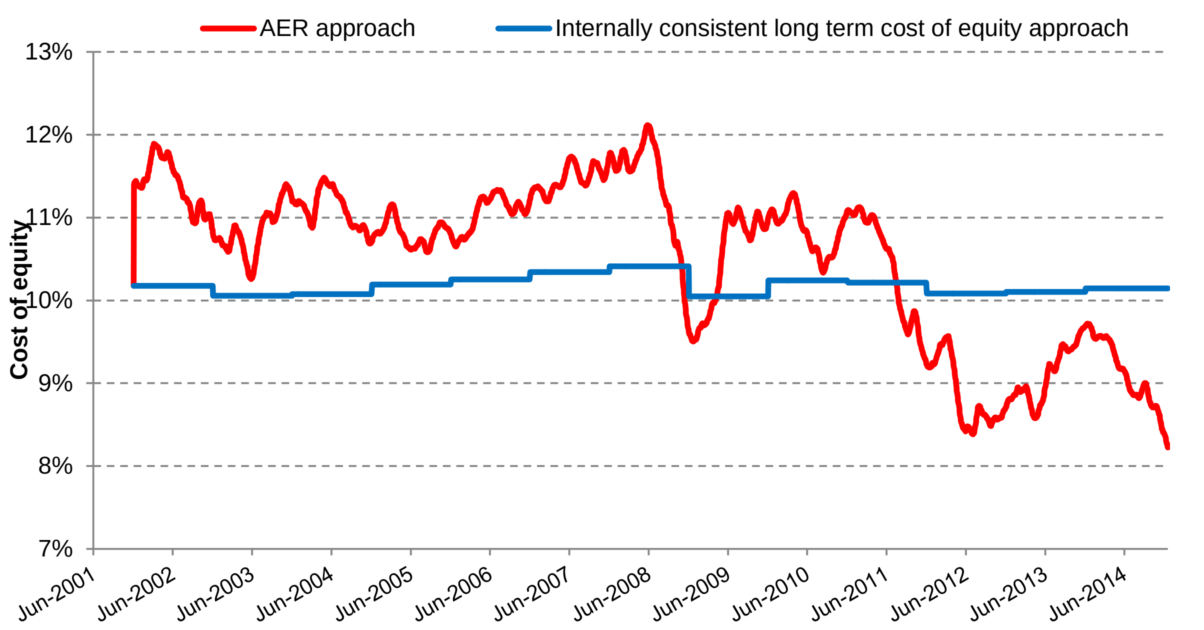
Third, we have estimated the cost of equity for the benchmark firm using prevailing parameter estimates within the DGM, FFM and Black CAPM frameworks. All of these estimates indicate that our proposed estimate of 10.15% is at the lower end of plausible estimates within the reasonable range for the allowed return on equity. Estimates of the required return on equity using these models are discussed further below.

7 ALLOWED RATE OF RETURN

Volatility in the estimated cost of equity

The AER's draft decision states that a short-term averaging period provides a reasonable estimate of the prevailing risk free rate without exposing service providers to unnecessary volatility.[276] We disagree with this statement. As demonstrated below, the estimated risk free rate varies significantly even using a 20 day averaging period. Clearly, using a short term risk free rate and combining this with an MRP estimate based primarily on historical averages produces highly variable results over even a short period of time.

Figure 7c: Movements in the real risk free rate, market risk premium and the real cost of equity over time



Source: Endeavour Energy and NERA analysis.

The estimated risk free rate is at historic lows and combining this estimate with a long term MRP exposes Endeavour Energy to unnecessary volatility and unreasonably low compensation compared with our proposed approach. For example, the AER's draft decision estimated the allowed return on equity to be 8.10% and in just two months from October to December 2014 the return on equity estimated using the AER's approach dropped to 7.63%. This is because the 10 year government bond rate dropped from 3.55% to 3.08% (using the 20 business days to 19 December 2014) and under the AER's approach there is no recognition that the underlying expected return on the market portfolio is unlikely to have changed so significantly. We note that 10 year CGS yields have recently fallen even further, and using a 20 business day averaging period to 14 January 2015, the estimated risk free rate drops to 2.83% and the cost of equity to 7.38%.

By comparison, the return on equity using internally consistent estimates of the risk free rate and the MRP in the SL CAPM provided a return on equity of 9.8% using the 20 business days to 19 December 2014, which only differs marginally compared to the CEG's estimated return on equity of 10.0% using internally consistent short-term estimates of the risk free rate and the MRP from May 2014.

The lower variance in CEG's estimates of the cost of equity using short-term rates illustrates again that at any point in time, the estimated risk free rate may have fallen but investors required return for investing in equities may not have. Indeed it is very likely that during times of financial market uncertainty, rational investors would shift funds into secure assets such as 10 year Commonwealth government bonds. At the same time, the

[276] AER, Draft Decision, November 2013, attachment 3, p. 77

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expected/required return on equities would likely increase to compensate investors for higher perceived risks in the market. CEG makes similar observations.[277]

In contrast to the AER's internally inconsistent approach, our proposed approach has not produced materially different estimates of the required return on equity since our initial proposal. Our initial proposal incorporated an allowed return on equity of 10.11% and our revised proposal incorporates an allowed return on equity 10.15%. This is largely due to our approach of applying internally consistent estimates of parameters as required by the NER, but is also underscored by our approach to consider evidence from all relevant financial models as required by the NER, rather than isolating consideration to one single model.

Wright approach to implementing the CAPM

The AER has characterised the "Wright" model as a separate specification of the SL CAPM. We note that the Wright approach is not a separate specification of the SL CAPM. The Wright approach is an estimation approach for populating the SL CAPM. The approach advocated by Professor Wright is to estimate the expected real return on the market as the historic realised, real return on the market portfolio. We apply expected inflation of 2.5% to this figure to estimate an expected nominal return on the market portfolio, which is one parameter required within the SL CAPM framework. We note that using a long term average of expected/required returns on equity is particularly reasonable when considering investment in long-term infrastructure assets. This approach provides an estimated cost of equity for regulated network firms of 10.25% during the AER's proposed averaging period for the initial return on debt observation.

Endeavour Energy notes that the Economic Regulation Authority (ERA) of Western Australia has recently applied an approach consistent with that suggested by Professor Wright to estimate the required return on equity for rail infrastructure businesses.[278]

Equity beta – empirical estimates

The AER's approach for estimating the cost of equity uses an estimate of the SL CAPM equity beta that relies principally on the AER's prior expectations and equity beta estimates for Australian firms with regulated energy network assets. In our initial proposals and supporting reports we outlined that Australian estimates of equity beta rely on a small sample of listed energy network firms (currently only 4 listed firms remain in the AER's equity beta sample). This small sample size affects both the stability and reliability of the Australian equity beta estimates.

The AER's draft decision dismissed our concerns about the reliability of Australian equity beta estimates given the small sample size, stating that equity beta estimates from its consultant Olan Henry produce consistent results of 0.4 - 0.7 over time.[279] We do not consider that the Australian estimates of equity beta are stable or by themselves statistically reliable over time for the reasons outlined in our initial proposal and supporting attachments.

In addition to this, we note that CEG have conducted further analysis on equity beta estimates for Australian firms. CEG's analysis illustrates that Australian equity beta estimates for non-resources and non-financial firms over the AER's estimation period have been significantly depressed by the impacts of the recent mining boom and the GFC. These major stock market events aren't expected to prevail over the 2014-19 regulatory period so it is questionable whether equity beta estimates materially affected by these events should be used to estimate the allowed return on equity over 2014-19. CEG's detailed findings are outlined in the cost of equity report from CEG, attached with this revised proposal.

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[277] CEG, Estimating the cost of equity, equity beta and MRP, January 2015, - see especially Section 4 and Appendix A.

[278] ERA, Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks – Revised Draft Decision, 28 November 2014.

[279] AER, Ausgrid draft decision, Attachment 3, pp. 258-260.

CEG recommends that based on this new evidence we should reconsider the weight applied to Australian equity beta estimates relative to more statistically reliable evidence using US data over the 2002-2012 estimation period. Applying equal weighting to US and Australian equity beta estimates results in an overall equity beta estimate of 0.85. However we have taken a conservative approach and maintained our initial estimate of equity beta, 0.82, when estimating the benchmark efficient return on equity using the SL CAPM framework

Equity beta – international evidence

Our initial proposal submitted that weight should be placed on the relatively robust empirical estimates of equity beta for US energy network firms. However, the AER's draft decision placed no substantive weight on estimates of equity beta from US firms or other foreign comparators. We note that this is inconsistent with the practice of most regulators in Australia and overseas, the vast majority of which use foreign comparators when estimating the appropriate value for equity beta. The practice of other Australian and overseas regulators in relation to beta is outlined in CEG's report on the cost of equity, attached with this revised proposal.

In foreign jurisdictions that used the CAPM and subsequently derived a beta estimate from a sample of comparators, CEG found that the regulators almost always included foreign firms in their sample. The remaining regulators that did not obtain their own sample of comparators were nevertheless influenced by the equity betas of foreign firms, either by referring to reports from their consultants that were based on data including foreign firms, or by referring to the equity beta decisions of other regulators.

The AER's draft decision stated that the pattern of international results for equity beta are not consistent over time, but that they provide limited support for an equity beta estimate at the top of its empirically estimated range for Australian equity betas of 0.4 – 0.7. We do not consider that this gives reasonable weight to evidence on equity beta from foreign comparators, particularly the relatively statistically robust estimates of equity beta from the US data included in our initial proposal. The evidence from US comparators presented in Endeavour Energy's initial proposal should be used to determine the range for equity beta due to the small sample size for Australian equity betas.

We also note that the AER's draft decision listed a range for international equity beta estimates of 0.45 to 1.14. However, the low end of this range is based on raw equity beta estimates. The range for these estimates once they are appropriately re-levered to a benchmark gearing assumption of 60% consistent with the AER's approach is actually 0.65 to 1.14.[280] Furthermore, as demonstrated by CEG, the 0.65 estimate relies on 1 year of data from 2 UK firms estimated by FTI consulting, which FTI recommended that OFGEM should not into account as it may reflect unusual market conditions. FTI recommended that OFGEM maintain its equity beta range of 0.9-0.95.

Excluding the FTI results for the 2 UK firms (that were ultimately not relied on by OFGEM) provides an estimated range for equity beta from the international evidence of 0.75 (based on a Brattle Group sample of 7 European firms) to 1.01 (based on a Brattle Group estimate for US firms) using average beta estimates, re-levered to the AER's benchmark gearing assumption of 60%. All of this suggests a beta estimate well above the AER's 0.4-0.7 range even before considering what impact the extensive evidence on low beta bias within the SL CAPM framework should have on the final cost of equity estimated using this model.

Low beta bias in the CAPM

There is well established finance literature demonstrating that the SL CAPM under estimates the cost of equity for stocks with a regression based equity beta estimate of less than 1. The academic literature was reviewed in a 2011 report by Professor Bruce Grundy, which concluded that the SL CAPM should be rejected as the true underlying model for explaining returns on equity. The reasons for this include:

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280 We note that re-geared estimates were not possible to derive for estimates used by the Alberta Utilities Commission.

- The empirical regularity that regression based estimates of the SL CAPM equity beta underestimate the measured returns on equity for stocks with a regression based beta estimate of less than 1.
- The required return on a zero beta portfolio is likely higher than the observed risk free rate.

As we noted in our initial proposal, the FFM and Black CAPM attempt to correct for the low beta bias identified by the significant body of empirical research. The following sections outline the estimates from these models and how and why the AER should have regard to the evidence from these models.

7.2.2 Black CAPM estimates

The Black CAPM has both empirical and theoretical support within the academic literature. The AER only has regard to the "theoretical implications" of the Black CAPM. However, the empirical evidence is equally if not more relevant in the context of setting the allowed return on equity. The empirical evidence enables the AER to actually estimate the cost of equity using the Black CAPM and address the low beta bias present when estimating the cost of equity using the SL CAPM framework. This provides an allowed return on equity that is commensurate with the efficient financing costs of benchmark efficient equity with a similar degree of risk as that which applies to Endeavour Energy as required by clauses 6.5.2(b),(c) and (f) of the NER.

The AER's consultants McKenzie and Partington claim that the problem of estimating the benchmark cost of equity within the Black CAPM framework is estimating the return on the zero beta portfolio, which can be very sensitive to the choices made in its estimation. However, even if correct, the sensitivity of zero beta premium estimates to choices made during the estimation procedure should not preclude the AER or others from attempting to estimate the zero beta premium. We note that both CEG and SFG independently attempted to estimate the zero beta in reports attached to Endeavour Energy's initial proposal. The results produced at that time were fairly consistent. CEG has updated its estimate of the zero beta premium and estimates a required return on equity for the benchmark firm using the Black CAPM that remains consistent with both the earlier estimates and SFG's updated estimate of the cost of equity using the Black CAPM.

McKenzie and Partington's conclusion in their report for the AER is that they would not recommend using the Black CAPM alone to estimate the required return on equity, due to difficulties present when estimating the zero beta premium. However, McKenzie and Partington also state that in principle the Black CAPM might be used for estimating the benchmark efficient return on equity in combination with other models proposed by NSPs.[281] We agree with this principle and it is what we have applied in this revised proposal. Given the broadly consistent, independently derived estimates of the zero beta premium from CEG and SFG, we have included estimates for the benchmark efficient cost of equity using the Black CAPM framework in determining our reasonable range for the required return on equity for the benchmark efficient firm.

CEG's updated cost of equity estimates using the Black CAPM are:

- 10.5% using an averaging period for the expected return on the market and MRP of the 20 business days to 19 December 2014.
- 10.7% using an averaging period for the expected return on the market and the MRP consistent with the AER's cost of debt averaging period for Endeavour Energy of 28 February to 30 June 2014.

SFG's updated cost of equity estimate using the Black CAPM is:

- 10.5% using an averaging period consistent with the AER's cost of debt averaging period for Endeavour Energy of 28 February to 30 June 2014.

[281] McKenzie and Partington, October 2014, p. 25.

7.2.3 Fama-French model

The AER's draft decision disregards evidence on the benchmark efficient cost of equity from the Fama-French 3 factor Model (FFM). We consider that the FFM is a relevant model that should be had regard to when estimating the required return on equity, consistent with clause 6.5.2(e)(1) of the NER.

The AER's reasons for disregarding evidence from the Fama-French model as articulated in its draft decision were that:

- the FFM does not appear sufficiently robust and is sensitive to different estimation periods and methodologies
- it is not clear that the model is estimating ex-ante priced risk factors
- the FFM suffers a lack of theoretical foundation
- the FFM is relatively complex to implement.

The SFG report on the cost of equity and the Expert Opinions of Professor Bruce Grundy, both attached to this revised proposal indicate that these issues with the FFM are either not true or are overstated by the AER. Indeed many of the AER's criticisms apply to its foundation model the SL CAPM as well as most financial models used for estimating the required return on equity.

The AER states that the FFM does not appear sufficiently robust. However, we note that there is a significant body of academic research, including at least 20 years of empirical evidence that the FFM performs better than the SL CAPM at predicting stock returns.[282] Further, as noted in our initial proposal, the contribution of the Fama-French Model to improving predictability of stock returns has been recognized by the Nobel Prize Committee in its reasons for awarding the Nobel Prize for Economics to Eugene Fama. These factors indicate the FFM is indeed a sufficiently robust model for estimating the required return on equity that the AER should have regard to, consistent with clause 6.5.2(e)(1) of the Rules.

With regard to sensitivity to different estimation periods, we note that this is equally true for the SL CAPM. As demonstrated in CEG's attached report on the cost of equity, estimates of the SL CAPM equity beta are highly variable over time. In addition to this, as demonstrated above, the AER's estimates of the risk free rate parameter in particular is highly variable over time. This does not prevent the AER from considering the SL CAPM a relevant model to have regard to when setting the allowed return on equity.

The AER's draft decision notes that the FFM is sensitive to estimation methodologies. Again, this is also true for the SL CAPM. As demonstrated by the AER's own analysis in its draft decision, estimates of the MRP parameter that it uses to populate the SL CAPM vary significantly depending on whether a DGM or historical excess return approach is used. This is also true for the equity beta parameter, for which many different estimation methods are available including various regression techniques and the relative risk based approach using DGM estimates of equity returns for energy network firms relative to the market portfolio of stocks.

The AER's draft decision also states that the FFM is not clearly estimating ex-ante priced risk factors and lacks theoretical foundation. In response to this we note the significant body of research showing that the FFM perform well in predicting future stock returns (in fact it performs better than the SL CAPM). This strongly suggests that the FFM framework captures information that is in fact priced into the cost of equity. Professor Bruce Grundy provided the following advice on these points:

> *"it is correct that the Fama French factor models are empirical models in the sense that they seek to describe empirical regularities in the finance data. However, empirical models are at the heart of all science. Newton's theory of universal gravitation was an empirical model designed to fit the empirical observation. Newton discovered within the empirical data, a factor that explained (at least based on the data available to him) the observed strength of gravitational forces. The only*

[282] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p. 2.

theoretical foundation for Newton's theory was that it explained the empirical evidence. There was no theoretical foundation beyond that. Claiming that an empirically derived model should not be relied on because it lacks "theoretical foundations" implies that there is some form of 'truth' which is known and cannot be falsified by empirical observation. In this context it would appear that the AER regards the Sharpe Lintner CAPM model as the relevant source of 'truth'. I do not regard such a position as consistent with the scientific method."[283]

Professor Grundy also outlines that multi-factor models such as the FFM do have a strong theoretical basis. He notes that financial theorists view the empirically derived factors in the FFM as proxies for changes in investment opportunities.[284] The AER's consultants McKenzie and Partington also demonstrate that multi-factor models such as the FFM have a strong theoretical basis in the Arbitrage Pricing Theory, which they attribute to Ross (1976).

Arbitrage Pricing Theory predicts that the return on equity is linearly related to a number of factors. Consistent with Arbitrage Pricing Theory, the FFM assumes that there are factors common to specific stock portfolios that affect stock returns, in addition to the expected returns on the market portfolio. McKenzie and Partington note that the SL CAPM is also consistent with Arbitrage Pricing Theory if it is assumed that the market portfolio is the only common factor affecting stock returns. We note that in contrast to the SL CAPM, the FFM adopts the more realistic assumption that there are additional common risk factors that are being priced by investors.

Finally, the AER's draft decision states that the FFM is relatively complex to implement. However, as noted by SFG in its report on the cost of equity, the FFM model can be implemented using the same approaches used by the AER to estimate parameters within the SL CAPM. Within the FFM:

- The risk free rate can be estimated by reference to 10 year CGS yields
- the market risk, size and value premiums can all be estimated by reference to historical averages
- the betas for the market, size and value premiums can all be estimated by regressions of comparator stocks to returns on the SMB and HML portfolios.[285]

Therefore, the AER cannot disregard the FFM on the basis that it is sensitive to estimation periods and estimation methods used because the SL CAPM faces these very same problems and is not disregarded by the AER. The AER cannot disregard the FFM on the because of a lack of theoretical foundation, because as outlined by Professor Grundy there is a strong theoretical basis for the FFM. In addition, it would not be consistent with the scientific method to simply ignore empirical evidence indicating the FFM does in fact capture ex-ante priced risk factors. Finally, the AER cannot disregard the FFM on the basis that it is relatively complex to implement. The FFM can in fact be implemented using the same estimation procedures applied by the AER to estimate parameters within the SL CAPM.

For the reasons set out above, and consistent with clause 6.5.2(e)(1) of the NER we submit that the AER should have regard to estimates of the required return on equity produced by the FFM. SFG have provided the following updated estimate of the benchmark efficient cost of equity using the FFM:

- 10.8 % using an averaging period for the risk free rate of 28 February to 30 June 2014.

The AER's consultants, McKenzie and Partington state that it is "unclear" whether the FFM, either alone, or in combination with other asset pricing models, would be expected to result in a materially better allowed return on equity estimate. However, their view is that the use of the FFM, alone, would not result in a better estimate of the return on equity. McKenzie and Partington also assert that the FFM's weaknesses are becoming more evident to the point that, given the uncertainties that surround the use of the model, it should not be used for estimating the return on equity.

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[283] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p. 3.

[284] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, pp. 3-4.

[285] SFG, The required return on equity: Initial review of the AER draft decisions, January 2015.

7 ALLOWED RATE OF RETURN

In this revised proposal, we do not propose to use the FFM model alone to estimate the return on equity. We consider that the FFM is one relevant model and that FFM estimates of the required return on equity for the should be considered along with estimates of the required return on equity from the SL CAPM, the Black CAPM and the DGM to develop a reasonable range for the allowed return on equity.

In support of this position, we note that far from weaknesses in the FFM becoming recently evident, the strength of the FFM has become recently evident through recognition by the Nobel Prize Committee for Economics of its contribution to modern finance. We also note that there is a breadth of academic literature demonstrating that the FFM improves the predictability of stock returns and that a number of market practitioners such as the well-respected fund manager, Morningstar, consider the FFM reliable enough to use in practice.

7.2.4 DGM estimates

The AER's draft decision considers estimates of the MRP using the DGM. As discussed above, we consider that this is the internally consistent approach that should be followed when using a short-term averaging period to estimate the risk free rate within the SL CAPM. However, the AER's draft decision only has regard to the DGM based estimates of the expected return on the market. We consider that this approach does not have sufficient regard to DGM based estimates of the required return on equity for a benchmark efficient energy network firm.

As noted by the AER's consultants, McKenzie and Partington, the DGM is reported as the second most popular model used by regulators and the most widely used model for estimating the implied cost of equity from valuation models. We also note evidence from Professor Bruce Grundy, which indicates that dividend discount models are widely used by corporations to determine their cost of capital.[286]

The AER's draft decision states that DGM estimates of the required return on equity are not suitable for any regulatory use for the following reasons:

- The model are not robust given they are highly sensitive to input assumption in relation to the short term and long term growth rate of dividends. This makes the models highly sensitive to potential input errors
- The models are highly sensitive to changes in the risk free rate
- The models may generate volatile and conflicting results

We note that all financial models for estimating the allowed return on equity are sensitive to input assumptions and potential input errors. These factors affect the AER's foundation model the SL CAPM, which can be seen from the sensitivity of the return on equity to the estimate of equity beta. The AER's range for equity beta is wide, 0.4 to 0.7. As demonstrated in SFG's attached report on the cost of equity, the estimated cost of equity is significantly different if an equity beta of 0.4 is adopted compared to when an equity beta of 0.7 is adopted. Furthermore, given the statistical uncertainty around the estimation of beta within Australia, it is also likely that the AER's implementation of the SL CAPM is highly sensitive to potential input errors in its estimate of equity beta. However, rather than ignore estimates of the cost of equity using the SL CAPM, the AER applies judgement to arrive at its estimate. Therefore, we do not consider it appropriate for the AER to disregard estimates of the firm-specific return on equity from the DGM on the basis of sensitivities that equally affect estimates from the SL CAPM.

With regard to sensitivity in changes to the risk free rate, we note that the AER's implementation of the SL CAPM is highly sensitive to changes in the risk free rate due to the internal inconsistency with which estimates of the risk free rate and the MRP. In contrast to this, changes in the risk free rate tend to be offset by changes in the MRP using the DGM. This results in estimates of the return on equity using the DGM being more stable

[286] Letter from Professor Bruce Grundy to Justin De Lorenzo - 9 January 2015.

over time compared with the AER's implementation of the SL CAPM, a point which has been recognized by the AER itself.[287]

The AER states that DGM based estimates of the cost of equity may generate volatile and conflicting results. As noted by SFG, the fact that some DGM based estimates of the required return on equity produce volatile and implausible results does not mean that all DGM based estimates of the required return on equity do.[288] SFG have produced the following updated estimates of the required return on equity for the benchmark efficient energy network firm using the DGM:

- SFG estimate a required return on equity of 10.9% using its construction of the DGM

We consider that it is important to consider all evidence and try to improve the statistical robustness of input variables within any financial model. Although uncertainties will remain, more evidence using reasonable assumptions within independent models is more likely to provide a reasonable estimate than one model alone. This approach is consistent with the requirements of clause 6.5.2(e)(1) to consider information from all relevant financial models.

Under-compensation from the AER's allowed return on equity

The following table illustrates the under-compensation that would result from the AER's approach to setting the allowed return on equity using currently prevailing rates on 10 year Commonwealth Government bonds, relative our proposed approach, which produces a benchmark efficient allowed return on equity of 10.15%.

Table 7.4: Under-compensation from the AER's approach to the return on equity ($m, Nominal)

($m, Nominal)	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Under-compensation due to the AER's approach to setting the cost of equity	$80	$85	$90	$93	$96	**$444**

Note: This is based on an allowed return on equity under the AER's approach of 7.38% (using annualized yields on 10 year CGS over the 20 days to 14 January 2015) compared to our proposed return on equity of 10.15%.

Equity raising costs

In this revised proposal we maintain our initial proposal values for the various components of equity raising costs as outlined in our attached, revised proposal post-tax revenue models.

7.2.5 Value of imputation credits

The NER require an estimate of "the value of imputation credits" (also referred to as "gamma") as an input to the calculation of the corporate income tax building block.[289] Endeavour Energy considers that it is clear that what is required under the NER is an estimate of the value of imputation credits to investors in the business. This interpretation is consistent with the broader regulatory framework and the task set by the NER to determine total revenue, as well as past regulatory practice, and previous decisions of the Australian Competition Tribunal (Tribunal).

[287] AER, Explanatory Statement, Rate of return guideline, December 2013, p. 66.

[288] SFG, Report on the cost of equity for ActewAGL and Networks NSW, January 2015.

[289] NER, clause 6.5.3.

In order to promote the NEO, the estimate of gamma must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate). This is because, although gamma is an input into the corporate income tax calculation, the value adopted for gamma ultimately has a role in determining on returns for equity-holders. If the value ascribed to imputation credits is higher than the value that equity-holders place on them, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity network services for the long term interests of consumers.

The estimation method that the AER proposes to adopt will not result in an estimate of gamma that reflects the value equity-holders place on imputation credits. The AER's method involves the following critical errors:

- the AER's revised definition of theta – which seeks to exclude the effect of certain factors on the value of imputation credits – is conceptually incorrect and inconsistent with the requirements of the NER;
- the AER incorrectly uses equity ownership rates as direct evidence of the value of distributed credits (theta). In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors;
- the AER has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with the evidence in the draft decision;
- the AER uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value;
- the AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors;
- the AER has erred in its interpretation of market value studies. The AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate proposed by Endeavour Energy. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits;
- as well as (correctly) observing that the market-wide distribution rate is 0.7, the AER has also relied on a higher estimate of the distribution rate for listed equity only. Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample;
- the AER's ultimate conclusion as to the value for gamma is inconsistent with the evidence presented in the Draft Decision, including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER has overestimated the value of imputation credits.

The correct approach to estimating gamma is as set out in Endeavour Energy's initial proposal. This involves estimating the distribution rate using ATO data and estimating theta based on the value of imputation credits reflected in share price movements (i.e. using dividend drop-off analysis). Combining the observed distribution rate (0.7) with the best estimate of theta from market value studies (0.35) leads to an estimate for gamma of 0.25. Our revised proposal position on gamma is set out in Attachment 7.07 - Endeavour Energy's revised proposal on gamma. We also note that we have requested SFG to provide further analysis in response to the AER's draft decision on gamma, which was not able to be completed in time to submit with this revised proposal but will be submitted at the earliest possible date prior to the close of submissions on the AER's draft decision, 13 February 2015. The substance of issues to be raised in the SFG report is covered in the attached response to the AER's draft decision on gamma.

8 ALTERNATIVE CONTROL SERVICES

Summary

Endeavour Energy submitted cost reflective prices for the provision of alternative control services. In consultation with councils we capped our public lighting prices at CPI. For the newly classified metering and ancillary network services we sought to create simple, transparent and at-cost prices.

The purpose of this chapter is to identify our concerns with the AER's draft decision on alternative control services, and to make revisions to incorporate the substance of the AER's decisions where we consider necessary.

Our response to the AER's draft determination

This chapter provides our response to the AER's draft decision on each element of our alternative control services proposal:

- **Public lighting** – The AER accepted our proposal on prices for public lighting. The AER's reasons were based on maintaining CPI over the period. Our response is set out in section 8.1 of this chapter;
- **Metering services** – The AER did not accept our proposed prices for metering services. The AER removed the residual asset recovery component of our proposed exit fee from alternative control services by creating a new standard control service, and reduced the administrative component of our proposed exit fee to $0 on the basis that the costs were not proven to be incremental. The AER also made significant reductions to our proposed annual prices for metering services based on its conclusions that our replacement and operating costs were not prudent or efficient, and rejected our proposed upfront meter prices on the basis that they were above the lowest rates identified by the AER's consultant. We do not agree with the AER's assessment and substitute prices. Our response is set out in section 8.2 of this chapter.
- **Ancillary services** – The AER made substantial cuts to our proposed prices for ancillary services. The AER noted that our labour costs were high, overheads were significant and that we had over-estimted the time taken to complete certain services. We disagree with the AER's assessment and have not revised our prices to reflect the draft decision. Our response is set out in section 8.3 of this chapter.

Revisions to our proposal

We have made the following amendments to our initial proposal for alternative control services:

- incorporated revisions to our proposed allowed rate of return set out in Chapter 7 of this document;
- applied new labour escalators consistent with the standard control services forecast;
- applied an updated overhead factor based on the outcomes of the AER approved CAM;
- re-forecast our direct metering services opex based on analysing several years of historic costs and taking into account step changes; and
- developed a new ANS fee for 'meter transfers' which captures the administrative component of the originally proposed exit fee.

8 ALTERNATIVE CONTROL SERVICES

The AER has largely accepted our proposed public lighting prices. Our proposed prices for metering services have been rejected based on the AER's approach to stranded costs and assessment of our forecast costs. The AER has rejected our proposed ancillary network fees in contravention of the CAM for the reasons we clearly highlighted in opposing the change in classification.

In the F&A paper, the AER classified public lighting, metering and ancillary services as alternative control services. These services result in customers receiving an individual price for the service (or category of service) rather than the costs being bundled as part of a network charge. Accordingly, in our initial proposal, we set out our proposed prices for alternative control services.

8.1. Public Lighting

In our initial proposal, we used a methodology similar to that developed by the AER in the previous period to develop our proposed public lighting prices. We considered the capital, operating and implementation costs of providing elements of our service. Based on the current number and mix of street lights for each council, our plan was to keep our increase in the total streetlight bill to CPI for the 2014-19 period.

In its draft decision, the AER largely accepted our public lighting prices. The AER noted:

> *"In reviewing these inputs we consider the following benchmarks to be appropriate:*
>
> - *a 4 year bulk replacement program for all lamps. Currently Endeavour Energy has a 4 year cycle for high pressure sodium lamps with wattages of 150, 250 and 400. For all other lamps it is three years.*
> - *a WACC of 7.15 per cent instead of the proposed 8.83 per cent*
> - *a useful life of 20 years for LED lumenaires instead of the proposed 12 years*
> - *labour escalators consistent with our decision (opex chapter)"*[290]

The AER also noted that:

> *"Whilst the NSW Public Lighting Code sets standards for distributors to adhere to, it is only voluntary. We see our role as setting a minimum level of protection. Negotiation between councils and Endeavour Energy can secure lower prices than those set by our determinations but councils must recognise that the trade-off will be a lower level of service offered by their distributor. Or a higher price for a tailored level of service."*[291]

We have concerns with the AER's commentary on confidentiality and our relationship with our public lighting customers. We undertook an extensive consultation process with our councils and found that they:

- accepted our commitment to cap prices at CPI;
- wanted service levels to be maintained according to the Public Lighting Code; and
- considered LED technology an important future state to work towards.

There were over 50 stakeholder submissions regarding public lighting proposals of the NSW DNSPs, only 4 of these pertained to Endeavour Energy. Whilst half of the submissions discussed regulatory matters regarding the AER's classification of services in the F&A paper, Endeavour Energy did engage with our councils to discuss the initial proposal prior to its submission.

[290] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 50

[291] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 56

Our discussions did not indicate that councils had substantive concerns with our confidentiality claims or public lighting model. We acknowledge that the model can be complicated to understand which is an unfortunate consequence of the regulatory framework. However, we sought to submit a fully functional version of the model with our proposal that could be used to add and price new public lighting tariffs by stakeholders. We will continue to engage with our customers with any questions or assistance they require in this regard.

Regarding engagement with councils and overall service outcomes, in its draft decision the AER noted:

> *"The minutes of Endeavour Energy's meetings with councils indicate a general level of satisfaction from councils in relation to the service provided and consultation being undertaken by Endeavour Energy."*[292]

The sections below address the matters raised by the AER in the draft decision in respect to public lighting services. Our revised model and prices for public lighting are at Attachment 8.01.

8.1.1 Cost of capital

In Chapter 7 of this revised proposal Endeavour Energy set its revised proposal for the cost of capital having taken account of the AER's draft decision and other feedback provided.

We have made consequential revisions to our public lighting prices to take into account our revised cost of capital.

We also note that in the draft decision the AER did not fully update the cost of capital parameters in the Endeavour Energy model used as the basis for the draft determination. Endeavour offers its assistance to the AER when making the final determination to ensure that the public lighting model is consistent with the AER's cost of capital decisions.

8.1.2 Labour escalators

In Chapter 6 of this revised proposal Endeavour Energy revised the real cost escalators to apply to labour costs over the forthcoming regulatory control period, having accepted the averaging approach taken by the AER in the draft determination.

The proposal for public lighting prices has been revised to take into account the consequential impacts on our proposal of the real labour cost escalators being proposed for standard control services, including the updating of data relevant to the averaging approach included in the AER's draft determination.

8.1.3 Serviceable life of LED lumenaires

In the draft decision the AER proposed to amend Endeavour Energy's proposal for serviceable life for LED lumenaires to 20 years in preference to the 12 years proposed. As set out by the AER this was based primarily on comparisons with the lives used by other DNSPs for LED technology. Specifically the AER stated in the draft decision that:

> *"Propose a 12 year life for LED lumenaries compared to 20 year useful life for all other lumenaire types. Whilst this is emerging technology, evidence suggests a long life of 15 to 20 years or longer for this technology. This is also consistent with Ausgrid's proposed life of 20 years for LED lumenaries. We consider a useful life of 20 years to be appropriate."*[293]

[292] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 54

[293] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, pages 55-56

8 ALTERNATIVE CONTROL SERVICES

Endeavour Energy has not revised our proposal in consideration of the AER's draft decision and submissions from stakeholders. We consider the 12 year economic life proposed previously better reflects the expected serviceable life of the assets installed on our network as provided by manufacturers.

Endeavour Energy's LED tariff has been based on an expected life, and therefore a capital cost recovery period of 12 years, as opposed to the standard 20 year life expectancy of other lumenaires in the model.

A range of factors were considered in selection of this value, including: quality and range of data from manufacturers; Endeavour Energy's pricing formula; and financial risk to both Endeavour Energy and our public lighting customers.

A review was undertaken of nine major LED manufacturers' publicly available datasheets for LED lighting. At Attachment 8.03 - LED Data sheets - Endeavour Energy has collated a range of information sheets from LED suppliers for LED lumenaires currently available in the market. The datasheets, summarised below, illustrate that the indicative life expectancy ranges between 11.4 and 22.8 years (based on lumen loss), with the vast majority of manufacturers stating a life of marginally below 12 years.

Table 8.1: Indicative lives of LED lumenaires as provided by major manufacturers

Brand	Indicative Life	
	Hours	Years
GE	50,000	11.4
Nikkon	50,000	11.4
Osram	50,000	11.4
Remis	50,000	11.4
Samsung	50,000	11.4
Philips	60,000	13.7
LED innovations (Cooper)	60,000	13.7
Gerard (Sylvania)	88,000	20.1
Pecan	100,000	22.8

Endeavour Energy considers LED lighting technology to be the future direction of public lighting in Australia. Due to the rapidly changing technology associated with LED lighting; the public safety service offered by public lighting; the lack of proven long-term reliability data; and the large range in manufacturer's life expectancies Endeavour Energy cannot substantiate using a 20 year capital recovery period.

Further investigation has been conducted into the 20.1 year life expectancy stated by Gerard. Since Gerard's LED product is a combination of a Samsung LED unit and Samsung/Phillips power supplies; the increase in expected life from the actual parts manufacturer (11.4 and 13.7 years) was queried. To date no substantiated reasoning for this increase in claimed life has been provided to Endeavour Energy despite this request.

The life expectancy data available for LED public lighting predominately focuses of the lighting level outputs vs burning hours and negates other failure modes (including driver circuitry and component failure). AS/NZS 1158.1.2, clause 14.3.2 clearly states that "manufacturer data on lamp mortality rates is derived from laboratory tests in controlled environments and as such can be taken as a guide". The document also highlights that "the reliability of the curves decreases as the number of burning hours increases". Considering the data is based on testing generally between 8 and 20 months, extrapolation of life to 240 months (20 years) is questionable.

Endeavour Energy's public lighting pricing model predominantly takes actual costs to the organisation distributed across the lighting tariffs, rather than the bottom up approach used by other DNSPs. To move to a 20 year life expectancy for LED streetlights the model would need to incorporate an additional assumed failure rate to account for the inevitable increase in early failures during the 20 year period requiring remediation to ensure the minimum public lighting safety standards are maintained.

Due to the quality and range of data associated with such a failure rate from different manufacturers, Endeavour Energy does not believe it to be in the customer's long term interest to place a high level of reliance on such data. Increasing the capital recovery period to 20 years would require further assumptions in the pricing model to be made including not only an expected failure rate, but also an expected population of LED lights for each year in the regulatory period. At this stage it is difficult to predict the population growth of LED's as a number of councils are proposing to implement a large scale LED role out, to replace existing public lighting. Information associated with this proposed role out is unclear for the next 12 month period, let alone the regulatory period.

Endeavour Energy believes a 12 year capital cost recovery for LED Street Lighting assets to be prudent, transparent, and balances both technical and financial risks for Endeavour and our customers as LED lighting is increasingly introduced into the network. The economic life assumption accounts for the expectant life published by the majority of LED manufactures; the uncertainty of the reliability associated with the electronics within the units; the manufacturers' ten year warranty period; and the public safety risk posed by lumenaires functioning below the safety specifications.

Finally, this revised proposal is based on data provided by a number of manufacturers of the equipment being assessed as it is verifiable. As such, Endeavour submits that the assessments of the manufacturers in this instance has priority over any benchmark of lives used by other DNSPs which may utilise differing pricing model approaches.

In conclusion the NSW DNSPs understand there is significant uncertainty to the expected asset lives for LED lighting. In modelling these assets to calculate the annuity charges for these LED lights, different approaches have been undertaken. Ausgrid has applied a 20 year economic life with 20% of all lights replaced during this period (assuming more risk for the DNSP, to better manage customer prices), while Endeavour has applied a 12 year life with no replacements modelled over this period to avoid future step changes given the uncertain technology.

It is Endeavour Energy's belief that the adopted approach will provide the appropriate level of safety and reliability that our customers seek.

It is also notable that Endeavour Energy has recently approved an additional LED lumenaire for service within its network area as standard lumenaries that it will support. The proposed prices and lives for this additional lumenaire has been included in the updated public lighting model at Attachment 8.01 (Confidential). The lives and costs have been established based on the specifications obtained by Endeavour Energy from the respective manufacturers and the relevant contract rates that have been offered. This is set out in Attachment 8.02.

8.1.4 Bulk lamp replacement cycles

In the draft decision the AER did not accept the differentiated bulk lamp replacement (BLR) cycles proposed by Endeavour Energy. Specifically the AER stated that:

> *"In relation to setting public lighting charges, we consider a four year bulk lamp replacement program that applies in Victoria as the appropriate benchmark."*[294]

[294] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 54

8 ALTERNATIVE CONTROL SERVICES

Endeavour Energy does not agree with the proposed use of a blanket benchmark approach with other DNSPs for several key economic, compliance and public safety reasons.

Bulk Lamp Replacement Cycle Costs

Endeavour Energy's current bulk light replacement (BLR) strategy is based on a detailed review of BLR cycles conducted in July 2013. The review conducted a cost benefit analysis of completing Endeavour Energy's BLR at 0.5 year increments between 2.5 and 4.0 years. The analysis compared the costs of the BLR program (at each frequency) with the expected increase/decrease of spot failures (based on manufacture mean time to failure data). The analysis was undertaken as part of Endeavour Energy's broader efficiency improvement programs, and was therefore designed to seek out the lowest cost BLR cycle.

The analysis identified that the most economic BLR frequency is highly dependent on the current population of different lighting technologies within the network area. Consequently, the analysis focused on the eight lighting technologies most prominent in Endeavour Energy's network (in July 2013) that is a representative sample of our public lighting fleet.

The findings of the analysis is contained in confidential Attachment 8.03 (Confidential), however the substance of the analysis is replicated in the table below:

Table 8.2: Results of economic analysis of different bulk life replacement cycles

Bulk Lamp Replacement (BLR) Cycle	Annual expense % (Relative to 3yr cycle)
2.5 year cycle	101%
3.0 year cycle – (cycle at time of review)	100%
3.5 year cycle	107%
4.0 year cycle	112%
Hybrid: 4 year cycle for sodium lamps and 3 year cycle for all other lamps	97%

As can be seen from the table above, the review demonstrated that for Endeavour Energy's current public lighting population a hybrid three to four year strategy was the most cost effective. In addition to the High Pressure Sodium lamps that are identified as being more cost effective at a four year cycle, two other lamps types (14W and 24W T5) could also benefit from a four year cycle. However, due to the relatively low numbers of these lamps and their dispersed geographical location throughout the network it is not practical or financially viable to move these lamp types to a four year cycle at this point in time.

Proposals to move Endeavour Energy's BLR to a fixed four year frequency for all lighting technologies will either increase the costs associated with spot failures to the point that any savings associated with the increase to the BLR are negated, or cause Endeavour Energy's public lighting network to be non-compliant with the requirements of the relevant Australian Standards for lighting levels.

Based on the available evidence, Endeavour Energy considers the proposed hybrid three year and four year BLR to be the most economical delivery method to ensure street lighting customers are provided with a compliant and reliable service. Further, the evidence demonstrates that if Endeavour Energy were to accept the AER's draft decision on the BLR cycle then the annual costs of the public lighting business would result in a net cost increase of over 10% that would then need to be passed onto our customers.

With the increased introduction of new public lighting technologies into the network this analysis will be periodically reviewed to ensure the most economic BLR program is maintained. Endeavour Energy will therefore continue to monitor the BLR frequency against its population of public lighting assets to ensure this is achieved.

Bulk Lamp Replacement Cycle Safety Outcomes

The serviceable life of lamps is defined by reference to not only the continued physical operation of the lamp but also by the lumen output of the lamp over time. Predominately, it is the degradation of the lumen output that will determine the serviceable life of lamps within the fleet of public lighting installations. Understanding the speed and level of lumen degradation over time is critical for establishing the replacement lifecycles for lamps to ensure ongoing and effective public safety service that public lighting provides.

In Australia, AS/NZS 1158 establishes the minimum lumen requirements for a range of public space settings. It is to these standards that Endeavour Energy is required to comply in order to discharge its safety obligations to the community at large and to manage the risk exposures of non-compliance on behalf of our customers, i.e. the councils.

Endeavour Energy has had regard to the lumen output degradation pattern of the various lamps in service to determine BLR cycles that will ensure compliance with the standard.

Endeavour Energy is concerned that failure to comply with Australian safety standards will expose the councils to risks in the event that an event occurs causing damage to property or person that is the consequence of below standard lumen output. Consequently, Endeavour Energy has concerns regarding the impacts of an economic judgement being applied by the AER to this matter of public safety without the AER also undertaking a safety risk assessment.

Therefore, if the BLR were to be moved to four years for all lighting technologies public lighting customers would need to be informed and formally accept that the lighting levels will at times become non-compliant with the relevant Australian Standards and accept the resultant risk and liability exposures.

8.1.5 Engagement with Councils

Endeavour Energy had, and has continued to have good engagement with councils and ROCs since it lodged the initial proposal. These engagements have included ongoing updates to the regulatory process, price expectations, feedback on our service levels and exploration of alternative arrangements to facilitate councils to adopt LED technologies.

The feedback received by Endeavour Energy regarding these engagements has been positive, and Endeavour Energy anticipates that this engagement will continue to assist Endeavour Energy in ensuring that it is able to provide its customers with value for money services.

8.2. Metering

Our proposed prices for metering services were intended to provide a transparent and cost-reflective price signal to customers whilst transitioning to an environment of increased competition. Our prices were based on the meter service a customer is receiving. To develop cost reflective prices, we examined our historical costs to determine the drivers of metering costs. This included recovering the costs of existing meters, new meters, and operating and replacement costs.

The AER did not accept our proposed metering prices and approach. The AER were of the view that our costs were overstated and our exit fee was a barrier to competition. Specifically the AER stated:

> *"Our decision does not accept Endeavour Energy's:*
>
> - *annual metering service charge because the forecast capital and labour costs do not reasonably reflect the efficient costs of a prudent operator*
> - *price caps for new and upgraded connections for similar reasons*
> - *proposal to charge an exit fee to leaving customers to recover residual metering costs. Instead residual metering costs will be classified as a standard control service and*

> *recovered from the general network customer base to avoid creating a regulatory barrier to competitive entry."*[295]

In addition to these key points the AER accepted our approach of a single price for both new and existing customers, although a preference for separate prices was articulated. Additionally, the AER rejected our pricing approach of expensing replacement meters and accelerating the depreciation of the existing metering asset base. In applying a price cap form of control for metering the AER set the X-factor to zero for Endeavour Energy.

Endeavour Energy has not revised its proposed prices to adopt those outlined in the AER's draft decision. Rather, we have revised our proposed prices to reflect an:

- update to our direct operating expenditure forecast, which draws on several years of historic results and known step changes; and
- updated labour escalators consistent with the AER's draft decision for standard control services and applied a new overhead factor based on the results of the AER approved CAM.

In doing so, we have not revised our pricing approach or methodology as we consider this produces a transparent and cost-reflective price whilst removing long term barriers to competition. Refer to Attachment 8.04 to this proposal for the updated annual metering prices.

8.2.1 Exit fees

As discussed above, the AER rejected our proposed approach and prices on the basis that the exit fee was anti-competitive (for the recovery of residual asset costs) and not reflective of the incremental administration costs Endeavour Energy would incur.

At the outset, we wish to clarify that our classification proposal did not propose 'an additional metering service called metering exit fee' as the AER contended. Our initial proposal accepted the AER's classification of type 5-6 metering services and accordingly, our initial proposal sought to propose a cost reflective price for these services. The exit fee was the means by which we proposed to recover the costs associated with the provision of type 5-6 metering services. This fee is triggered when a customer, who up until that point has been receiving metering services from Endeavour Energy, decides to switch to an alternate metering service provider. This decision to switch gives rise to the stranded cost (residual capital cost) and administration cost.

The AER has proposed that a new standard control service be created to allow DNSPs to recoup the stranded asset costs created by competition at the time a customer obtains an alternate metering service provider. The existing asset base would be recovered from annual metering charges. If the customer chooses to have a third party provided meter replace the existing meter an amount (equal to the residual value of the asset) will be recovered via an adjustment to standard control services. In its draft decision the AER stated:

> *"We do not accept Endeavour Energy's proposed exit fee. Specifically, we do not accept that Endeavour Energy should recover residual capital costs through an exit fee. Our alternative is to classify residual metering costs (the capital costs the customer would have paid through annual charges had they remained a regulated metering customer) as a standard control service and will be recovered through network tariffs."*[296]

In light of Endeavour Energy's relatively small existing asset base we consider this may represent an administratively burdensome solution to address an immaterial issue. The asset based portion of the proposed exit fee ranges from $14-$3 from years 1 through 4 respectively. However, we are supportive of facilitating competition in metering services provided the AER has satisfied itself that this is not creating an artifically competitive market, and is a pragmatic, compliant and simple solution.

[295] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 61

[296] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 28

As such, we have revised our proposal to adopt the AER's approach and therefore excluded residual asset costs from the proposed 'meter transfer fee'. However, as outlined in Chapter 9 to this revised proposal we do not accept the AER's tolerance limit for the metering component of the b-factor adjustment unless the unrecovered amount can be carried forward to the next regulatory control period. It is an efficient, approved cost that forms part of our RAB, it would be inappropriate to deny the recovery of this revenue if it were to exceed the 2% limit. The timeline associated with the AEMC rule change process may result in material adjustments late in the 2014-19 period. We contend any residual amounts (which would be small for Endeavour Energy) are carried forward as required.

In regards to the administrative component of the proposed exit fee the AER has accepted the principle of a fee, specifically a 'meter transfer fee', but rejected our proposed fee:

> *"While we accept in principle that Endeavour Energy should recover incremental administration costs through an exit fee, we do not consider that Endeavour Energy demonstrated they will face incremental administration costs. As such, we do not accept that an exit fee should apply."*[297]

We have revised our ANS price list to adopt the decision to create an ANS 'meter transfer fee'. In response to the matters raised by the AER we have reviewed our proposed meter transfer fee and revised it. Specifically, we have sought to better understand and justify the activities involved in transfering a metering customer and the cost involved. However, we do not consider that the cost should be "incremental" to be justified. This requirement does not apply to any other ANS fee.

In developing a rate for a 'meter transfer fee', a detailed process review has been conducted to capture the end to end meter removal process for Type 5 & 6 metering, outlining the administration costs associated with performing the required activities. As such, our revised metering transfer cost is as follows

Table 8.3: Component tasks involved in a meter transfer process

Task	Time	Hourly rate (inc on-cost & overheads)	Cost per meter ($2014-15)
Administration Officer updates the meter removal in the Meter Provider Database	5 min	$64.20	$5.35
Network Billing Data Analyst updates the meter removal and the new metering details (for the non-Endeavour Energy asset) in the Banner billing system	5 min	$86.73	$7.23
Network Billing Data Analyst updates the new metering details in the Metering Business System (MBS), which will allow network billing activities to occur	5 min	$86.73	$7.23
Metering Officer obtains the final read for the meter and inputs the details of the final read into Banner	5 min	$79.39	$6.62
The ASP returns the Endeavour Energy removed asset back to the designated Endeavour Energy depot. Endeavour Energy process dictates that the meter is double bagged and goose necked to ensure safe transportation of asbestos contaminated materials. The consumables required to meet these requirements are supplied by Endeavour Energy		Materials	$1.24
Cost of meter disposal		Contractor	$1.00

[297] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 28

Task	Time	Hourly rate (inc on-cost & overheads)	Cost per meter ($2014-15)
Total direct cost			$28.66
ANS overhead factor (from CAM)			126.5%
Meter Transfer Fee (per meter)			$64.91

Refer to fee methodology 'meter transfer fee' (Attachment 8.05) to this revised proposal for further detail.

In addition to our revised position we also note that the AER's consultant Marsden Jacob provided a benchmark 'meter transfer fee'. This recommendation was not adopted by the AER in its draft decision, despite the report being heavily relied upon for all remaining ANS fees. Marsden Jacob noted:

> *"Marsden Jacob recommends that the total labour rates which apply to administration processing of meter exits should be capped at $89.06. The total labour rate proposed is consistent with market salary rates for administration and processing positions and includes standard on-costs and overheads of 50%. This rate is consistent with the benchmarked labour rates proposed by Marsden Jacob for Ancillary Network Services (refer to 1.1.4).*
>
> *We also recommend that the time taken to perform each exit should, on average, be capped at 0.40 hours. In making the recommendation, Marsden Jacob consider the time taken to perform other metering services including special meter reads, disconnection services and meter equipment tests. Times proposed by the NSW and ACT distribution businesses for the current determination process were considered as well as the accepted time taken for back-office aspects of services in the most recent Victorian regulatory determination. As the exit process is yet to be fully defined and the actual time needed to process changes is unknown, Marsden Jacob's recommendation is to accept the lower rate proposed by the two distribution businesses at this point.*
>
> *Marsden Jacob notes that a SA Power Network's current exit fee for customers consuming above 100MWh transitioning from type 6 ACS metering service into the competitive market includes an administration component of around $60.00 ($2010)."*[298]

We consider it unreasonable to have rejected our proposed fee and set it at $0 when an alternative, independent estimate was available. This consultant advice further supports the legitimacy of a meter transfer fee.

Therefore, we consider it would be unreasonable for the final decision to set the fee at $0 in light of the further justification we have provided to support our revised fee and the benchmark rate provided by the AER's consultant.

8.2.2 Replacement capital expenditure

In developing alternate annual metering prices the AER made significant reductions to Endeavour Energy's proposed metering capital expenditure program. Specifically, the AER stated:

> *"We do not, however, accept Endeavour Energy's proposed capital expenditure building block. Our draft decision accepts $8.1 million in capital expenditure for annual metering charges and substitutes that amount for Endeavour Energy's proposed $21.1 million ($2014-15)."*[299]

[298] Marsden Jacob Associates, Advice prepared for the AER: Provision of advice in relation to Alternative Control Services – Final, 20 October 2014, page 20

[299] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 28

The primary reason for this reduction was that the AER considered our forcast replacement volumes to be overstated:

> *"We consider Endeavour Energy's proactive forecast of 130 077 meters to be overstated. It includes 108 671 meters which have yet to fail compliance testing. For these meters, Endeavour Energy acknowledged that the forecast 'is only based on assumptions on the current engineering judgment for Endeavour Energy's meter population that are likely to fail in the near future'. We do not consider this to be sufficient justification and so we substitute the forecast 130 077 replacements with an amount equal to the number of meters which have actually failed compliance testing (21 406). In its revised regulatory proposal, we expect Endeavour Energy to provide additional information explaining why it considers part, or all, of the remaining 108 671 meters should be replaced."*[300]

Endeavour Energy has not revised its regulatory proposal to adopt the AER's substitute forecast, however we have revised our metering capex forecast to address the matters raised by the AER. We consider that proactive replacement is prudent and upon more detailed review of the replacement program, based on an additional year's worth of information and information provided by other DNSPs, we have revised the program.

The AER's position to remove 108,671 meters from the program is unreasonable. Firstly, the AER has approved bulk replacement programs for other DNSPs in previous determinations and their draft determination for the other NSW DNSPs. Secondly, it is unrealistic to simply assume that all meter populations that have not currently failed will not fail within the next four years. This will remove the DNSPs ability to comply with its metrology requirements as defined in the NER (i.e. upon failure and non-compliance of a meter type population the assets may need to remain in service for a further four years prior to replacement). This decision also fails to consider the relationship between proactice and reactive replacement by removing 108,671 meters from the proactive program whilst making no revision to the reactive program.

Based on the latest available information we have revised our replacement program. This proposal has been updated for meter type populations which have failed testing and have been included in the latest MAMP provided to AEMO (including an update to the population of those meters). It also includes projections of future populations that are projected to fail over the period, but only populations that have already failed in the other Networks NSW businesses. As these meters are the same devices and similar ages in all businesses it is exceedingly likely that these populations will fail in Endeavour Energy when tested. The table below details the meter populations within our proactive program and outlines where we have revised our proposal.

Table 8.4: Initial and revised meter replacement program

Meter make and model	Scheduled replacement	Initial Proposal	Revised Proposal	Justification
Failed				
SD three phase WC (up to 6 series)	2014–15 to 2015–16	16,082	12,256	AER data transfer error and updated from latest MAMP
M1 single phase WC 61–65	2016–17	452	447	Updated from latest MAMP
SDM three phase WC 96–00	2016–17	3,995	3,059	Updated from latest MAMP
Calmu three phase WC	2016–17	684	458	Updated from latest MAMP
Calmu three phase CT	2016–17	4	0	Updated from latest MAMP

[300] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 40

Meter make and model	Scheduled replacement	Initial Proposal	Revised Proposal	Justification
Failed				
Sprint three phase WC	2016–17	187	0	Updated from latest MAMP
SD 2p WC		0	4,122	Updated from latest MAMP
SDM 2p WC		0	2,666	Updated from latest MAMP
SDM 3p WC 1986-1990		0	5,578	Updated from latest MAMP
SDM 1p WC 1996-2000		0	239	Updated from latest MAMP
Subtotal		21,406	28,825	
Likely to fail or have failed at other DNSPs				
WF3 1p WC	13–14	84,401	0	Accept AER view
SDM 2p WC 96–00	13–14	250	0	Accept AER view
SDM 3p WC 66–85	14–15	23,484	0	Accept AER view
HMT 1p WC	15–16	7,898	7,496	Failed at Ausgrid and Essential Energy
SDM 3p CT 51–00	15–16	1,471	0	Accept AER view
SD 3p WC (6 series above)	16–17	11,515	11,311	Failed at Ausgrid and Essential Energy
BAZ 1p WC	17–18	51,158	48,017	Failed at Ausgrid and Essential Energy
WF2 1p WC	17–18	11,992	11,552	Failed at Essential Energy
Likely to fail or have failed at other DNSPs				
SD 3p CT	17–18	127	0	Accept AER view
SDM 2p WC 76–80	17–18	592	0	Accept AER view
SDM 2p WC 86–95	17–18	52	0	Accept AER view
SDM 3p WC 91–95	17–18	382	0	Accept AER view
Subtotal		193,322	78,376	
Total		**214,728**	**107,201**	
Total compliance replacement		**130,077**	**80,792**	**Note: the remainder will be replaced post 2014-19**
Reactive replacement		17,417	17,417	Approved in draft determination
Total replacement program		**147,494**	**98,209**	

As a result, we have revised our metering capital program (prior to WACC application) downwards by $3.8 million ($2013-14) over the 2014-19 period from $18.0 million to $14.2 million, a reduction of 21%.

8.2.3 Operating expenditure

In addition to the reductions to our proposed capex the AER has made significant reductions to our metering opex in establishing alternative prices. The AER has primarily relied on benchmarking to reject and substitute our proposed opex, specifically noting:

> *"We substitute Endeavour Energy's proposed operating expenditure building block of $103.4 million for annual metering services with $67.9 million ($2014–15). This is a 34 per cent reduction from the proposed amount. Though significant, it reflects the same downwards trend as our adjustment to Endeavour Energy's proposed operating expenditure for standard control services. And while we would not necessarily expect a uniform reduction across metering and network services, there are strong commonalities as it is the same organisation with the same labour force."*[301]

We consider the AER's position is unreasonable. The AER considers that a similar reduction should be made to metering as the reduction applied to standard control services opex. Despite this, a reduction of 34% has been made by the AER, a reduction that is 11% higher than the 23% reduction made to standard control services. Sufficient justification is not provided as to why such a significantly higher and different reduction is required for a service the AER considers is materially similar.

The AER then assessed our proposed expenditure against the historical expenditure and considers an inefficient increase exists:

> *"Using an historical average from 2008–09 to 2012–13, we observed a base expenditure of $17.3 million ($2014–15). This is less than Endeavour Energy's proposed average annual operating expenditure allowance of $20.7 million ($2014–15).*
>
> *…. However, we observed that in the 2014–19 regulatory control period, Endeavour Energy proposed to spend on average, $22 per customer ($2014–15) in operating expenditure. This is slightly higher than its historical expenditure from 2008–09 to 2012–13, which averaged $20 per customer ($2014–15)."*[302]

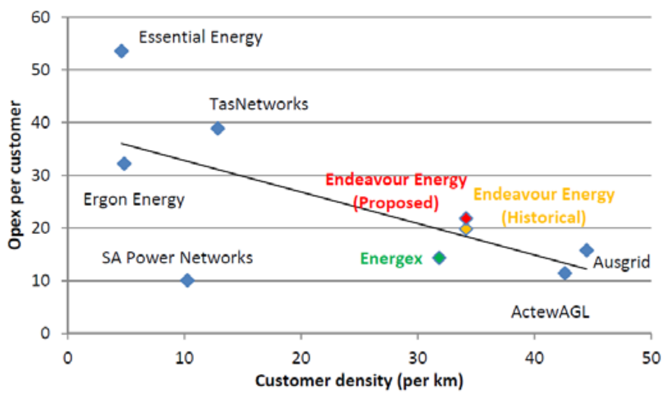
Despite this observation, the AER's substitute amount is approximately $3.9 million ($2013-14) per annum below the historical expenditure without detailed explanation or justification as to why such a large annual reduction is appropriate or even achievable. Instead, the reduction appears to rely solely on high level benchmarking analysis:

[301] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 40

[302] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 41

Figure 8a: AER Benchmarking Analysis from Alternative Control Service Decision

Figure 16-5 Benchmarking of operating expenditure per customer ($ 2014–15)



This analysis suggests Endeavour Energy is only slightly above the “frontier”. This is not to say we consider the measure is accurate or reliable, rather this measure assumes customer density is the key driver of metering opex and that the metering services provided are similar. A linear relationship is assumed to chart the frontier which is contrary to the AER’s application of benchmarking in its Annual Benchmarking Report. The strength and relationship of this function is not disclosed or understood by the AER and unquantified factors exist which have not been detailed or accounted for. Despite these limitations, the AER have selected the nearest lowest cost DNSP as a benchmark for Endeavour Energy:

> *“Our benchmarking results, therefore, show that Endeavour Energy’s proposed operating expenditure to be overstated. To more reasonably reflect a relatively more efficient business running a network with Endeavour Energy’s characteristics, we substitute the proposed base operating expenditure with an amount equal to Energex’s per customer spend. This is just a relative efficiency adjustment as it is based on Energex’s revealed costs alone, without actually assessing the efficiency of its base operating expenditure which we will undertake when making the Queensland 2015–2020 electricity distribution determination.”*[303]

We do not consider the benchmarking results confirm this view nor do we consider it reasonable to assume it is of sufficiently robustness and accuracy to be relied upon to the degree that the alternate methods are ignored. Refer to section 5.4.3 and 6.4.2 of this proposal and attachments 1.01 to this proposal for further analysis of the AER’s benchmarking.

Furthermore, we do not consider Energex represents a reasonable comparator to Endeavour Energy for the following reasons:

- the number of customers that Energex services enables economies of scale that Endeavour Energy cannot access with our metering service;
- there are cost of living differences between QLD and NSW that will impact the labour rates for Energex and Endeavour Energy;
- customer density is not the sole driver of metering costs and other organisational and environmental differences exist between Energex and Endeavour Energy that are not accounted for; and
- it appears Energex have only allocated a small portion of overheads to metering. On a direct cost basis Endeavour Energy compares favourably. The measure may be capturing differences in cost allocation methodologies rather than efficiency.

[303] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, pages 42-43

Whilst we consider the AER's assessment and substitute amount unreasonable we reviewed our opex forecast to determine whether a more suitable forecast methodology could be utilised. As a result we have revised our forecast to reflect the most up to date information (i.e. additional year of actual data and labour escalators), take into consideration several years of historical costs rather than a single year and to reflect step changes created by NECF and asbestos compliance obligations. These latter changes have introduced new obligations from 2013-14 onwards.

Table 8.5: Revised forecast metering opex comparison to initial proposal

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Initial Proposal	19.4	19.7	20.4	20.5	20.9	**100.9**
Revised Proposal	19.2	21.3	21.4	22.1	22.1	**106.1**
Difference	(0.3)	1.7	1.0	1.6	1.2	**5.2**

This revision acknowledges that of the assessment methods used, we consider the historical comparison a valid approach given the recurrent nature of opex and the growing metering customer base. Therefore, to develop this revised forecast, Endeavour Energy adopted the following methodology:

- Obtained type 5 & 6 metering direct opex for the period 2008-09 to 2013-14 from audited Reset RIN and Category Analysis RIN data and calculated a direct opex rate per type 5 & 6 metering service;
- Applied the average direct opex rate for the 2008-09 to 2013-14 period to the forecast number of type 5 & 6 metering services to the 2014-19 period;
- Included positive step change adjustments relating to recently adopted NECF and asbestos management compliance obligations in order to calculate revised direct opex;
- Included negative step change adjustments relating to special meter reading and meter accuracy testing opex which was included in the historic expenditure. These amounts need to be excluded as they are captured within ANS forecast opex;
- Applied new labour escalators, consistent with revised standard control services opex; and
- Included the outcomes of the AER approved cost allocation methodology in relation to network and corporate overheads applied to type 5 & 6 metering services.

This above method is explained in more detail in the updated metering model, Attachment 8.05 to this revised proposal.

Additionally, in its draft decision the AER noted that a negative step change may be required for metering to account for the ANS costs that may be embedded in historical metering opex:

> *"Therefore, historic ancillary metering service costs should be excluded from base opex as a negative step change to accurately determine Endeavour Energy's future metering operating expenditure allowance. We have not quantified the amount of this negative step change in our draft decision, but will apply it in our final decision."*[304]

Endeavour Energy can confirm that no reduction is required to the base opex for this reason. The revised metering services forecast opex excludes these costs from the base opex and these costs have been separately included in ancillary network services opex.

[304] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 44

8.2.4 Upfront Meter Prices

The AER rejected the upfront meter prices proposed by Endeavour Energy on the basis that they were above the lowest rates identified by the AER's consultant Marsden Jacob. Endeavour Energy has not revised its regulatory proposal to adopt the AER's alternative prices, however we have revised our prices to ensure they represent a comprehensive and accurate list of the available meters based on the latest available market information.

Endeavour Energy does not consider the AER draft decision reasonable as it adopts the lowest cost meter in each range provided by Marsden Jacob. In addition to this, the meter model is not specified. This means it is unlikely Endeavour Energy can achieve these prices as we have not been provided sufficient detail to know which meters should be procured. Furthermore, we have not been able to assess whether the meters prescribed by the AER's decision are of sufficient quality or reliability.

The acquisition of metering equipment is a long term decision with an asset life of 15 years. Achieving the lowest annualised cost for provision of the metering services requires a balance of capital and operating expenditure. The procurement of the lowest cost metering equipment will often require a greater level of operational expenditure to support early life failures and a greater failure rate over time. The higher cost metering equipment is often manufactured utilising better quality components and results in lower ongoing maintenance costs. Determining the optimal cost position requires an accurate forecast of future failure rates. This is often only possible once there has been a history of asset operation and failure established.

A further consideration in the selection of metering equipment is also the mounting hole pattern of the device. The preference is to procure metering equipment for use within maintenance programs that have a similar mounting pattern to existing installed devices, providing a lower and more efficient total replacement cost. For instance, our network contains asbestos meter boards. Maintenance activities that require drilling on an asbestos board requires specific procedures, resulting in increased time and associated costs. These costs need to be considered in determining the overall efficient costs of meter equipment.

We consider that an efficient annualised cost has been achieved for all new metering equipment through our metering equipment procurement strategy. The economies of scale proposed by the AER is not realistic considering the volume of meters procured in NSW each year. The comparison to Victorian bulk procurement arrangements is an irrelevant comparison considering the volume of meters procured is an order of magnitude different on a per annum basis (i.e. approximately 110,000 per year in NSW vs. one million procured meters per year in Victoria during the recent smart meter rollout).

Furthermore, in their report Marsden Jacob note that Endeavour Energy's interval meters prices are significantly above those of Essential and Ausgrid:

> *"As such Marsden Jacob recommends confirming the technical specifications of each of these meters and clarifying that the proposed costs refer only to the meter hardware costs (and do not include any labour installation or other contracted services). In the absence of further clarifying information we recommend meter hardware costs proposed by Endeavour Energy which exceed the applicable maximum benchmark rate be capped at the maximum recommended rates."*[305]

The AER has not sought to investigate the cause of this disparity as recommended by Marsden Jacob. Endeavour Energy notes that its metering population is primarily type 6 meters and as such we have not implemented the necessary systems and meter reading processes to accommodate type 5 meters on a large scale. The costs of this investment would be significant for the small population it would service, as such we utilise an alternative approach to read type 5 meters which utilises a modem and sim card until a critical volume of type 5 meters is achieved.

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[305] Marsden Jacob Associates, Advice prepared for the AER: Provision of advice in relation to Alternative Control Services – Final, 20 October 2014, page 17

Our upfront prices therefore include the cost of these components. If the AER does not provide for this solution then our metering capex and opex forecasts would require an upfront cost of approximately $0.6 million[306] to implement the necessary changes to our systems and processes and an increase in annual costs over the period of approximately $0.1 million.[307] Given this cost and the impact this would have on the small type 5 population, we consider our proposed approach more practical and efficient.

Ultimately, the re-classification of metering is designed to facilitate customer choice and a movement towards competition. We consider customers should be provided a full range of meter models to select from when making their decision. Whilst it is reasonable to provide customers the lowest cost option available, customers who value quality, lower annual costs or have other priorities should be afforded choice. Provided that the prices set by the AER are cost reflective this decision should be left with the customer. As such, we have revised our price list to provide a full suite of updated upfront metering prices at the lowest available lifecycle costs. These are contained in the table below and Attachment 8.04 to this proposal.

Table 8.6: Revised upfront metering prices

Upfront fee (($2014-15))	Type	Interval (3G modem)	TOU (interval without modem)	Accumulation
Whole Current Single Element Meter	Single phase[308]	$650.55	$85.98	$40.82
	Single phase import/export	$650.55	$85.98	$85.98
	Poly phase	$462.95	$266.13	$110.42
	Poly Phase import/export	$462.95	$266.13	$112.14
Current Transformer Meter	Poly phase	$560.30	$363.48	$363.48
	Poly Phase import/export	$560.30	$363.48	$363.48
Whole Current Dual Element Meter	Single phase	$741.60	$177.04	$177.04
	Single phase import/export	$741.60	$177.04	$177.04

8.2.5 Pricing Approach

In addition to rejecting our proposed annual prices and upfront meter costs the AER rejected an aspect of our pricing approach. Specifically, the AER state:

> *"we do not consider that this accelerated depreciation is efficient. It is unlikely that all meters will be provided by alternative service provides within 5 years. At that time, under Endeavour Energy's proposal, all existing and replacement meters will be fully depreciated but still providing services.*

[306] This would cover the cost of an upgrade to our MVRS, procurement of new handheld units, cradles, charging units, accessories and probes for handheld units.

[307] This would cover the cost of additional meter reading, special/non-routine read visits and increased maintenance.

[308] The single phase interval (3G modem) meter is more expensive than the poly phase meter as the single phase model requires an external modem as it does not have the capability of powering an internal 3G modem.

This is not an efficient long term outcome. We consider that the metering asset lives should continue to reflect the technical lives of the meters.

Accordingly, we have changed the remaining asset life for Endeavour Energy's existing metering assets as at 1 July 2014 to 23 years to allow a consistent roll forward of the life from the value approved for 1 July 2009 at the 2009 determination. We have also amended the standard asset life for replacement meters to 15 years."[309]

Endeavour Energy has not revised its proposed approach as we do not consider the AER's approach is in the best interests of customers. Given the relatively small size of our existing asset base it can be depreciated over an accelerated period of time without a material impact on prices and therefore customers. We do not consider it is inefficient for fully depreciated assets to be providing a service. In light of the AEMC rule change process it is unlikely this will eventuate or occur on a large scale. Rather, our approach ensures we are in a position to facilitate competition and ensure there are not long standing impediments to competition such as exit fees.

The AER's proposed approach will increase the stranded asset risk or create greater price volatility in the necessary pricing adjustments as customers exit. As we approach competition we consider the most prudent approach would be to not increase the size of the existing asset base and move towards a cost to serve pricing approach.

In addition to this, the AER accepted our proposed approach of a single metering fee for new and existing customers. However, the AER outlined their preference for a different set of prices. We have not revised our proposal as it would be costly and impractical to implement this approach in the time available. As noted above, the impact of our existing asset base on our annual price is low (approximately $3.60 per annum) and given the proximity of competition we do not wish to implement a costly solution. Hence, we have not departed from our simple approach that the AER have accepted.

It should also be noted that the AER did not accept Endeavour Energy's opening metering asset base of $22.7 million ($2013-14). However, the amount was not amended as the change represented an immaterial amount. Endeavour Energy has revised its standard control services RFM to give effect to the AER's decision. We have revised the opening metering asset base to reflect the 2013-14 actuals being incorporated into the roll forward model. This reduces the opening metering RAB to $18.8 million ($ nominal) compared to the original forecast above.

8.2.6 Control Mechanism

The AER draft decision is to apply a price cap as the form of control for metering services in accordance with the Stage 1 F&A. The charge will be set for the first year, with the following year's charges adjusted for CPI and an X-factor. Endeavour Energy note that the AER has not allowed for an X-factor adjustment in outer years as the X-factor has been set to zero.

Endeavour Energy notes that an X-factor has been allowed in the draft decision for ANS fees to allow for the AER's draft decision on real labour escalators. As such, Endeavour Energy do not understand why the X-factor has been disallowed for metering.

Endeavour Energy does not accept the removal of the X-factor as provided for in the AER draft decision. Labour escalation factors should apply in addition to the CPI increase for metering services to ensure that the charges continue to be cost reflective.

[309] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, pages 44-45

8.3. Ancillary Network Services

Endeavour Energy proposed cost reflective prices for each ancillary service as required by the AER. These services included new services identified by the AER's F&A process and re-classified services (from standard control) formerly known as 'Miscellaneous and Monopoly' fees as defined in the AER's F&A. The re-classified services had been set historically by Independent Pricing and Regulatory Tribunal of NSW, typically at cost and carried forward over the past regulatory periods. The prices proposed by Endeavour Energy for the 2014-19 period were intended to eliminate the cross-subsidisation of these specific activities by standard control services customers.

During the F&A consultation process Endeavour Energy expressed concerns with the AER's proposed approach. Whilst a cross-subsidy existed, we were of the view that an immediate transition to the new classification would represent a significant impact to ANS customers. Specifically:

> *"…our preliminary position is that all miscellaneous and monopoly services should be classified as standard control services. Moving to alternate control and developing cost reflective prices may expose customers and ASPs to price shocks and expose DNSPs to revenue shortfalls. The current regulated rates only allow the recovery of the marginal costs of providing the services, and the balance of the costs are paid by all customers through DUoS prices."*[310]

and

> *"The NSW DNSPs flagged in their responses to the Consultation Paper that the current regulated schedule of fees and rates is not cost-reflective and that the potential price increases required to ensure cost reflectivity are likely to cause customer satisfaction issues. There are also likely to be discrepancies in pricing across the three NSW DNSPs given the different characteristics of the networks."*[311]

Furthermore, in discussions with AER staff at the time, it was noted by Endeavour Energy (without having conducted a cost review) that there was an expectation that the immediate move to unbundled cost reflective pricing would lead to price movements in the order of hundreds of percent for some services. This was due in large part to the approach to pricing adopted by regulators that constrained the pricing of ANS to CPI for over a decade, despite known real cost movements occurring over that time that were inherently reallocated by those decisions into the general network charges.

Despite this the services were re-classified and thus we submitted cost-reflective prices that represented the efficient cost to provide this service. No alternative options were provided to Endeavour Energy to transition customers to the new prices. In giving effect to the F&A there will be instances of large increases such as the meter test fee, equally there are instances of significant decreases such as the site establishment fee.

AER Draft Determination

The AER's draft decision rejected our proposed prices in the draft determination:

> *"Our draft decision is to not approve some elements of Endeavour Energy's proposed fees for ancillary network services, public lighting and metering. We did not approve the proposed fees because they were considered to exceed the efficient cost of providing the services."*[312]

However, in reviewing other parts of the draft decision it appears the AER has accepted our proposed prices (see page 61 of AER's Overview). We presume the above statement is reflective of the AER's decision and this specific instance of an "acceptance" was simply an error.

[310] Endeavour Energy letter to AER; Classification of electricity distribution services in the ACT and NSW, 15 February 2012, page 5

[311] NSW DNSPs' Response to the AER's Preliminary F&A paper, 17 August 2012, page 31

[312] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, page 60

The AER's draft decision to reject was based on consultant advice provided by Marsden Jacobs which suggested our overheads and labour rates were inefficient:

> *"We consider the proposed fees are higher than fees based on maximum benchmark labour rates and overhead which we consider more appropriately reflect efficient costs."[313]*

Endeavour Energy has not revised the ANS prices we proposed to the AER to adopt the AER's labour and overhead benchmarks. We do not consider revisions are required to address the matters raised by the AER in its draft decision. Specifically:

- our labour rates are substantiated by actual information and we consider they represent a cost-reflective and efficient price;
- our overheads were calculated and applied in accordance with the AER's approved CAM; and
- there are examples of unreasonable outcomes in the AER's decision.

These issues are discussed in further detail in the following sections.

We have revised our proposed prices to reflect new labour escalators consistent with the revised standard control services forecast and an updated overhead factor based on the outcomes of the AER approved CAM. These revised prices are contained in Attachment 8.06 to this proposal.

Labour costs

As discussed above, the AER have made significant reductions to our proposed ANS fees utilising benchmarking analysis from Marsden Jacobs. Whilst we acknowledge benchmarking is an available assessment tool we consider it is of limited value in forecasting practical and efficient service delivery. Marsden Jacobs analysis suggests Endeavour Energy is above the maximum allowable benchmark labour rates. However, utilising RIN data suggests that Endeavour Energy represents the median labour cost per employee amongst the Australian DNSPs.

This is not to suggest that the benchmarks are accurate and reliable, rather this merely demonstrates the spectrum of results benchmarking can produce. We do not consider the techniques are sufficiently refined to be relied upon to such a degree. This application of the Marsden Jacobs analysis also ignores the fact that Endeavour Energy cannot access a national or international labour market. It is not clear if the results are driven by lower labour rates in other states, countries or industries. As such, Endeavour Energy contests that it cannot obtain the rates as described in the Marsden Jacob analysis based on the local labour rates for the qualifications required by each Ancillary Network Service.

It is inappropriate to utilise benchmarking in a deterministic manner for revenue and price setting. Instead, the benchmarking results should be used to guide a more detailed assessment of our proposed prices. In regards to this, the AER state that:

> *"The methodologies proposed by Endeavour Energy did not identify which type of labour performs each service, or the time taken to perform the service. We consider these to be key inputs in developing fees for ancillary network services."[314]*

We do not accept this observation and note that both the time taken and labour cost were provided to the AER to enable a more detailed assessment in our proposal. Specifically, we provided as part of our initial proposal, 36 fee methodology attachments, for each ANS service, which provided a significant level of detail on each fee and its various components. Additionally, we provided separate analysis post the submission of our proposal which mapped the fees to labour types requested by the AER. We consider both our time and labour rate inputs represent realistic and efficient costs of providing these services.

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[313] AER, Draft Decision Endeavour Energy distribution determination 2014-19 Attachment 16: Alternative Control Services, November 2014, page 13

[314] AER, Draft Decision Endeavour Energy distribution determination 2014-19 Attachment 16: Alternative Control Services, November 2014, page 18

Overhead costs

The overhead factor we applied in developing our prices was derived by applying the AER approved CAM. In rejecting our proposed prices the AER noted our overheads were above the maximum benchmark allowable. Specifically, Marsden Jacob stated:

> *"Marsden Jacob recommends that the average overhead applied for Ancillary Network Services be capped at 65%.*
>
> *… Importantly, we note that the methodology for allocating overheads is provided in the AER's Cost Allocation Methodology. Therefore, while our benchmarking considers the overheads for Ancillary Network Services in isolation, capping the overhead rate `may have unintended consequences for the broader Cost Allocation Methodology. The appropriate method of addressing the overhead allocation should be tested with the AER staff responsible for developing and enforcing the Cost Allocation Methodology. On this basis, this recommendation should be considered preliminary until confirmed with the relevant AER staff."*[315]

We consider the AER has applied the overhead cap provided by Marsden Jacob without considering the recommendation in full. As Marsden Jacob correctly identify, capping an overhead rate does have consequences for the CAM and our standard control service opex forecast. The overhead percentage allocated to a service is an output of applying the approved CAM and should not be utilised as an input. To cap the overhead and not provide for the recovery elsewhere is to effectively "strand" overheads and not permit the recovery of efficient costs. The AER should demonstrate how this approach is consistent with the CAM.

This draft determination simply adopts the cap proposed by Marsden Jacobs. This may indicate that the AER do not agree with its own approval of our cost allocation approach or consider our overheads inefficient (to the degree of 40%). If the AER considers our overheads are inefficient then this should be articulated by reference to the specific components of the overheads. In respect of this, we note that Table A.13 of the AER's draft decision on opex states that both our corporate and network overheads are 'comparable' to other DNSPs, meaning there is not a distinct "gap" in performance. As such, we do not consider a 40% reduction to the overhead rate applied to ANS is appropriate or justified.

Unreasonable outcomes

Endeavour Energy note the AER has a range of assessment techniques available in making a determination. This is particularly the case for alternative control services where the AER are not bound by the 'building block' approach. As such, we consider it would be prudent to utilise a number of techniques in forming a view and not to rely heavily on a single measure. This is of particular importance when there are substantive differences between the amount Endeavour Energy and the AER consider to be efficient.

In developing alternate prices the AER has relied almost exclusively on the advice provided by Marsden Jacobs. Given the limitations of benchmarking, or any single approach, unreasonable outcomes can be produced without validating the results. Outside of the issues raised in the above sections, we consider the following elements of the AER's draft decision unreasonable:

- Disconnections (meter box) – This fee has been reduced in the draft determination not only based on the labour rate, as discussed previously, but also by an unknown factor for which there appears to be no justification. The AER's fee of $63.94 is below that for a site visit of $69.29. This is illogical as visiting the site and performing the work would take a greater amount of time than simply visiting the site. The prescribed fee would be insufficient to recover our costs for disconnections alone and even more so when considering we conduct a substantive amount more reconnections than disconnections. Furthermore, the AER's workings suggest the fee is $66.90 rather than $63.94 as included in the draft decision.

[315] Marsden Jacob Associates, Advice prepared for the AER: Provision of advice in relation to Alternative Control Services – Final, 20 October 2014, page 5

In addition to this, it appears Retailers were supportive of a separate charge:

"AGL submitted that in South Australia, Queensland, and Victoria there are separate de-energisation and re-energisation fees. This provides greater transparency for customers and retailers. AGL also comments that separating fees makes additional services available. To ensure that customers moving into a property that was disconnected are not disadvantaged, a general move-in fee is charged. This covers the cost of a move-in read, plus any re-energisation work."[316]

Whilst we maintain our initial proposal we are not opposed to levying a separate fee for these services. The AER appear to have misinterpreted our position:

"Endeavour Energy further submits that the payment can cover multiple customers but this is very rare in their experience. This may occur if the disconnection occurs for one customer, but a different customer moves in and needs the power put back on. Endeavour Energy generally avoids this occurrence as it does not typically disconnect a customer on a move-out/final read. Endeavour Energy only tends to disconnect where a customer has not paid their bills or for those sites where access has proven difficult and the retailer requests physical de-energisation. Whilst Endeavour Energy does not specifically track this event, at a high level Endeavour Energy estimates that it would be less than one per cent of cases where there is disconnection for one customer and another customer moves in to take over the site."[317]

To be clear, we did not suggest that we typically provide a single disconnection visit rather than a disconnection and following reconnection as defined in the service offering in the proposal. We were merely noting that a separate fee may disadvantage a customer reconnecting following the disconnection of a different customer (e.g. for non-payment). As the occurrence of this is rare we considered it did not prohibit the AER establishing a separate fee. If the AER were to adopt this position we estimate the reconnection and disconnection fees would equate to approximately $80. Should the AER wish to consult further on this matter we can provide a more detailed fee estimate.

- Reconnection/Disconnection (Meter Load Tail) – a lower labour rate of $127.87 is used rather than the AER's benchmark R4 labour rate of $133.80 without justification.
- Reconnection/Disconnection (Pole Top/Pillar Box – Site visit) – the AER's workings suggest this fee is $167.39 rather than $144.74 in its draft decision table of prices.
- Network tariff change request – the AER rejected this fee based on a definitional issue. In response to the AER's draft decision we have revised our definition for this service so that the fee will only apply to a valid network tariff change request outside of the annual pricing process. Whilst this reduces the volume in our pricing calculation we have not sought to increase the fee originally proposed.
- Access (standby Person), Authorisations, Connection offer service, Customer interface co-ordination and Recovery of debt collection costs - these fees all provide examples of an inconsistent application of benchmarking. For these fees the AER has used a mixture of benchmark labour or overhead rates with Endeavour Energy's labour or overhead rates where these are lower than the AER's respective benchmark. This cherry-picking of benchmarking combines labour and overhead rates that are incompatible (as they are calculated on a different basis) and is unreasonable. If the AER considers the benchmark rates are more reliable and efficient (to be clear we do not) these should be universally applied rather than selectively applied only to reduce fees.
- Access permits – in the AER's calculation it appears the AER has switched the rates for district operators and system operators. This is either in error or without justification and it reduces the AER's alternate fee to $2,108.48 rather than $2,377.81.
- Clearance to work – we cannot verify this alternate fee as the calculation was not provided. It appears the AER has applied the same fee it developed for access permit. This requires confirmation.

[316] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 25

[317] AER, Draft Decision Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 16: Alternative control services, November 2014, page 25

- Franchise CT Meter Install – the AER's alternate fee is based on an R1 (administrative) benchmark labour rate rather than the benchmark R2 or R4 labour rate. This work cannot be performed by an R1 and no explanation is provided as to why this approach is reasonable.

It is for these reasons and those outlined above that Endeavour Energy has not revised the proposed ANS prices to adopt the AER's benchmark approach. Rather, as outlined above we have revised our prices to reflect the latest available information to ensure they continue to represent a cost-reflective and efficient outcome. The revised fees are provided as Attachment 8.06 to this proposal.

Site establishment fee

In addition to this we also note that we did not submit in our proposal that a site establishment fee will be levied against the ASP. Whilst that is currently the method of charging, we are currently considering whether this approach should change. Currently, ASPs charge the customer a site establishment fee when levied against the ASP. In the past, retailers could not be charged this fee as in some cases it was the local retailer who defaulted as the retailer for new installations. This occurred where a retailer was not nominated at the application stage but may not have necessarily been the retailer once the customer moved into the premise.

Due to an MSATS system change in May 2014 where National Meter Identifiers (NMI) could not be published to MSATS until approval was gained by the retailer, then Endeavour Energy propose that as the retailer must submit an 'Allocate NMI B2B service order', the site establishment fee should be levied against the retailer subject to Endeavour Energy's business processes. We will consider this change further and consult with stakeholders before making any final decision.

9 PRICING ARRANGEMENTS AND NEGOTIATED FRAMEWORK

Summary

The AER has made significant amendments to our proposed pricing arrangements. Where the AER has not accepted our proposal, we have set out our written submissions on why the AER should accept our revised proposal. The AER has however, accepted our proposed negotiating framework.

The purpose of this chapter is to respond to the AER's draft decisions on:

1. The implementation of the Control Mechanism for Standard Control Services (including related recovery matters and customer assignment procedures) set out in AER draft decision Attachment 14; and
2. Endeavour Energy's Negotiating Framework set out in AER draft decision Attachment 17.

The AER has broadly endorsed Endeavour Energy's proposed approach to the above matters. In the sections below we provide our response to some of the detailed implications of the AER's proposed approach to the control mechanism for standard control services; we have revised our proposed procedures for Assigning and Reassigning Customers to Tariff classes in some minor respects to address issues raised in the AER's decision; but we have maintained our position on all key areas including the appropriateness of providing notice to retailers of proposed tariffs assignments rather than directly to customer. The AER has accepted Endeavour Energy's Negotiating Framework and we have noted the AER draft decision on the negotiated distribution service criteria but suggest that the language be modified to reflect a principle and criteria approach under the Rules rather than mandatory requirements.

9.1. Application and demonstration of compliance with control mechanism and side constraint mechanism for standard control distribution services

This section provides Endeavour Energy's response to the AER's draft decision on the control mechanism for Standard Control Services.

Broadly Endeavour Energy agrees that the approach put forward in the AER's draft determination with respect to the application of the control mechanism is appropriate. However, we have some concerns with certain aspects of the proposed formulas to implement the control mechanisms, (which may be unintended transposition errors).

To assist understanding and ease of reference Endeavour Energy has set out each of the elements of the decision and a brief indication of its response in Table 9.1 below. Endeavour Energy's more detailed response is set out in Attachment 9.01.

9 PRICING ARRANGEMENTS AND NEGOTIATED FRAMEWORK

Table 9.1: Overview of Endeavour Energy's response to the AER's Draft Decision on Control Mechanism for Standard Control Services

AER Decision	Endeavour Energy Response	Brief Description of Response
Revenue Cap Control Mechanism for Standard Control Services is revenue cap.	Accept as Rules require that Control Mechanism be the same as that specified in the AER's Framework and Approach paper.	
Application of Revenue Cap. Revenue cap comprised of Annual Revenue Requirement (ARR) for standard control services calculated in accordance with revenue cap formulas in Figures 14-1.	In principle accept formula, but will seek further consideration of some elements of the formula.	Endeavour Energy request that the determination expressly provide that the "Price" component for year t in the Revenue Cap Formula includes the unders and overs adjustment.
Side Constraints Side Constraints apply to price movements for each tariff class must be consistent with formula in Figure 14-2.	Endeavour Energy disagrees with the formula in Figure 14-2 on the grounds that it is inconsistent with 6.18.6(c) of the Rules which requires the side constraint be the greater of the CPI-X limitation on any increase in the DNSP's expected weighted average revenue between the two regulatory years plus 2% or CPI plus 2%. Endeavour Energy has proposed an alternative formula that addresses our concerns and corrects for this error in the formula in Figure 14-2.	Endeavour Energy objects to the formula and proposes that the permissible percentage in the formula be expressed as the greater of a CPI-X plus 2% or CPI plus 2%. Endeavour Energy also notes that there is an unintended error in formula in Figure 14-2 where the AER has expressed the price change as being both less than or equal to (≤) and equal to (=).
DUOS Unders and Overs Accounts Endeavour Energy must demonstrate compliance with the control mechanism for standard control services in accordance with Appendix A, of the AER's draft decision.	Endeavour Energy disagrees with aspects of Appendix A which addresses the DUOS unders and overs account.	Endeavour Energy objects to the AER's draft decision not to apply interest to the opening balance and the under/over recovery balance for the regulatory year in year "t"
"TUOS" Under/Over Recovery Endeavour Energy must submit as part of its annual pricing proposal, a record of the amount of revenue recovered from TUOS charges and associated payments in accordance with Appendix B, of the AER's draft decision.	Appendix B addresses Transmission Use of System "TUOS" unders and overs account but should address "Designated Pricing Proposal Charges Unders and Overs Account.	Endeavour Energy objects to the AER's draft decision not to apply interest to the opening balance and the under/over recovery balance for the regulatory year in year "t"
Jurisdictional Schemes Reporting Endeavour Energy must report to the AER its jurisdiction scheme amounts recovered in accordance with Appendices C, of the AER's draft decision.	The AER has accepted Endeavour Energy's proposed approach, except in respect to the inclusion of interest in year t.	Endeavour Energy objects to the AER's draft decision not to apply interest to the opening balance and the under/over recovery balance for the regulatory year in year "t"
Application of Tolerance Limit	Endeavour Energy disagrees with the AER's approach to tolerance limits	Endeavour Energy seeks reconsideration of the AER's rejection of our proposed approach to tolerance, particularly in respect to imposing a limit on the recoupment of residual metering asset costs.

9.2. Procedures for Assigning Customers to tariff classes

This section responds to the AER's draft decision set in section D of Attachment 14 to the draft decision. The AER rejected Endeavour Energy's proposed procedures for assigning customers to tariff classes on the false assumption that Endeavour Energy's proposed methodology will limit a retail customer's ability to seek recourse should they disagree with their tariff class assignment.

Endeavour Energy's disagrees with the AER's draft decision and notes the proposed tariff assignment methodology will have no impact on a retail customers ability to object, request further information or find other mediation methods should the retail customer disagree with a tariff assignment or reassignment.

Endeavour Energy notes that Part 4 of the National Electricity Retail Law (NERL) – Small Customer complaints and Dispute Resolution, defines a retail customer's right to dispute resolution. In accordance with the NERL, Endeavour Energy maintains on its website a set of procedures detailing our processes for handling customer complaints and disputes.[318] Endeavour Energy is bound by and complies with these NERL dispute resolution requirements.

Further, Endeavour Energy's customer connection agreements[319] specify our retail customer's right to dispute resolution.

The AER's claim that Endeavour Energy's proposed tariff assignment methodology will restrict our customer's ability to seek recourse in the event of a disagreement is not correct.

Endeavour Energy believes that the AER's draft decision is overly prescriptive, redundant and inconsistent with Endeavour Energy's requirements under the NERL.

Whilst Endeavour Energy has made minor revisions to address the AER's concerns we are concerned that the AER's proposed changes will be unduly restrictive and that the requirement to notify customers rather than their retailer is not consistent with the framework established under the NERL and will lead to unworkable timeframes for finalising pricing proposals should customers or retailers seek a review of Endeavour Energy's proposal.

Endeavour Energy's detailed response to the AER's draft decision on these procedures and our revised procedures are set out in in Attachment 9.02.

9.3. Endeavour Energy's Negotiating Framework and Negotiated Distribution Service Criteria

This section responds to the AER's draft decision set out in Attachment 17 - Negotiated distribution services framework and criteria.

The AER has accepted Endeavour Energy's Negotiating Framework without amendment and consequently Endeavour Energy makes no further submission or proposal in relation to our proposed framework.

[318] Endeavour Energy's published procedures for customer complaints, appeals and resolution can be found in Attachment 9.02.

[319] Endeavour Energy Deemed Standard Connection Contracts, Section 16 and Endeavour Energy Deemed Standard Connection Contract for Large Customers, Section 17.

ATTACHMENTS

ID #	Title
Chapter 1 – About this proposal	
1.01	Confidentiality Claim template
1.02	Huegin: Response to draft decision on behalf of Networks NSW and ActewAGL - Technical response to the application of benchmarking by the AER
1.03	Frontier Economics: Review of AER's econometric models and their application in the draft determination for Networks NSW
1.04	Advisian: Review of AER's benchmarking
1.05	PWC: Independent expert advice on appropriateness of RIN data for benchmarking comparisons
1.06	David Newberry (Cambridge Economic Policy Associates): Expert report
1.07	Pacific Economic Group, LLC: Statistical Benchmarking for NSW Distributors
1.08	COO Statement (Chief Operating Officer, Endeavour Energy)
1.09	R2A: Asset/System Failure – Safety Due Diligence Review
1.10	AON: Insurance Advice Report - Insurance costs and coverage impacts arising from cuts in vegetation management expenditure for the 2014-2019 regulatory period (CONFIDENTIAL)
1.11	Commissioner - Fire and Rescue NSW: Letter to CEO of Networks NSW
1.12	Commissioner - NSW Rural Fire Service: Letter to CEO of Networks NSW
1.13	Jacobs: System capex and maintenance prudency assessment
1.14	Jacobs: Reliability Impact Assessment
1.15	Standard and Poor's: Confidential Credit Assessment – Endeavour Energy stand-alone credit profile (CONFIDENTIAL)
1.16	UBS: Response to the Networks NSW request for financeability analysis following the AER draft decision of November 2014 (CONFIDENTIAL)
1.17	NNSW Business transformation
1.18	CEO of NSW Roads and Maritime Services: Letter to CEO of Networks NSW
Chapter 2 – Our Customers	
2.01	Customer Engagement Plan 2014-19 draft
2.02	Customer and stakeholder engagement
2.03	IPSOS: Customer research – Willingness to pay for network services
2.04	Your Power Your Say Facebook Activity Report - November 2013 to October 2014
2.05	Media Release: More households benefitting from energy rebates
2.06	Consumer Engagement Forum Outcomes report

ATTACHMENTS

ID #	Title
Chapter 4 – Building block proposal	
4.01	Updated - PTRM (CONFIDENTIAL)
4.02	Updated – RFM
4.03	Advisian: Review of standard and remaining lives of assets
4.04	Ernst and Young: Accounting for Provisions - Assessing the AER's Approach
Chapter 5 – Capital expenditure	
5.01	Ernst and Young: Analysis of AER draft decision on capex
5.02	Response to AER decision on Augex
5.03	Response to AER decision on Repex
5.04	Response to AER decision on Reliability and STPIS
5.05	Investigation reports for reliability projects
5.06	Business cases for SCADA and Network Control Protection
5.07	Advisian: Networks NSW Independent review of the risk based prioritisation process for Networks NSW - post implementation review
5.08	Cost Escalation updates
5.09	Statement of John Hardwick, Group Executive - Network Strategy
Chapter 6 – Operating expenditure	
6.01	Response to AER on efficiency of labour practices
6.02	CEG: Labour Unit Cost - Review of Deloitte Report (CONFIDENTIAL)
6.03	K&L Gates: Comparison and Analysis of Enterprise Bargaining Agreements for Distribution Networks (CONFIDENTIAL)
6.04	Response to AER on vegetation management
Chapter 7 – Weighted average cost of capital	
7.01	CEG: Efficient debt financing costs
7.02	Frontier Economics: Cost of debt transition for the NSW DNSPs
7.03	CEG: Estimating the cost of equity
7.04	SFG: Report on the cost of equity for ActewAGL and the NSW DNSPs
7.05	Bruce Grundy: Letter from Bruce Grundy to Justin De Lorenzo - 9 January 2015
7.06	NERA: Memo on Revised MRP estimates to 2013
7.07	Endeavour Energy's revised proposal on gamma
7.08	AOFM: Letter from Michael Bath to Steve Knight re: domestic interest rate swaps
7.09	Statement of Justin DeLorenzo, Chief Financial Officer, Networks NSW

ATTACHMENTS

ID #	Title
Chapter 8 – Alternative Control Services	
8.01	Revised model and prices for Public Lighting
8.02	Specifications of LED (confidential)
8.03	Bulk lamp replacement cycles (confidential)
8.04	Revised metering model and prices
8.05	Fee Methodology for ancillary network services
8.06	Revised ancillary network services price list
Chapter 9 – Pricing Arrangements and negotiated framework	
9.01	Endeavour Energy: Application and Demonstration of compliance with control mechanism for standard control services
9.02	Proposed Procedure for Assigning or Re-Assignment of Retail Customers to Tariff Classes

GLOSSARY

Term	Definition
2014-19 period	The period that comprises both the transitional regulatory control period 1 July 2014 to 30 June 2015 and the regulatory period 1 July 2015 to 30 June 2019 (2015-19 regulatory control period).
2015-19 regulatory period	The regulatory period commencing 1 July 2015 to 30 June 2019.
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Augex	Augmentation expenditure model
CAM	Cost allocation method
CAPEX	Capital expenditure
CAPM	Capital asset pricing model
CESS	Capital Expenditure Sharing Scheme
CCP	Consumer Challenge Panel
CPI	Consumer Price Index
DGM	Dividend Growth Model
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution network service provider
DRP	Debt Risk Premium
DUOS	Distribution Use of System
EBSS	Efficiency benefit sharing scheme
EI	Economic Insights
F&A	Framework and approach
FFM	Fama-French 3 Factor Model
FMECA/RCM	Failure Mode Effect & Criticality Analysis/Reliability Centred Maintenance
GFC	Global financial crisis
HV	High voltage
Last regulatory period	Regulatory control period of 1 July 2004 to 30 June 2009
LiDAR	Laser Imaging Detection and Ranging (System)
LV	Low voltage
MRP	Market Risk Premium
NECF	National Energy Customer Framework
NEL	National Electricity Law

GLOSSARY

Term	Definition
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
Next five years	The five year period between 1 July 2014 to 30 June 2019
Next regulatory period	Regulatory period of 1 July 2015 to 30 June 2019
NMI	National Metering Identifier
OPEX	Operating Expenditure
PCBU	Persons Conducting Business Undertaking
PTRM	Post tax revenue model
RAB	Regulatory asset base
Regulatory Proposal	Endeavour Energy's proposal for the next regulatory period submitted under clause 6.8 of the Rules
Repex	Replacement expenditure model
Revised proposal	Endeavour Energy's revised regulatory proposal for period of 1 July 2015 to 30 June 2019 (including 2014-15 information)
Rules	National Electricity Rules
Initial proposal	Endeavour Energy's May 2014 regulatory submission documents and supporting attachments
STPIS	Service Target Performance Incentive Scheme
Transitional Rules	Division 2 of Chapter 11 transitional provisions for NSW/ACT distribution network service providers for the economic regulation of NSW distribution services for the transitional regulatory control period 1 July 2014 to 30 June 2015
Transitional year	Regulatory control period of 1 July 2014 to 30 June 2015
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WPD	Western Power Distribution