REVISED REGULATORY PROPOSAL

> 1 July 2014 to 30 June 2019

> Submission date: 20 January 2015

CONTENTS

EXECUTIVE SUMMARY

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

Since the AER's determination in 2009, Essential 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 customers.

Improvements in capital and operating efficiencies of $634 million already delivered by Essential 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 30 June 2019. Our priorities continue to align with the long term interests of customers to achieve 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 safely deliver the NSW Government's mandated customer reliability levels, including average customer supply availability of 99.94 per cent for regional and rural customers.

> Real reductions in forecast average distribution network charges for customers of 9.1 per cent by the end of the 2014-19 regulatory period.

> Forecast capital and operating programs that are $1.8 billion (43 per cent) and $28.4 million (1 per cent) less, respectively, in real terms than the AER approved forecast amounts for capital and operating programs in the 2009-14 regulatory period.

> Forecast annualised labour productivity improvements of 22.6 per cent 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.

A pathway to improved capital and operating efficiency

Essential 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, decreasing network reliability and unsustainable network funding are not in the long term interest of customers and are in conflict with the NEO.

Essential Energy and the AER also share an objective to improve the capital and operating efficiency of our NSW public owned electricity distribution network. While that journey is well underway, further improvement is required in the interests of NSW families and businesses. This revised proposal submitted by Essential Energy provides a pathway for 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 proposal are outlined below.

Capital expenditure (Chapter 6)

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

> Forecast capital expenditure for standard control services that is 43 per cent lower than the amount approved by the AER for 2009-14.

> 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 Essential Energy's revised and risk assessed capital program.

> An increase in forecast capital expenditure on low mains to reflect the introduction of LiDAR technology that has identified non-compliant clearance levels.

Figure E-1 sets out the capital expenditure in Essential Energy's initial proposal, the AER's draft determination, Essential Energy's revised proposal and, for comparative purposes, the forecast capital expenditure program that the AER approved in respect of the 2009-14 regulatory period ($2013-14).

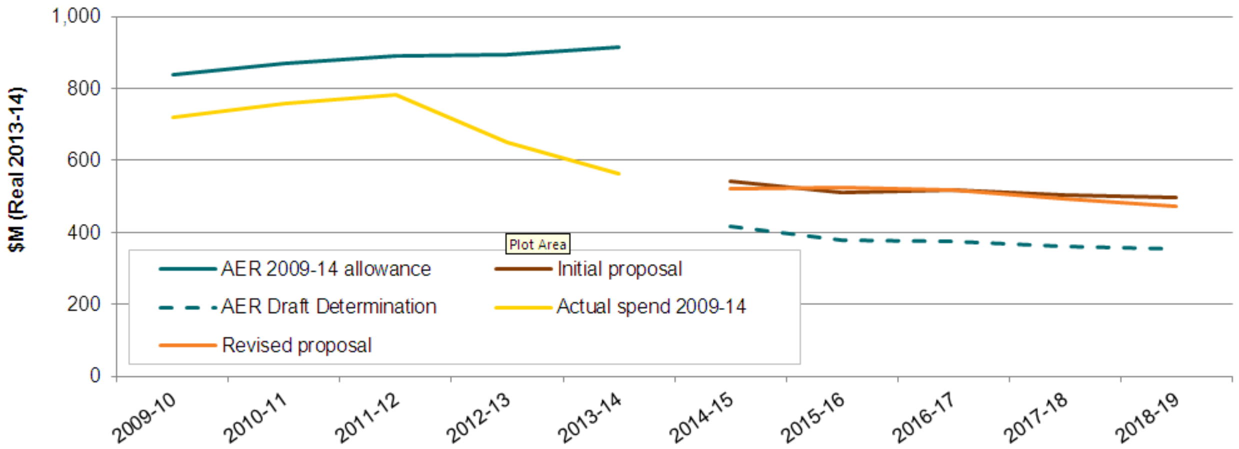

Figure E-1: Capital expenditure – AER allowances, Actual / Proposed

As illustrated above, the forecast capital expenditure amounts contained in this revised proposal are 43 per cent less ($2013-14) than the forecast capital expenditure amounts that the AER approved in respect of the 2009-14 regulatory period and one per cent less than Essential Energy's initial proposal.

Operating expenditure (Chapter 7)

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

> Forecast progressive improvements in labour productivity which grow to 22.6 per cent by the end of the 2014-19 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 management costs to reflect the additional volume of work from the introduction of LiDAR technology.

> An increase in forecast network maintenance costs to rectify network defects identified through LiDAR technology.

> An increase in forecast operating expenditure for low mains to reflect the introduction of LiDAR technology that has identified non-compliant clearance levels.

> 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 customers' 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 management contracts, have been escalated consistent with the terms of the contract. Fleet costs have been reduced proportionally with labour productivity improvements.

> Labour costs escalation consistent with the AER's approach in the draft determination.

Figure E-2 sets out the operating expenditure in Essential 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).

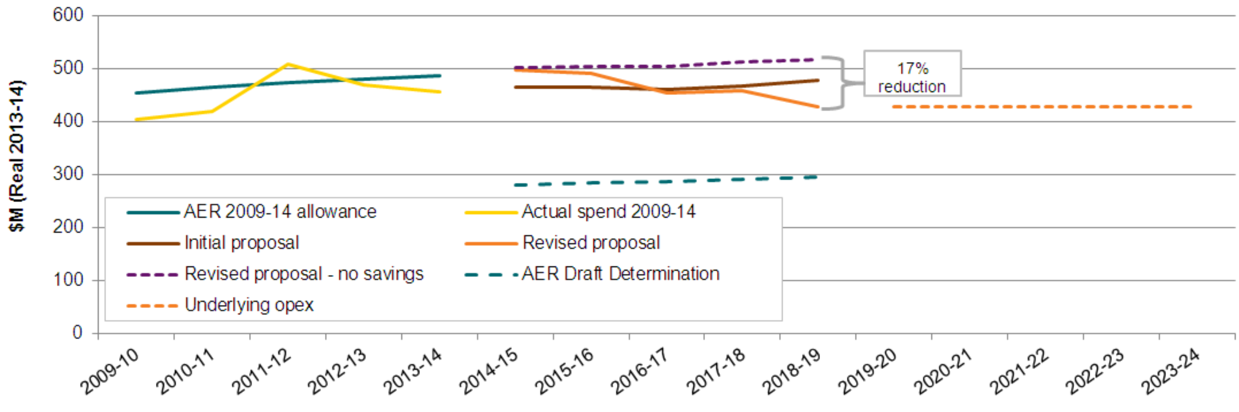

Figure E-2: Operating expenditure – AER allowances, Actual / Proposed

As illustrated above, the operating expenditures contained in this revised proposal represent a one per cent reduction ($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 marginal reduction compared to Essential Energy's initial proposal.

While there are significant and sustainable reductions in operating expenditure associated with labour productivity rates over the 2014-19 regulatory period, those benefits are moderated by the operating expenditure related to the rectification of non-compliant clearance levels, the addition of reallocated labour costs related to Essential's transformation from a period of high growth and the regulatory obligation to pay redundancy costs associated with driving improvements in labour productivity. As illustrated in Figure E-2, the long term interest of customers are advanced by a reduced operating program and lower operating costs in the medium to long term based on sustainable labour productivity improvement, effective vegetation management and a risk based bushfire mitigation program.

This is reflected by the "underlying operating expenditure" line in Figure E-2 that illustrates the lower 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 E-3 depicts Essential Energy's total expenditure (capital and operating) for the nominated periods. In real terms ($2013-14) our revised proposal is 28 per cent lower than the 2009-14 programs approved by the AER and marginally lower than was submitted in our initial proposal.

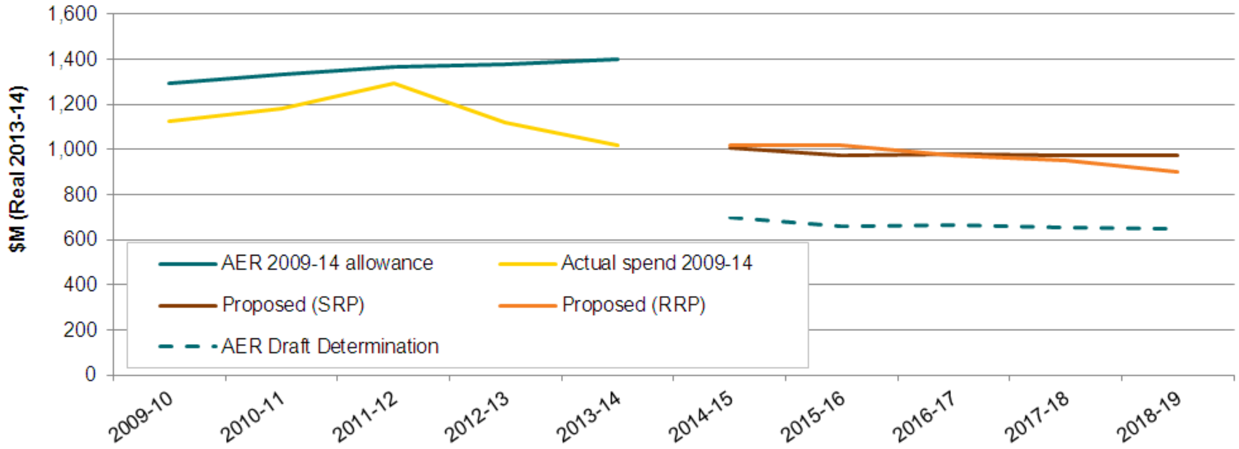

Figure E-3: Total expenditure – AER allowances, Actual / Proposed – 2009-19

Rate of return (Chapter 8)

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

In summary:

- We propose an allowed cost of debt of 7.98 per cent, which has been calculated consistent with the ten 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 Essential Energy has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's debt transition would significantly under compensate Essential 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 Essential 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 Essential Energy as:

    - 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 issue 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 per cent, 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 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).

Essential Energy's revised proposal contains a return on capital of 8.85 per cent that is consistent with the approach set out in our initial proposal updated for movements in various market parameters. Chapter 8 outlines our rationale for why the AER should not apply a transition to the cost of debt that recognises the individual circumstances of Essential Energy, and why the AER's return on equity has not adequately taken account of all relevant data.

Incentive mechanisms (Chapter 4)

Essential Energy considers that unless the AER accepts our revised capital and operating expenditure proposals, 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 operating expenditure and the likely incentives Essential 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 operating expenditure 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 operating expenditure is unachievable, and there would be a high risk of substantial penalties if an EBSS was applied. As we demonstrate in Chapter 7 of this revised proposal, the AER's responsibility is to set an efficient and prudent operating expenditure that meets the operating expenditure objectives. If the AER made such a decision, then an EBSS incentive would provide a symmetrical incentive.

> If the AER, however, decide to not accept our proposal and to substitute a lower 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 carryovers of efficiency gains and losses caused by movements in provisions in the draft decision for the 2015-19 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 movements in employee related provisions do represent actual costs incurred by Essential 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 Essential 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.

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 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 period in accordance with its published guidelines.

> Essential 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 its Stage 2 Framework & Approach (F&A) Paper. The AER's draft determination is consistent with the Stage 2 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 original proposal agreed with the AER applying a scheme from 2015-16 onwards, and set out a revenue at risk of 2.5 per cent. The AER's draft decision has applied a STPIS from 2015-16 onwards with a revenue at risk of 2.5 per cent consistent with our proposal and the Stage 2 F&A paper. The AER has also accepted our proposed revenue at risk for each parameter.

> However, the AER has not accepted our proposed design elements. Attachment 4.2 sets out why we have not revised our proposal for the following changes for reliability parameters. We do not agree with the AER's approach to set a target which is higher than our current performance, rather than to set reliability targets based on our average performance over the last five years based on an incorrect supposition that investment undertaken in 2009-14 regulatory period will have an impact on our targets in the 2014-19 regulatory 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 the reduction to our future capital and operating expenditure programs of 27 per cent and 38 per cent respectively (or of similar magnitude), 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 1.5). Modelling by Jacobs confirmed that in those circumstances reliability would materially worsen compared to previous forecasts, with further degradation in following regulatory periods.

> A STPIS incentive framework in the 2014-19 regulatory 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 accepts our revised capital and operating expenditure proposals, the STPIS should not apply.

Alternative Control Services (Chapter 9)

We have not accepted the AER's decisions on charges for public lighting, ancillary network services and annual metering services. As requested by the AER, we have provided additional information to demonstrate we will incur incremental administrative costs when a customer decides to switch to an alternate meter service provider that would appropriately be recovered through an administration fee. Further detail is provided in Chapter 9.

Essential Energy's annual revenue requirements (Chapter 5)

Table E-1 sets out the revised smoothed nominal annual revenue requirements for Essential Energy compared to the AER draft determination and Essential Energy's initial proposal.

Table E-1: Smoothed annual revenue requirements

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Initial proposal	1,353	1,352	1,348	1,347	1,357	6,757
AER draft determination	1,292	886	908	931	954	4,970
Revised proposal	1,292	1,333	1,366	1,400	1,447	6,837

As illustrated above, the smoothed nominal annual revenue requirements in this revised proposal are $80 million, or 1.2 per cent higher than those forecast in our initial proposal.

Critique of AER's draft determination

The AER's deterministic use of a flawed benchmarking model in its draft determination for Essential Energy has resulted in reductions to submitted operating expenditure of 38 per cent. Essential Energy's Chief Operating Officer has signed a statement (Attachment 1.1) 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 Essential Energy's 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 under investment by Essential Energy in both capital and operating expenditure, and would compromise the safety, the reliability and the ongoing sustainability of its network.*

In light of the AER's draft decision, Essential Energy has made a number of revisions to its initial proposal so as to incorporate the substance of changes required to address matters raised by the draft determination or the AER's reason for it. 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 the four reasons set out below.

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 Essential 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 on behalf of Essential Energy found that it is foreseeable that safety risks for Essential Energy workers and members of the public will increase from the AER's draft determination where it is proposed that Essential 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 Essential 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 Essential Energy's vegetation control program implied by the AER's 38 per cent aggregate reduction in operating expenditure. The Commissioners of NSW Fire and Rescue and the 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 Essential Energy's bushfire risk mitigation plan, as a result of adopting LiDAR technology. This adjustment was foreshadowed in Essential Energy's initial proposal.

2. AER approach to benchmarking is untested and unreliable (Chapters 1 and 7)

In the draft determination the AER made retrospective and significant reductions in operating expenditure driven by the deterministic use of the unreliable, untested and unsafe Economic Insights report dated 17 November 2014. The AER breached its obligations under the Rules 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 Essential Energy on how the AER would use the report to assess (and apparently determine) forecast operating expenditure. This is unsatisfactory, prejudicial to the interests of Essential Energy and inconsistent with the NER.

Further, the AER engaged Economic Insights to review whether Essential Energy's operating expenditure base year should be adjusted, and whether a productivity factor should be applied into the forecast period. Economic Insights did not contact Essential 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 Essential Energy's operating expenditure and at the same time Economic Insights relies heavily on the AER's draft 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 Rules framework. We consider that the AER misdirected itself in its pursuit of an econometric benchmarking model to produce an outcome (number) that it could use to derive operating expenditure 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 operating expenditure for each company. The AER did not, as in previous determinations undertake a detailed assessment of components of operating expenditure 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 operating expenditure 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 Essential Energy's regulatory and legally binding contractual obligations.

Essential Energy has commissioned expert reviews of the AER's approach, benchmarking model and conclusions. These reviews by Frontier Economics (Attachment 7.1), Huegin (Attachment 6.9), David Newbery (Attachment 1.6) Pacific Economics Group Research (Attachment 7.3), Advisian (Attachment 7.2) and PwC (Attachment 6.3) have provided compelling evidence that the AER's approach and conclusions are unsafe and unreliable.

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

The AER has discounted the substantial body of evidence gathered by Essential Energy to assess and test customer and stakeholder preferences.

These preferences form the basis of our five year proposal and are the result of Essential Energy's customer engagement strategy, designed well ahead of the publication of the AER's consumer engagement guideline in November 2013.

The strategy identified discrete customer cohorts and used multiple methods to gather, assess and record customers' preferences. It also used well-accepted engagement techniques, including quantitative and qualitative research, face to face deliberative planning workshops with residential and small business customers, 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.

Despite this body of evidence, the AER has largely rejected feedback collected from more than 1,000 Essential Energy customers and stakeholders, electing instead to rely on feedback provided in just 20 submissions relating to standard control services in our initial proposal. Further examination shows many claims in these submissions to be unsubstantiated, incorrect or inconsistent with engagement commissioned by Essential Energy before and after our initial proposal was lodged.

In November 2014 Essential Energy commissioned further research into customer preferences using a Discrete Choice Experiment – or choice modelling – to gain a better understanding of customers' willingness to pay for services. A report on the initial findings of this research is provided at Attachment 3.1.

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 charges 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 out of nine tested scenarios for Essential 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.*[1]

The choice modelling research revealed that while charges are 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, service restoration times and pole maintenance were also key drivers for Essential Energy.

These findings provide further insight into customer preferences, and reinforce the conclusions drawn from earlier engagement initiatives that were used to support our initial proposal.

Finally, the AER's notion of more "regulated blackouts" diminishes the serious responsibility Essential Energy has to do all that is "reasonably practical" for the wellbeing of more than 15,000 life support customers spread across our 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.

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 discretion in making those parts of a distribution determination relating to direct control network services. The revenue and pricing principles include the following:

[1] IPSOS Research, *Willingness to pay for network services,* January 2015, p24.

a) A regulated network provider should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services and complying with regulatory obligations, requirements or making a regulatory payment (NEL section 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 section 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 that price or charge relates (NEL section 7A(5)).

The ongoing uncertainty surrounding the deterministic use of benchmarking, the AER's unwillingness to consult with the industry on their 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) (Attachment 1.7) 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 Essential Energy commensurate with the revenue and pricing principles in the NEL include:

> **The return on capital** – Essential Energy’s debt management practices are efficient and are consistent with the ten year trailing average approach determined favoured 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 Essential Energy. The AER’s transition to the trailing average as outlined in the draft determinations result in a cost of debt that is insufficient to cover the debt servicing costs of Essential 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 Essential Energy's current 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 Essential 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 costs including vegetation management and fleet management.

> **Retrospective “true up”** – the “true up” arising from the AER's April 2014 "placeholder" transitional revenue determination for 2014-15 year is $338.9 million (26 per cent) in excess of the funding now proposed for the same year in the 27 November 2014 AER draft determination. 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 Essential 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 30 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 $689 million or 27 per cent reduction in the capital program compared to that proposed by Essential Energy and a $2,530 million or 57 per cent 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 Essential Energy’s Cost Allocation Methodology (CAM) approved by the AER. The accounting effect of the capital program proposed by the AER 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 asymmetrical bonus/penalty scheme and increased the regulatory and commercial risk of providing network services.

> **Transforming our business** - The AER has sought submissions in Essential 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. 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, that is, an allowance that it is satisfied reasonably reflects the capital and operating expenditure criteria and that is the amount which should be reflected in allowed revenues. 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 Australian Energy Market Commission's (AEMC's) 2012 Rule Change[2]. That rule change did not remove the requirement of the AER to consider the circumstances of a DNSP. The AER's obligation is to direct itself to the operating expenditure and capital expenditure criteria, which requires proper engagement with the DNSP's proposal and the circumstances set out in that proposal.
- As part of Essential Energy's commitment to improve operating and capital efficiency, we propose progressive and sustainable improvements in labour through progressive reductions in our workforce. As with the majority of electricity distributors operating in the NEM, Essential Energy's Fair Work Commission certified enterprise bargaining agreement provides for a payment scale for employees accepting redundancy. Providing funding for legally binding redundancy payments is in the long term interests of customers because operating costs are permanently reduced.
- The NEL contains revenue and pricing principles that bind the AER to provide a return to Essential 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 Economic Insights benchmark model to establish an "efficient frontier" for Essential Energy's aggregate operating expenditure and then determined the 2015-2019 expenditure based on that "efficient frontier". This approach removes the need for incentives to promote economic efficiency provided for in the NEL.

Financial sustainability (Chapter 1)

Essential Energy has engaged 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

[2] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012.

set out in this revised proposal and our forecast interest costs. The confidential S&P report, provided as Attachment 1.7, outlines that under the draft decision revenue scenario, Essential 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).[3]

As discussed in a confidential section of Attachment 1.8 from UBS, Essential 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 downgrade would significantly impair Essential Energy's financial sustainability.

To improve financial sustainability Essential 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 customers 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 customers. 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 Essential Energy's financial sustainability. Essential Energy's revised proposal would provide sufficient revenues to facilitate a financially sustainable business while the AER's draft determination would not.

Feedback on this revised proposal

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

Channel	**Details**
Email	ourplans@essentialenergy.com.au
Post	Chief Operating Officer Essential Energy PO Box 5730 Port Macquarie NSW 2444
Phone	13 20 80
Online	essentialenergy.com.au/contactus
Twitter	twitter.com/essentialenergy

Customers can also provide feedback and comments on Essential Energy's revised proposal to the AER at www.aer.gov.au.

Essential Energy, Endeavour Energy and Ausgrid jointly manage a Facebook page called Your Power Your Say. We invite you to use it to share your views about our performance as network operators or feedback on this revised proposal.
Facebook.com/yourpoweryoursay

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

1. ABOUT THIS REVISED PROPOSAL

Summary

We consider the AER's draft decision would result in adverse safety and reliability outcomes, and will seriously and adversely impact Essential Energy's financial sustainability.

In some 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 proposals in relation to each constituent decision. We consider that this revised proposal consequently meets the long term interest of our customers with respect to safety, reliability and affordability.

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 distribution 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. The AER rejected our proposal for the majority of these constituent decisions. In response, we have considered the reasons underlying these decisions and whether revisions are necessary to incorporate the changes required by the AER's draft determination. When reviewing the AER's decision we have also considered up to date information made available since submitting our initial proposal in May 2014. Subsequently, we have made revisions to our:

- Proposed service classification proposal, control mechanism and incentive mechanisms.
- Building block proposal for standard control services including forecast operating expenditure, capital expenditure, 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.

The AER's task is to make the correct constituent decisions which, if made in accordance with the decision making framework, will provide a revenue stream that meets the NEO. As well as making changes to incorporate the AER's decisions, we have also identified the elements of our initial proposal that remain unchanged having considered the issues raised in 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 to determine an 'overall revenue allowance'.

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

- Operating expenditure – The AER appear to have misunderstood the functions conferred on it by a Rule change made by the AEMC in 2012.[4] The AER have 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.

[4] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012,* 29 November 2012.

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 Essential Energy's financial sustainability. Overall, we consider that our revised proposal is more preferable to the AER's draft decision in respect of the long term interests of customers. We demonstrate that our revised expenditure forecasts are the efficient costs and reflect a realistic expectation of cost inputs to achieve the operating expenditure and capital expenditure objectives. In turn, this provides for the long term interests of customers by providing for safe and reliable services in the 2014-19 regulatory period.

Background and purpose of revised proposal

Essential Energy is responsible for building, operating and maintaining Australia's largest electricity network. Our distribution network serves approximately 844,000 customers. Geographically, our footprint covers 95 per cent of NSW, as shown in Figure 1-1, from humid coastal environments in the north coast region, through semi-arid desert in the far west, alpine peaks in the south and a grain belt that crosses central NSW from north to south.

A vast network spread across a range of environments presents unique and ongoing challenges. Essential Energy's core focus is on ensuring the safe, affordable and reliable delivery of essential services to homes and businesses across rural and regional NSW. We are committed to delivering better value for our customers by reducing our costs without compromising safety or services.

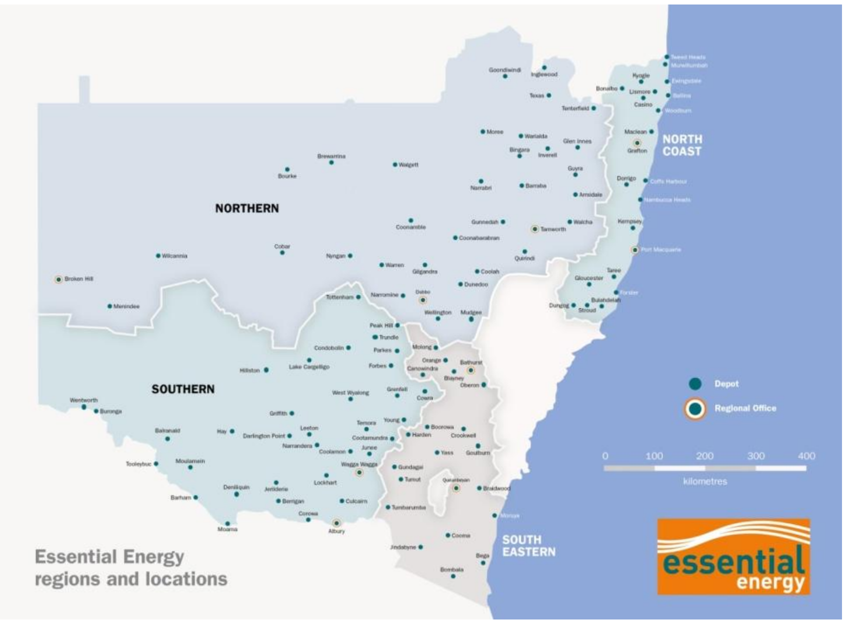

Figure 1-1: Essential Energy's network area

Essential Energy's infrastructure includes approximately:

- 200,000 kilometres of powerlines and cables
- 1.4 million power poles
- 150,000 streetlights
- 135,000 substations
- 400 zone substations.

In the sections below we provide a summary of our initial proposal submitted to the AER in 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.

Summary of Essential Energy's initial proposal

As required by the Rules 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:

- Annual revenue requirements proposed over the 2014-19 regulatory period that directly translated to a reduction in average distribution network charges of 0.20 per cent in real terms for a typical residential customer in each year of the 2014-19 regulatory period.

- These real reductions (i.e. less than inflation) were driven by:
  - substantially lower capital requirements and operational efficiencies pursued by Essential Energy since 2009 and as a result of network reform program initiatives.
  - lower borrowing costs following the Global Financial Crisis (GFC). We proposed a weighted average cost of capital of 8.83 per cent applied to the 2014-19 regulatory period, compared to the rate of 10.02 per cent for the 2009-14 regulatory period.
- The proposed five year capital program reduced from $4.4 billion ($2013-14) approved by the AER for the 2009-14 regulatory period to $2.5 billion ($2013-14) for the 2014-19 regulatory period – a reduction of 43 per cent over the five year period.
- The proposed five year operating program decreased from $2.4 billion ($2013-14) approved by the AER for the 2009-14 regulatory period to $2.3 billion for the 2014-19 regulatory period – a reduction of one per cent.
- Delivering these reductions while still maintaining current network reliability for the 2014-19 regulatory period.

A central objective of our initial 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 run. Our proposal used expert engineering judgment and granular budget analysis to identify the efficient level of expenditure and financial returns required 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 charges.

Affordability was 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 regulatory period, including prioritisation of capital programs. This continued the extensive efficiency gains we had made in the 2009-14 regulatory 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 at or below CPI, while maintaining the reliability and safety of the networks.

To support our claims, we submitted a detailed and fully substantiated initial proposal that complied with the information requirements in the Rules, the AER's regulatory information notice, and demonstrated how our proposal enabled the AER to be satisfied it met the criteria in the Rules. For instance, we set out a detailed attachment addressing the capital expenditure and operating expenditure decision making objectives, criteria and factors.

AER draft determination

As required under the Rules, the AER published a draft regulatory determination for Essential Energy on 27 November 2014. The AER noted that its objective was to determine which outcome would contribute to the achievement of the NEO to the greatest degree. The AER considered that a decision will contribute to the achievement of the NEO to the greatest degree where it was satisfied that it delivers the best balance between the NEO's factors, and it is 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.

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. This means the AER has 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.*[5]

Accordingly, the AER's overview noted that it made a draft decision on the revenue that Essential Energy may recover from its customers in the 2015–19 regulatory period. In total, the draft decision provides an allowance of $3,678.6 million ($ nominal), which represent a reduction of 33.9 per cent compared to Essential Energy's initial proposal.

The AER noted that if it had accepted Essential Energy's proposal, Essential Energy would have been permitted to recover $5,561.6 million ($ nominal) from customers over the 2015–19 regulatory period. The AER was not satisfied that Essential 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 Essential Energy's initial proposal puts forward revenue broadly in line with its 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 Essential 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 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 Essential Energy's network area are reflected in this draft decision include the following:

- Efficiency - The AER believes there are further opportunities for Essential Energy's network services to be provided more efficiently. It considered that Essential 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 Essential Energy's proposal it came to the view that Essential Energy's risk management practices are overly risk averse and result in higher capital expenditure 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

[5] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p16.

noted that system peak demand in Essential Energy's network decreased on average by around 1.13 per cent per annum over the past five years. The AER suggested that recent forecasts indicate that the trend will continue downwards, at least for the next few years. The AER noted that this implies that Essential 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 the 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 drivers were used as the basis for the AER's draft decision and to calculate the total revenue allowance. 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 were 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 Essential Energy's proposal did not adequately incorporate these underlying drivers.

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

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. The AER referred to three key constituent decisions it had made:

- Rate of return - The AER was not satisfied that Essential Energy's proposed 8.83 per cent rate of return is such that it achieves the allowed rate of return objective. It therefore did not accept Essential Energy's proposal. The NER defines the rate of return objective as the rate of return 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 prescribed distribution services. Using the AER's rate of return guideline as its starting point, it allowed a rate of return of 7.15 per cent (nominal vanilla) which, in its view, achieved the rate of return objective and will allow Essential Energy to fund its efficient network investment.
- Operating expenditure – The AER was not satisfied that Essential Energy's proposed forecast operating expenditure of $2,331.8 million ($2013–14) reasonably reflects the operating expenditure criteria. It therefore did not accept Essential Energy's proposal. Its alternative estimate of Essential Energy's total forecast operating expenditure for the 2014–19 regulatory period that it is satisfied reasonably reflects the operating expenditure criteria is $1,436.5 million ($2013–14). The main driver for the AER's substitute operating expenditure forecast was its alternative estimate for what it considered represents an efficient base level of operating expenditure.
- Capital expenditure – The AER was not satisfied that Essential Energy's proposed total forecast capital expenditure of $2,618.7 million ($2013-14) reasonably reflected the capital expenditure criteria. It therefore did not accept Essential Energy's proposal. The AER's alternative estimate of Essential Energy's total forecast capital expenditure for the 2014–2019 regulatory period that it is satisfied reasonably reflects the capital expenditure criteria, is $1,934.3 million. The main driver for the AER's substitute capital expenditure forecast was its reduction in the amount of forecast augmentation and replacement capital expenditure.

Purpose and structure of Essential Energy's revised proposal

The purpose of a revised proposal is to give a DNSP the opportunity to revise its proposal in light of the AER's draft determination and reasons justifying it. 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 reasoning. To the extent that we have not made revisions to our proposal, we consider that this document also comprises a written submission on the AER's draft determination.

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 Essential 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

Revisions to address changes required by AER's draft determination

We have reviewed each of the AER's constituent decisions where the position or value identified in our initial proposal has not been accepted, and subsequently revised our proposal where we consider that the AER's reasoning is appropriate. Through this process, we have also made revisions where new information is available and is relevant in deciding whether to revise our proposal for a matter raised by the AER.

Essential Energy has carefully considered the findings of the AER's draft determinations and has revised our proposal in some areas to address matters raised by the AER's draft determination. We have put forward positions that we consider are preferable in 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 2014-15 financial year, and have incorporated these into our forecasts for the 2014-19 regulatory period.

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

- Chapter 2 sets out the facts about Essential Energy's network, including the challenges faced and the circumstances that heavily influence the costs of operating and maintaining our network. We note that this does not relate to a constituent decision by the AER, however, the AER should properly take into account the circumstances of Essential Energy's network, particularly those elements that are clear cost drivers. The AER should ensure it is properly benchmarking Essential Energy against comparable businesses taking into account predominant drivers of costs. Based on the facts of our network it is clear that the AER has relied on untested and unreliable benchmarking in assessing our initial proposal.
- Chapter 3 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 customers identified during customer engagement is a factor the AER must have regard to when making its assessment under the capital expenditure and operating expenditure 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 charge.
- Chapter 4 notes that we have revised our proposal to incorporate the changes required by the AER with respect to service classification and control mechanisms. In the main, we have not accepted the AER's decision on the application of incentive schemes.
- Chapter 5 identifies the revisions we have made to our building block parameters to address matters raised by the AER in respect of forecast capital expenditure and operating expenditure. We have not revised our proposal for the EBSS carryover or opening asset base 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 inputs, and to incorporate latest information on the allowed rate of return.

- Chapter 6 provides further detail on the revisions we have made to address the changes required by the AER for forecast capital expenditure. We have revised our augmentation capital expenditure to address some of the reasons raised by the AER in the draft determination for rejecting our proposal.
- Chapter 7 provides further detail on the revisions we have made to address the changes required by the AER for forecast operating expenditure. We raise fundamental concerns with the manner the AER undertook in its assessment of operating expenditure including its reliance on benchmarking data, which we consider invalidates its draft decision. When reviewing the AER’s 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 operating expenditure in the 2014-19 regulatory period through higher labour productivity rates. This reduces operating expenditure overall but has consequential impacts on exit costs.
- Chapter 8 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 the NSW DNSPs 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 9 sets out revisions to our alternative control services to address changes required by the AER. We have made minor revisions to our public lighting proposal to reflect some of the changes required by the AER, and have made consequential revisions to our proposed charges to incorporate the latest data on the allowed rate of return. We have reviewed the AER’s changes on metering and ancillary services, and have largely not revised our proposal for the changes required by the AER. We have however accepted elements of the AER’s draft determination for metering services.
- Chapter 10 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 regulatory 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 positions set out in our initial proposal. At a high level, our concern has been that certain constituent decisions of the AER’s draft determinations such as operating expenditure and allowed rate of return are inconsistent with the NER and have not led to a decision that satisfies the NEO.

In this respect, the AER stated that its decisions for the NSW and ACT DNSPs 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.*[6]

We consider that the AER has fundamentally misconstrued the decision making criteria 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 Essential Energy in its draft determination. There are two key areas where we consider there has been misdirection in the AER’s assessment.

[6] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p16.

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

- Clause 16(1)(d) is predicated upon the existence of 2 or more decisions that will or are likely to contribute to the achievement of the NEO. It is only when this precondition is satisfied that the NEL then require the AER to make a choice on a decision that achieves the NEO to the greatest degree.
- The AER's approach to setting Essential 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 operating expenditure and allowed 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 in terms of the substance and merits of such decisions. These concerns are set out in more detail below.

- For forecast operating expenditure we are particularly concerned with the AER's application of its benchmarking, which we show cannot be relied upon to set regulatory revenues in the deterministic manner proposed. Further, the AER's failure to publish its first annual benchmarking report in accordance with the requirements of the Rules has severely compromised the NSW DNSPs' 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 DNSP's would have a period of two months within in which to consider the AER's first benchmarking report given the timeframes of 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 8.

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.*[7]

Below, we set out our consideration on the above views of the AER on the tasks it is required to carry out by the NEL and the NER, in particular:

- The manner in which it performs its functions as specified in clause 16(1)(d) of the NEL.
- The decision it made in the draft decision on the annual revenue requirement.

We are concerned about the manner in which the AER has performed its functions under clause 16(1)(d) of the NER and with the AER's perception that its task is only to determine an 'overall revenue allowance'. We address these further below.

[7] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p14.

Preferable decision

The AER decided to reject the total revenue for the 2015-19 regulatory period proposed by Essential Energy and substituted an amount that is 33.9 per cent less than that proposed. The AER is satisfied that its substituted revenue amount contributes to the achievement of the NEO to the greatest degree.[8] It also contends that it has done this on the basis of clause 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-*
>
> i. *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)*
>
> ii. *Specify reasons as to the basis on which the AER is satisfied that the decision is the preferable reviewable regulatory decision.*

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.

Clause 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.*[9]

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

> *We are not satisfied that Essential Energy's proposed revenue would 'contribute to the achievement of the National Electricity Objective (NEO) to the greatest degree' as required by the rules.*[10]

The AER then replaced Essential Energy's proposed revenue with that it had calculated 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 clause 16(1)(d) of the NEL or alternatively this clause cannot be invoked because the precondition for its application does not exist. Having rejected Essential 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 are not two or more decisions that achieve 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 that choice.

Additionally, instead of identifying two or more decisions that would achieve the NEO for the regulatory period under consideration (i.e. 2015-19) 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 clause 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. Clause 16(1)(d) does not conceive

[8] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p30.
[9] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p14.
[10] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p30.

the task at hand to be one of comparing decisions between periods. This misapplication is apparent in the AER's following statement:

> *The total allowed revenue we have determined is broadly in line with the trend in revenue that was allowed in the **2004-09 regulatory period**. In 2009, there were a range of pressures that led to a step up in total allowed revenue. This draft decision reflects an easing in many of the underlying drivers that influenced the revenue outcome in 2009. By contrast, we have found that Essential Energy's proposal does not adequately incorporate these underlying drivers*.[emphasis added][11]

Our concerns about the AER's decision and justification are 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:

> *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.*[12]
>
> *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 balance 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.*[13]

Setting of annual revenue requirement

The AER has not correctly approached its decision making with respect to determining the annual revenue requirement for Essential 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. Essential Energy contends that this approach is incorrect and not supported by the Rules.

We are not convinced that the AER has properly carried out 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 operating expenditure 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 seemingly implied by the AER. Whilst the AER's building block determination is a component of a distribution determination[14], 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 the NER.

The AER's view is:

> *These legislative changes have made this decision different from 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*

[11] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p11.
[12] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p15.
[13] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p29.
[14] Clause 6.3.1 of the NER.

> *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.*[15]

We have serious reservations about the AER's views expressed above. Whilst the decision to approve or refute 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 Essential Energy's 2014-19 regulatory proposal are in Chapter 6 of the National Electricity Rules, 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) except as otherwise specified in that clause. The main exception concerned the true up of the placeholder revenue for the transitional year.

Chapter 6 sets out the constituent decisions that a distribution 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 distribution determination. It states, the AER must approve the total revenue requirement 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.*

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 operating expenditure, capital expenditure and allowed rate of return. Each of the AER's decisions has a specific decision making criteria. For instance the AER's decisions for forecast operating expenditure and capital expenditure 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.*

The effects of these clauses are that:

- The AER must determine the annual revenue requirement for Essential Energy for each year of the 2014-19 regulatory 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.

[15] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p21.

- The AER must explain its decision for each element with reference to the Rules requirements for each decision.

Concerns with the AER's constituent decisions for operating expenditure and rate of return

The AER's draft distribution 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 relating to forecast operating expenditure 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 operating expenditure 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
- The substance and merits of such decisions.

We address these issues further in the relevant operating expenditure 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 AEMC's 2012 Rule change. This is critical as the AER has contended that recent rule changes afforded it more discretion and *'make the basis of this decisions fundamentally different from previous decisions'.*

Forecast operating expenditure

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 expenditure criteria, with respect to the operating expenditure factors.

In particular, the AER has placed inordinate weight on its benchmarking results, which is only one factor of 11 factors under the Rules. Moreover, clause 6.5.6(e)(12) of the Rules allows the AER to consider any other factors it deems relevant, but the AER's draft decision then used more benchmarking factors, justified under this other factor. In sum, the AER's decision on forecast operating expenditure relies exclusively on benchmarking to both reject our forecast operating expenditure and as the basis for its substituted operating expenditure.

The AER has not meaningfully considered other operating expenditure 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 operating expenditure in the 2012-13 base year was lower than the determination the AER had set in the 2009-14 determination.

By taking this approach the AER has effectively disregarded its 2009-14 distribution determination which set the efficient forecast operating expenditure for Essential Energy and the incentive scheme that it applied to Essential 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 operating expenditure, when it has adopted a base year roll forward approach to determining the efficient level of operating expenditure. Adopting a base year approach to determining operating expenditure, 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 operating expenditure.

The 2009-14 determination made by the AER was the basis upon which Essential Energy set its business objectives, operations and management decisions for this period. Essential Energy fails to comprehend how an actual operating expenditure outturn that is below the efficient operating expenditure allowance determined under a valid AER distribution determination can subsequently be found to be inefficient, as the AER found in its draft decision.

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 capital expenditure and forecast operating expenditure. 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.* [16]

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 rises 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 capital expenditure and operating expenditure 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 Commission 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.* [17]

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[16] AER, *Rule Change Proposal – Economic regulation of transmission and distribution network service providers, AER's proposed changes to the National Electricity Rules,* September 2011.

[17] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p74.

The AER proposed that the criterion relating to demand forecasts and cost inputs was less important than the first two criteria and should be moved to the capex and opex factors. The view was taken in the draft determination that it would position 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.[18]

An additional operating expenditure 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 proposal.[19]

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 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.[20]

Role of benchmarking

The AER consider that it is sufficient to rely on benchmarking analysis to reject and substitute our proposal. 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's determine whether the proposed forecast expenditure reasonably reflects the expenditure criteria. It neither replaces 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 that amendments, such as the need for the AER to take into account benchmarking already existed before the rule change[21]. 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 customer 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 operating expenditure objective 6.5.6(e)(4) was amended to include the reference to the annual benchmarking report.[22] It is imperative to note that this annual benchmarking reports are but one of a suite of information that the AER needs to have regard to in making a determination on Essential Energy's forecast operating expenditure. It is not the only piece of information and certainly it does not displace the NSP's regulatory proposal.

[18] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p74.
[19] Clause 6.5.6(e)(12).
[20] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p89.
[21] Clause 6.5.6(e)(4) of the Rules before the 2012 rule change refers to 'benchmark operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period' .
[22] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p74.

Individual circumstances

The AER has stated that it is not obliged to look at individual circumstances based on its interpretation of the AEMC's intent in developing the 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.*[23]

The removal of individual circumstances of the NSP's from the operating expenditure 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 the consideration of the individual circumstances of the business as recognised by the AEMC in its final position paper for the 2012 rule change.

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 operating expenditure criteria altogether. Explaining the rational 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.*[24]

The AEMC agreed to remove this phrase from the operating expenditure and capital expenditure 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, 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*

[23] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p15.

[24] AER, *Rule change proposal- Economic regulation of transmission and distribution network service providers, AER's proposed changes to the National Electricity Rules,* September 2011, p33.

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.[25]

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 at that point. The removal does not however displace the need for the AER to consider and assess the individual circumstances of Essential Energy in making a decision on our proposed forecast operating expenditure for the 2014-19 regulatory period, something that we consider the AER failed to do.

The operating expenditure criteria (efficient costs of a prudent operator and realistic expectation of demand forecasts and cost 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 operating expenditure 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 distribution 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 they existed prior to the 2012 rule change, made it difficult for the AER to effectively review and assess expenditure proposals. The AER considers that this is because the Rules allow the NSPs unfettered discretion in the methods and models that the NSPs may use to develop and support the expenditure forecast. The AER contented 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.[26] 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 NSP views as appropriate. It is the AER's role to assess the NSP's proposal using any tools it views as appropriate.*[27]

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

> Introduce the expenditure forecast assessment guideline into the regulatory framework. This guideline is to outline how the AER proposes to assess forecast expenditure proposals. The AER, in its framework and approach for a particular NSP, will specify how it intends to apply this guideline in the upcoming distribution determination.

> Introduce the requirement that NSPs must inform the AER of the methodology they propose to use to prepare the forecast expenditure that forms part of its regulatory proposal.

[25] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p8.
[26] AER, *Submission – AEMC Directions Paper, Economic regulation of Network Service Providers*, April 2012, p13.
[27] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p87.

Overall rate of return

The AER has not had proper regard to the current debt structure of the NSW DNSPs which we consider reflects an efficient approach to debt management, with the AER's approach in 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.

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 DNSP.

There are two elements of the AER’s 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

Essential Energy does not agree with the AER’s proposed ten year transition path to the trailing average. As Essential 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 10 year BBB corporate bonds and would not operate to minimise any difference between the return on debt and the return on debt of a benchmark efficient entity with a similar degree of risk as that which applies to Essential 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 regulatory period, provide us with a reasonable opportunity to recover at least the efficient costs of debt finance, nor give rise to charges 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 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. 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.

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 have regard must be had 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.

Essential Energy has considered all relevant evidence and financial models in determining our proposed return on equity of 10.15 per cent. Our point estimate has been chosen from within a reasonable 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. Our point estimate within the range corresponds to the Sharpe-Lintner CAPM estimate of the cost of equity using an equity beta of 0.82 and long term estimates of the risk free rate and MRP.

Why our revised proposal best meets the NEL and NER requirements

As noted in the sections above 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 customers 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 reason to assess whether revisions are necessary in light of the AER's findings. In some 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 26.8 per cent lower than our revised proposal. This in turn is based on three differences in our constituent decisions:

- Our revised capital expenditure is 34 per cent higher than the AER's draft determination.
- Our revised operating expenditure is 62 per cent higher than the AER's draft determination.
- Our revised allowed rate of return is 8.85 per cent compared to the AER's draft determination of 7.15 per cent.

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 direct itself to the capital expenditure and operating expenditure criteria when making its decision, specifically it has not addressed how its substitute forecasts will enable Essential 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.

In this section, we demonstrate how our revised capital expenditure and operating expenditure 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 the safety and reliability sections below. To this extent we have provided an affidavit at Attachment 1.1 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.

Safety issues

Public and Worker 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.

Our revised proposal embodies our commitment to the prioritisation of safety. The proposal has been designed to meet Essential Energy's legislative obligations under the *Work Health and Safety Act 2011* (NSW) (WHS Act), in particular meeting the "primary duty of care".[28]

Essential 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 FMECA / RCM (failure mode effects and criticality analysis/reliability centred maintenance) processes and Essential Energy's Portfolio Investment Plan (PIP) to respectively prioritise both operating and capital expenditure resources relative to risk.

These processes indicate that Essential Energy requires $2.5 and $2.3 billion of capital and operating expenditure respectively to safely manage and operate its business.

A failure to allow Essential 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 Essential Energy employees and the public and would lead to Essential 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 draft determination

The AER has demonstrated an alternate view to Essential 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 achievement of the NEO.

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[29]. 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.

[28] *Work Health and Safety Act 2011* (NSW) s 19.

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

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.*[30]

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.*[31]

In light of these real life examples, we are very concerned with the AER's views that Essential Energy's risk management processes are overly risk adverse[32] and that the AER is proposing that Essential Energy accept greater risks in terms of higher rates of network failure and consequently increased risks to safety, despite Essential 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 to comply with legislative requirements, in particular their health and safety obligations under the WHS Act and the *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW). Essential Energy is also bound to operate by its legislative obligations consistent with the *National Electricity Law* (NEL) and other legislation including the *Electricity Supply Act 1995* (*NSW*). 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, Essential Energy utilises asset related preventative and mitigating 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, Essential Energy introduced the Failure Mode, Effects and Criticality Analysis / Reliability Centred Maintenance (FMECA / RCM) process, to identify 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[33] FMECA / RCM, coupled with regular reviews

[30] Parliament of Victoria, *2009 Victorian Bushfires Royal Commission Final Report*, July 2010.

[31] Legislative Council of Western Australia, Thirty-eighth Parliament, *Report 14 Standing Committee of Public Administration*, *Unassisted Failure*, January 2012.

[32] AER, *Draft Decision - Essential Energy Distribution Determination 2015-16 to 2018-19 – Overview*, November 2014, p10.

[33] 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.

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 Essential 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.

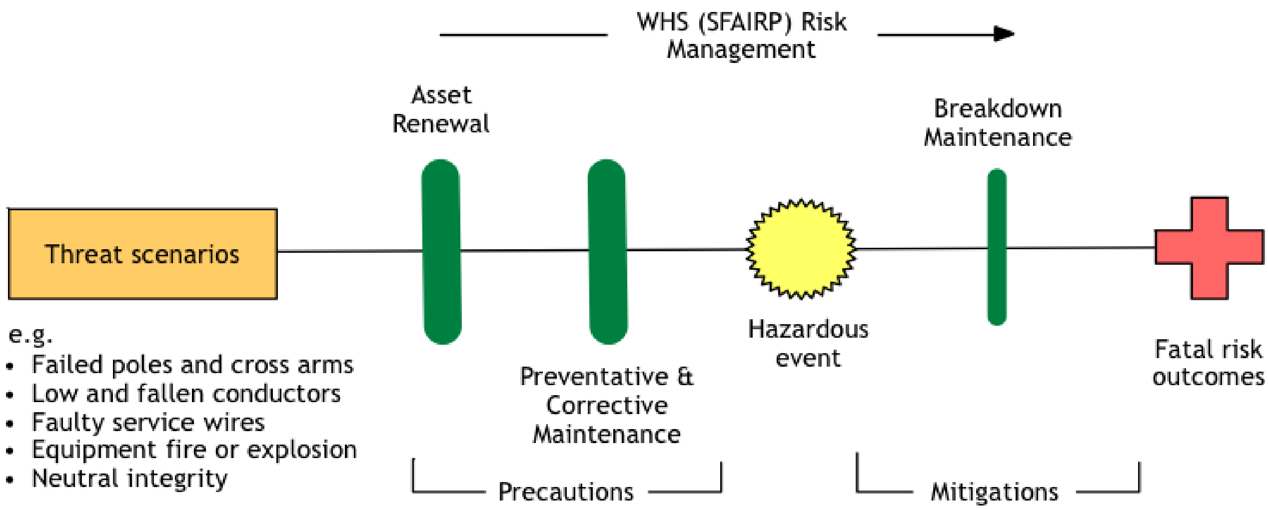

Figure 1-2: WHS (SFAIRP) Risk Management

Essential 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 Essential Energy's organisational human resources would require significant and immediate job reductions in the vicinity of 1,503 representing a 38 per cent 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 NSW Government's Network Reform Program.

A number of Essential Energy's prioritised and successful programs are at risk of being identified as discretionary, due to the proposed reduction in operating and capital expenditure. Essential 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 149 fatalities resulting from motor vehicle collisions and power poles in Endeavour's franchise area (an average of 14.9 fatalities per year). Since the inception of Endeavour'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 franchise area (an average of 5.4 fatalities per year). Factors other than Endeavour Energy's black spot program would have contributed to this improvement. While a number of factors have contributed to that improvement the Black Spot Program is an important road safety initiative acknowledged by the CEO of the Roads and Maritime Authority by letter dated 6 January 2015 (Appendix B of Attachment 3.3).

Safety Risk Assessment

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 2011–15 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.* [34]

Essential Energy has commissioned R2A to conduct a safety risk assessment 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.

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[35] 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 Essential Energy workers and the members of the public will increase from the AER's draft determination where it is proposed that Essential Energy's operating and capital expenditure be significantly reduced relative to recent actual expenditure levels. The R2A report states that the analysis indicates:

> *If Essential Energy were to operate within the constraints of the AER's 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 quadrupling of fatalities from networks hazards is most likely to occur. In addition, the likelihood of the Essential Energy network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) triples as a result of increased equipment failures due to longer inspection cycles.*[36]

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:

The AER draft determination as it stands is in effect, directing Essential Energy to disregard Essential Energy's own determination of what Essential Energy believes is necessary to demonstrate SFAIRP under the provisions of the Work Health and Safety Act 2011.[37]

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[34] Parliament of Victoria, *2009 Victorian Bushfires Royal Commission Final Report*, July 2010, 4.5.1.
[35] Powerline Bushfire Safety Taskforce, *Final Report*, 30 September 2011, (in particular Appendix E).
[36] R2A, *NNSW Asset System Failure Safety Risk Assessment,* January 2015, p4.
[37] R2A, *NNSW Asset System Failure Safety Risk Assessment,* January 2015, p5.

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 DNSPs 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 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.[38]

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, are 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.*[39]

[38] *Work Health and Safety Act 2011*(NSW) s 27(5)(c).
[39] Ian Hanger, *Report of the Royal Commission into the Home Insulation Program* (Commonwealth of Australia, 2014) [1.1.17].

Impact of 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 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.[40]

We are also of the opinion that the proposed operating and capital expenditure allowed for in the draft determination would preclude Essential Energy from complying with its obligations under the WHS Act.

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

Implications for insurance arrangements

Endeavour Energy, Ausgrid and Essential Energy have had jointly insured "common risks" for a number of years, including bushfire liability which is 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 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 125% over the current 2014-2015 insurance position.*[41]

During the 2014-15 renewal we evidenced withdrawal of a number of global underwriters for Australian bushfire liability insurance. This followed 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 NNSW to a level of uninsured bushfire risk.

[40] *Work Health and Safety Act 2011* (Cth) s 19.
[41] Aon Risk Solutions, *The Insurance Advice Report*, 13 January 2015.

Environmental impacts

Essential Energy utilises a number of systems and controls designed to prevent and mitigate environmental impacts in accordance with all relevant environmental legislation. Environmental legal obligations affect all levels of operation, from long-term network planning decisions, through to line construction and maintenance activities.

The AER's proposed capital expenditure and operating expenditure allowances in its draft determination would result in environmental impacts through the reduced capability to execute control programs as part of Essential Energy's environmental management plan.

The consequence of not maintaining environmental systems and controls to their current standard is outlined in Attachment 1.9: Environmental Impacts.

Reliability issues

Supply Reliability

Our initial proposal 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 & 3of the 2014 NSW Design and Reliability Performance Licence Conditions.

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 have 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.

Similar 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 proposals, now updated in our revised proposals, are required to manage our network with the required levels of safety and 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 have rejected those forecasts and proposed the substitution of significantly lower alternative forecasts, with reductions on the order of 20-40 per cent to both capital expenditure and operating expenditure. 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 (Attachment 1.4) and reliability impacts (Attachment 1.5).

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.*[42]

With regard to reliability impacts Jacobs commented 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.*[43]
>
> *and*
>
> *The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a 10 year period.* [44]

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

Inspections and 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.*[45]

Importantly, higher overall costs in the medium to long term do not satisfy the NEO.

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 and 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.

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.

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

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

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

[45] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p49.

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 (and 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 per cent 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 per cent 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 operating expenditure.

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

> *The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a 10 year period.* [46]

As there were more potential sources of unreliability which were discussed but not quantified (including replacement capital expenditure 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.* [47]

Jacobs found that Essential Energy's SAIFI would increase by 14.8 per cent between the base year of 2014/15 and 2020, with SAIDI worsening by 33.2 per cent over the same period.[48] They also found that by 2025 SAIFI would worsen by 29.5 per cent and SAIDI by 50.3 per cent.

While Jacobs did not model the overall cuts to system capital expenditure, they did discuss the drivers for capital investment. They discussed the fact that not committing replacement capital expenditure early enough can result in asset failure with consequences including loss of supply, injury or damage. They noted that, if not committed in time augmentation capital expenditure 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.* [49]

Impact on Licence Compliance and STPIS

We have responded to the STPIS in Chapter 4 of our revised proposal. However, we note that using the analysis referred to above, Jacobs' further modelling of STPIS impacts indicated that asymmetrical STPIS penalties from 1.52 per cent, rising to 3.61 per cent (assuming no cap on the revenue at risk) [50] 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.

Financeability implications of the AER's decision

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

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[46] Jacobs, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p3.
[47] Jacobs, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment,* January 2015, p14.
[48] Jacobs, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p4.
[49] Jacobs, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p10.
[50] Jacobs, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p23.

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 Essential Energy's network will only be maintained with the level of operating expenditure and capital expenditure set out in this revised proposal.

If the AER's draft decision on Essential Energy's allowed revenues over 2014-19 was applied in a final determination, Essential Energy would still need to spend capital expenditure and operating expenditure 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, 6 and 7. In addition, Essential Energy would still be required to meet wage 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 Essential Energy to recover revenues sufficient to cover its benchmark efficient costs, thus causing a material deterioration to Essential Energy's financial sustainability. Providing insufficient revenues to recover Essential 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 operating expenditure allowances. In regards to the appropriate revenue and expenditure allowance for operating expenditure, Professor Newbery noted in his report provided as Attachment 1.6:

> *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.*
>
> *…*
>
> *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.* [51]

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] [52]

[51] David Newbery, *NSW Economic Regulation Report,* January 2015, p17.
[52] David Newbery, *NSW Economic Regulation Report,* January 2015, p27.

Essential Energy has engaged 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 1.7, outlines that Essential 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 1.8 from UBS, Essential 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 have a serious and adverse impact on Essential Energy's financial sustainability.

UBS suggests that Essential 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, operating expenditure and capital expenditure set at the level forecast by Essential Energy in its revised proposal), each business will require a significant reduction in debt in order to remain investment grade over the forecast period. A change in the capital structure from 60 per cent debt and 40 per cent equity to a structure with lower debt would see Essential Energy deviate materially from the credit metrics of a benchmark efficient entity as defined by the AER. Currently Essential Energy enjoys an investment grade standalone credit rating and its debt /equity structure is aligned to the AER's efficient benchmarked capital structure. The draft decision in one action moves Essential 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 a sub 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.

These outcomes are severe, but highly likely if the AER draft determination becomes a final determination and are certainly not in the interest of customers as required by the NEO. The interests of customers 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 customers. 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 customers.

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

2. OUR NETWORK

Essential Energy's network is unique in terms of the geographic area it covers, the terrain it traverses, the vegetation that grows within it and the diversity of weather that passes over it. The scale of assets required to ensure the network physically reaches customers in the most far reaching corners of NSW is like no other network in Australia.

To make an informed decision, it is critical to understand the scale of assets Essential Energy must manage. It is also important to acknowledge that the majority costs associated with electricity distribution are not driven by the number of customers or their demand on the network. Rather, network costs are driven by the number of assets required to deliver electricity to each customer. Whether there are 50 customers connected to one pole or 50 poles connecting one customer, each asset needs to be inspected, safely maintained, and replaced at the end of its life. Comparing the business to similar distributors provides some perspective and the AER has identified a number of Victorian distribution businesses as achieving a level of efficiency that is close to its desired 'efficient frontier'.

> *We have compared Essential 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) rather than the most efficient service provider (CitiPower) in our preferred model.*[53]

Despite the AER recognising that *'**per customer metrics tend to favour higher density service providers**[54][emphasis added],'* it has in many instances used a per customer or demand (driven by customers) basis to make comparisons and draw conclusions from. If per kilometre metrics were utilised, Essential Energy would have been identified as one of the more efficient providers. Essential Energy recognises the need to compare businesses to determine efficiency; however the scale of the network plays a major role in the drivers of cost to deliver network services and should be considered and acknowledged when drawing conclusions. In this chapter, we provide some real life comparisons to these businesses, identify key aspects of operating Essential Energy's network, key differences and the daily challenges we face.

Our distribution network comprises:

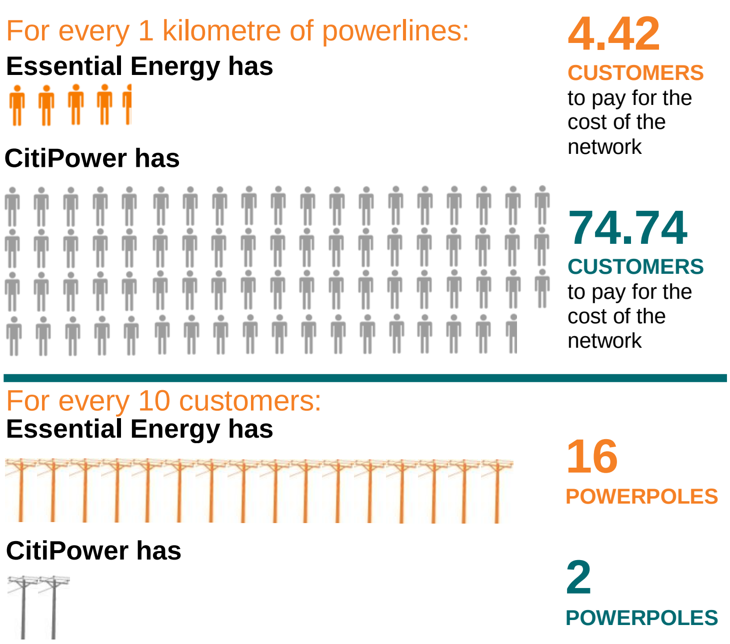
> **844,244 customers across 737,000km² -** approximately 5,000 times the area serviced by Victorian network business, CitiPower.

> **1,377,483 powerpoles –** almost four times the number of poles of AusNet Services, a rural Victorian network business.

> **191,107kms of powerlines –** equivalent to driving around Australia 13 times.

> **1,447 feeders with the longest circuit being 1,900km long –** the same distance as driving from Sydney to Melbourne and back again.

> Every field employee is effectively responsible for **96 kilometres of powerlines.**



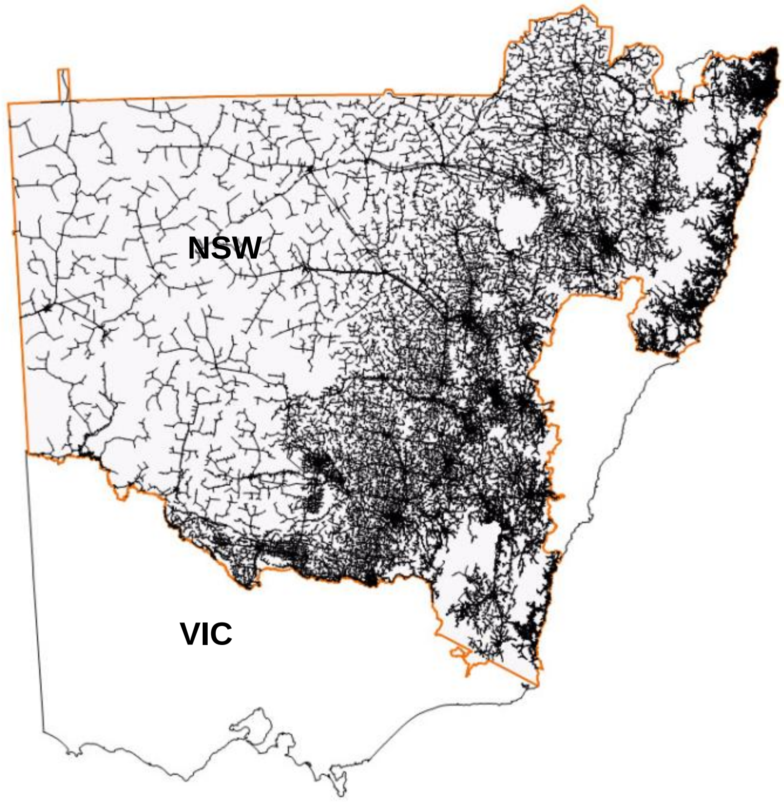
[53] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure,* November 2014, p19.

[54] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure,* November 2014, p79.

The map adjacent demonstrates that the majority of the population on the network is on the East Coast and at a few major regional cities further inland. However, the network still needs to be available to customers throughout NSW.

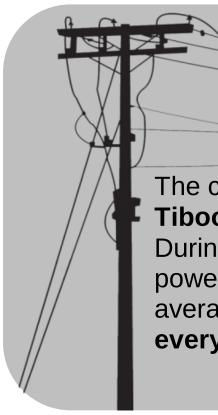
The network stretches from humid coastal environments in the North Coast region, through semi-arid desert in the Far West, alpine peaks in the South and a grain belt that crosses central NSW from North to South.

The combined area of regional Victorian businesses Powercor and AusNet Services networks fits into the Essential Energy network area more than three times.



What challenges do we face?

A vast network spread across a range of environments presents unique and ongoing challenges:



The circuit from **Broken Hill to Tibooburra is 1,900kms** long. During 2013-14 sections of this powerline experienced on average **1 supply interruption every 9 days.**

A radial network

Essential Energy's network is largely radial. This means many of our customers are supplied through one powerline and power can't be re-routed or switched to restore power during supply interruptions. It is often difficult to locate and repair radial line faults due to the distance needed to travel to find the fault on the network, often in adverse weather conditions.

Rural powerlines typically supply much more sparsely populated areas and carry lower loads along very long sections. The longer the feeder gets, the greater the difficulty in maintaining power quality and exposure to environmental factors increases. Essential Energy's network is 80 per cent rural powerlines.

Varying environmental and weather conditions

The weather is one thing no one can control yet it is often the cause of unplanned supply interruptions. Windy conditions along the coast contribute to salt build up on insulators resulting in failures. Timber powerpoles in the North Coast region are prone to increased fungal decay as a result of higher humidity when compared to Victoria and South Australia.

West of the Dividing Ranges, the rural lines traverse open rolling terrain with scattered vegetation. This exposes our network to storms and associated lightning strikes, which often cause damage to our assets. With vegetation, dry land and lightning, comes bushfires. Bushfire prone areas make up a large portion of our network.

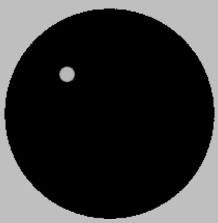
15,409 lightning strikes per year on the network.

Over 900 times the number of strikes experienced by CitiPower.

Accessing our network

During 2013-14, our fleet travelled 61 million kms - equivalent to driving around Australia 4,200 times.

On average, one Essential Energy depot maintains a network area 42 times the size of CitiPower's entire network area.



Travelling across regional and rural NSW can be dramatically different to utilising an urban road. Traffic is not an issue, but access and distance are. Sending our field crews out can impose many challenges, adding time to a journey to restore power or maintain our assets.

Crews often need to utilise access roads that have sometimes not been driven on for years. Often roads are gravel or dirt and after rain can remain impassable for weeks.

Wildlife and vegetation often inhibit access. Crews need to be careful when driving at dusk, during the night and dawn to ensure they reduce the chance of an accident. Fallen trees across roads and access trails often need to be cleared.

The knowledge of our employees at a local level with regards to roads, access paths and the location of network assets is an advantage in identifying the location of faults and finding the right route to get to them.

A large portion of our network cannot be accessed in a standard vehicle meaning a 4WD fleet is required on a daily basis. In alpine areas, we utilise all-terrain vehicles and ski-doos to access the network during snow season. In coastal areas and during floods, we sometimes need to utilise watercraft or helicopters to access the network.

Managing vegetation

Vegetation management is Essential Energy's largest single operating expense, after labour. The costs of managing vegetation around the network are driven by the size of the geographic area the network covers, the volume of trees requiring trimming and the extent to which trees need to be trimmed.

Essential Energy has on average more trees to maintain per span due to a longer average span length than most distributors. The longer a span is the greater clearance zone required to account for blow out of conductors in high wind conditions.

Managing vegetation around the network:

> Reduces the risk of bushfires ignited as a result of contact between vegetation and network assets.

> Reduces the number of reliability performance issues as a result of vegetation contacting the network.

> Reduces the number of outages during storms as a result of trees and branches falling onto powerlines. When a tree falls on a powerline it can sometimes force that powerline to the ground and create a safety issue through the increased risk of electrocution.

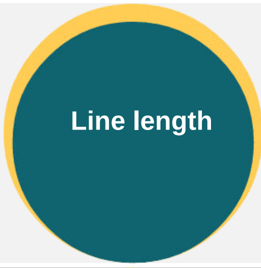
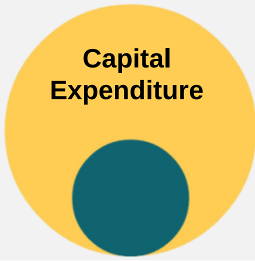
1,067,238 spans on Essential Energy's network are in designated high bushfire zones. The typical clearance zone is 4 metres.

196,736 of AusNet Services spans are in high bushfire zones.

Comparing our network

The AER has identified Powercor, AusNet Services and SA Power Networks as achieving a level of efficiency close to the efficient frontier. The following diagrams provide some comparisons between Essential Energy and the combined characteristics of these three regional and rural based distributors.

It is important to note that while the businesses compare in terms of length of powerlines, the geographic area covered by Essential Energy is 80 per cent larger. This means we have increased travel times to reach assets, as well as a need to ensure resources are located within an appropriate radius of the network and its customers.

	Essential Energy	Combined: Powercor, AusNet Services SA Power Networks	Essential Energy / Our peers combined
The **length of our powerlines is comparable** to the total combined network length of our peers.	191,107km	205,594km	
Essential Energy has **37 per cent of the customers** to pay for the cost of operating the network.	844,244	2,282,978	
We are proposing **54 per cent less capital expenditure.**[55]	$506 million	$1092 million	
We are proposing **25 per cent less operating expenditure.**[56]	$461 million	$611 million	

[55] Essential Energy's proposed average annual capital expenditure 2014-19, compared to the combined most recent actuals published for Powercor, AusNet Services and SA Power Networks ($13-14).
[56] Essential Energy's proposed average annual operating expenditure 2014-19, compared to the combined most recent actuals published for Powercor, AusNet Services and SA Power Networks ($13-14).

Managing a network of this nature requires an efficient level of capital and operating expenditure that is commensurate with the assets it needs to maintain. The use of benchmarking and comparisons to other distributors is discussed in further detail in the following chapters however; this comparison provides a high-level overview to demonstrate the size and scale of Essential Energy. It also demonstrates Essential Energy does compare favorably to the distributors identified by the AER as close to the efficient frontier.

The table below provides some additional comparisons that further demonstrate the key differences and challenges Essential Energy faces with operating such a large distribution network.

Table 3-1: Network comparisons

	Essential Energy	Powercor	AusNet Services	SA Power Networks
Customers[57]	844,244	753,913	681,299	847,766
Area (km^2)[58]	737,000	150,000	80,000	178,000
Customers/km of network	4.42	10.20	15.56	9.65
Poles[59]	1,377,483	547,567	372,147	744,857
The average age of assets[60]	32.9 years	28.6 years	28.7 years	44.7 years
In 2013-14 customers were without power for an average of:[61]	181 minutes	139 minutes	133 minutes	168 minutes

Conclusion

Essential Energy's network is unique in terms of the vast geographic area it covers, the environments it is exposed to and the comparatively low number of customers it serves.

Our assets traverse an area three times larger than Victoria to serve customers right across NSW, while adhering to the requirements of the *NSW Electricity Supply Act* (1995)

The costs of operating a network of this nature are driven by the number of assets and their locations, not simply the number of customers or demand on the network.

[57] AER, *State of the Energy Market 2014*, 19 December 2014, p67.
[58] AER, *State of the Energy Market 2014*, 19 December 2014, p67.
[59] *Regulatory Information Notices*, provided to the AER, 2013-14.
[60] *Regulatory Information Notices*, provided to the AER, 2013-14.
[61] *Regulatory Information Notices*, provided to the AER, 2013-14.

3. OUR CUSTOMERS

> Our ongoing customer engagement tells us that providing a safe, reliable affordable electricity supply remain the top priority for customers.
> Essential Energy has undertaken additional customer research since the AER's draft determination was published and this feedback has been reflected throughout our revised proposal.
> The AER's draft determination appears inconsistent in the investigation and application of the collective customer research.
> Customers do not want to trade off safety and reliability for reduced charges.

Summary

Essential Energy maintains that the plans and expenditure outlined in our initial proposal reflect customer sentiment and respond to research and insights that highlight a need to maintain a safe, reliable and affordable electricity supply. This sentiment was informed by genuine and clear customer engagement activities and research on core elements of our initial proposal over many months prior to submission.

The AER's draft decision, as well as submissions from other stakeholders, challenged the customer engagement and research undertaken by Essential Energy and the way in which these outcomes informed our proposal. We welcome comments from the AER, Consumer Challenge Panel (CCP) and other stakeholders to improve and further build on our process and approach.

The key outcomes from our proposal have been further strengthened by additional research and engagement activities following the submission of our initial proposal, presented here within. This includes additional willingness to pay research using choice modelling methods.

This chapter provides:

> The AER's draft decision in relation to our customer engagement activities
> Our position on stakeholder engagement
> Customer engagement under the rules and our comments regarding the way the AER has applied its assessment of customer engagement to form a view on a preferable decision under the NEO
> An overview of our customers and the summary of findings from engagement and research undertaken prior to the initial proposal
> Findings from recent research and customer engagement activities; and
> A response to submissions on our proposal regarding customer engagement practices and outcomes.

The AER's draft decision and Essential Energy's position

The AER assesses our customer engagement as part of the capital expenditure and operating expenditure factors when making its decision on whether to reject or accept our proposed capital and operating expenditure 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 our initial proposal.

Overall, Essential Energy consider that the AER has not raised significant issues with our engagement processes nor provided new evidence to prompt a revision to our initial proposal.

It is not entirely clear how the AER has utilised its findings from customer engagement when making its decisions on capital and operating expenditure. The AER's decision on forecast operating expenditure suggests that it may have taken into account customer feedback in our proposal on charges as a reason for rejecting our proposed operating expenditure. The AER however did expressly consider customer preferences in its analysis of whether its overall decision is more preferable under the NEO. The AER 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 its draft decision the AER:

> *Acknowledged the short amount of time to implement the AER's Consumer Engagement Guidelines for network service providers following their publication in November 2013 however, noted the breadth of submissions did not support our proposal as being in the long term interest of customers*[62]**:**

The AER's statements demonstrate that it has taken a very narrow view of the long term interest of customers. Essential Energy's customer engagement activities presented in the initial proposal and supported in this revised proposal confirm customers' want to retain current service levels.

Essential Energy has a long solid history of customer and stakeholder engagement across a range of mediums and channels for a number of years. As a business, we are committed to being part of the communities in which we operate. However, our approach was formalised with the introduction of the AER's Consumer Engagement Guidelines.

> *As a business, we are committed to being part of the communities in which we operate.*

Activities conducted prior to the release of the final Guidelines and the formalisation of our approach through the development of a stakeholder engagement framework provided a solid platform to inform our plans for managing the network over the 2014-19 regulatory period. Essential Energy will continue to work on improving our long term customer engagement strategy in an effort to build on findings and work with a broader range of customer and stakeholder groups.

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 charges, citing the '*unprecedented level of consumer participation*' as a foundation for its decision. Essential Energy supports the increasing participation of customers in the regulatory process, including stakeholders representing different customer cohorts.

In this respect, the AER has ignored material from our customer engagement activities which confirmed that our customers want us to retain our current service levels. Instead the AER has relied on the anecdotal information from both the CCP and a small number of stakeholder submissions as opposed to the mass market customer base.

In its draft decision the AER:

> *Noted that Essential Energy had undertaken engagement activities, but not presented compelling evidence of how our proposal adequately incorporates the views and concerns of our customers based on its own consultation with customers:*[63]

Essential Energy's revised proposal aligns to the views determined through research and customer engagement in terms of proposing an asset management plan and associated capital and operating expenditure that promotes prudent and efficient spending.

Attachment 2.2 to Essential Energy's initial proposal included an attachment entitled "How customer engagement informed our regulatory proposal". This document highlighted the instances in which engagement and research was utilised to inform our position and provide insights into the long term interests of customers around issues regarding reliability, outage management and affordability.

The core of our research and engagement found that customers from a broad range of segments expect us to safely deliver a reliable electricity supply to their premise. The 2009-14 regulatory period saw a significant increase

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[62] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview,* November 2014, p27.
[63] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview,* November 2014, p27.

in charges for the distribution network component of the end bill to customers. Customers and our stakeholder groups made it very clear they would not support such large increases again. Essential Energy's revised proposal aligns to these views in terms of proposing an asset management plan and associated capital and operating expenditure that promotes prudent and efficient spending. Safety for the public and our employees will remain our number one priority. We maintain that our proposal presents this view whilst driving cost efficiencies through capital governance processes and programs to reform operating expenditure.

Based on information in its draft decision the AER conducted the following engagement activity with customer groups or stakeholders, in addition to considering submissions and the views of the CCP:

> Hosting a public forum on July 10, 2014

> Metering workshop on September 11, 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 customer views. We contrast this engagement with Essential Energy's detailed level and breadth of customer engagement detailed in our initial proposal and this revised proposal. Details of the research and engagement outcomes that align to the revised proposal can be found in the section 'Revised proposal engagement outcomes'.

In its draft decision the AER:

Stated that customers indicated that they were not offered opportunities to express preferences for service standards and costs which were backed by pricing impact information:[64]

Essential Energy has undertaken additional choice modelling research to further understand the preferences of the customer with regards to service levels and pricing.

This provided customers with the opportunity to respond to different service levels when aligned to price points via an online survey. This research, conducted in December 2014, found that while price is a driver of customers' selection of potential service offerings, the majority are not prepared to sacrifice reliability and safety for lower charges.

These findings support previous research and insights provided through engagement activities and programs that customers want to maintain current levels of service, are not willing to pay more for increased levels of service and see little benefit in a trade off in charges for reduced service levels. Research findings are discussed in detail under 'Choice Modelling Research'.

…customers want to maintain current levels of service, are not willing to pay more for increased levels of service and see no benefit in a trade off in charges for reduced service levels.

Furthermore, IPSOS Research has provided an assurance of the methodology utilised in the June 2012 research as part of its research report included in Attachment 3.1.

In its draft decision the AER:

Highlighted metering and public lighting as specific areas the business needs to do significantly more work in to give customers more say in the services we provide:[65]

The introduction of the AER's F&A provided a basis for further consultation with stakeholders on options for future meter pricing. In May 2014 Networks NSW conducted a Retailer's Forum to provide advance notice on metering charges in its proposal. We acknowledge submissions from Origin and PIAC which indicated that we developed our metering proposal independent from customers.

[64] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview,* November 2014, p27.
[65] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview,* November 2014, p65.

In response to this, we will be evolving our communications to customers regarding meter choices into the future, through ASP's and customers directly via relevant channels such as the website to ensure customers are informed about the available options and associated costs. In addition, we acknowledge that further consultation is required on exit fee that does not create sovereign risks or introduce cross subsidies between customers.

We also note that the NSW Government has released a policy on the market led rollout of smart meters in NSW[66].

Essential Energy has taken a number of steps to develop a long-term approach to engaging with relevant stakeholders regarding our public lighting proposal. The introduction of a Streetlighting Consultative Committee following the submission of the initial proposal was welcomed by the AER and regional NSW councils as a platform to discuss and inform public lighting service level requirements within the communities in which we operate public lighting assets.

In its draft decision the AER:

> *Noted that there was broad stakeholder disappointment that Essential Energy departed from the AERs rate of return guideline with little or no consultation with customers and without demonstrating that these variations are made in the long term interests of customers or represent the efficient costs of an efficient benchmark firm:*[67]

It is not correct to state that Essential Energy has departed from the rate of return guideline with little or no consultation with customers, and without demonstrating that these variations are made in the long term interests of customers or represent the efficient costs of an efficient benchmark firm. Throughout the rate of return guideline consultation process including stakeholder forums, Essential Energy has consistently publicly advocated a return on capital that minimises the impact of short term volatility in financial markets on regulated revenues and consequently customer charges over time. As the guideline recommends, we have also clearly outlined in our initial proposal the reasons for our approach as:

- Essential 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 windfall losses 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 Essential Energy to move away from an approach to financing determined as efficient by the AER to an approach it considers is inefficient (the use of swaps) to manage the interest rate risk introduced by the guideline's short term transition.

The detailed reasons are further elaborated in an attachment to our initial proposal from CEG 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.

It is also noted that while the rate of return guideline sets out the methodologies the AER proposes to use in estimating the allowed rate of return for distribution determinations, the guideline is not binding on a DNSP in developing its regulatory proposal or the AER in making a distribution determination.

Customer engagement and the AER's decision making

Understanding the ability for customer engagement and research to inform the AER's draft decision is important when comparing the criteria in the Rules to the regard of the draft decision.

[66] The Hon Anthony Roberts MP, *NSW Gets Smart About Meters,* 28 November 2014.

[67] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview,* November 2014, p28.

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

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

It is not clear that the AER's decisions to reject our forecast capital expenditure and operating expenditure amounts and to substitute the AER's forecasts for those amounts have been based on its assessment of our customer engagement process or findings. For capital expenditure, the AER stated:

> *We have had regard to the extent to which Essential Energy's proposed total forecast capex includes expenditure to address consumer concerns that have been identified by Essential Energy. On the information available to us, including submissions received from stakeholders, we have been unable to identify the extent to which Essential Energy's proposed total forecast capex includes capex that address the concerns of its consumers that it has identified.*[68]

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

> *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 Essential Energy – particularly those expressed in the consumer-focused overview provided as an attachment to its regulatory proposal.*[69]

We consider that our initial proposal has already taken this view into account when we developed our total forecast capital and operating expenditure for the 2014-19 regulatory 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 6 and 7, we have made revisions to our proposed capital expenditure and operating expenditure to reflect latest information on the efficiencies we expect to achieve in the 2014-19 regulatory period.

The AER in their draft decision stated:

> *The newly formed Consumer Challenge Panel (CCP) played a significant role in our processes of assessing the proposal before us. The panel advised us on issues that are important to consumers and provided consumer perspectives, particularly those of residential and small business consumers. Member of the panel bring with them experience in regulation, networks, economics, finance and consumer engagement.*[70]

In response to this we note Dr Gill Owen's *'The potential role of Consumer Challenge in energy network regulation in Australia: a think piece for the Australian Energy Regulator".* In her research, Dr Owen stated:

> *If the Consumer Challenge Panel is giving views that are very different from that obtained from market research (surveys, focus groups) and/or consumer organisations (including a new Consumer Advocacy*

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[68] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure,* November 2014, p31.

[69] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure,* November 2014, p23.

[70] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p82ibid., 1, p82 .

Body if one is established), then the regulator will want to look carefully at why such differences may be occurring. There may be very good reasons for such differences, but this does mean that the regulator still retains its central role of balancing different interests and reaching judgements.[71]

With this in mind Essential Energy notes the vast differences in views from the research and engagement we have undertaken when compared to the advice and anecdotal evidence provided to the AER from the CCP. We encourage the AER to consider why there is such a large gap in the customer sentiments reported by Essential Energy versus those reported by the CCP.

Our position on stakeholder engagement

Essential Energy acknowledges the importance of genuine customer engagement and utilising these findings and insights to inform our plans for managing the network. This ensures our investment and approach to network management is in line with service expectations of customers.

Being the largest network service provider in NSW, and delivering electricity to 95 per cent of NSW requires a strong connection to the communities in which we operate. Formalising this relationship through key stakeholder engagement activities ensures the view we receive is representative of the many and diverse customers and stakeholders we serve.

Being the largest network service provider in NSW, and delivering electricity to 95 per cent of NSW requires a strong connection to the communities in which we operate.

To formalise our approach to customer engagement, we have developed a Stakeholder Engagement Framework (Attachment 3.2) based on a widely recognised spectrum of engagement, the IAP2 continuum[72]. The framework describes the type of engagement activities customers and stakeholders can expect from the business. It also identifies what we cannot do and why.

The framework aims to meet the following objectives:

- Identify our customers and collate baseline data on demographics and social preferences via segmentation and data analysis.
- Deliver structured research programs to understand the key concerns, and our customers' and stakeholders' priorities for investment.
- Establish and maintain relationships with key stakeholder groups that represent the concerns of customers.
- Identify key gaps in customer education related to the electricity supply chain and programs of work to establish relevant educational tools for customers and stakeholders.
- Provide relevant, effective and two-way communication channels that allow customers and stakeholders to provide feedback and receive information in a timely and easy manner.
- Report back to customers and stakeholders regarding outcomes and the reasons for those outcomes.

The engagement activity and research we conducted for our initial proposal gave us key insights into the concerns of customers. These insights have helped shape our business objectives to ensure we consistently make decisions that are not only in the best interests of safety, are economically viable, technically feasible and compatible with the environment, but also match our customers' needs.

These insights have helped shape our business objectives to ensure we consistently make decisions that are not only in the best interests of safety, are economically viable, technically feasible and compatible with the environment, but also match our customers' needs.

[71] Dr Gill Owen, *The potential role of Consumer Challenge in energy network regulation in Australia: a think piece for the Australian Energy Regulator,* 13 March 2013, p26.
[72] International Association of Public Participation, *Public Participation Spectrum.*

The framework and our engagement activities will be reviewed and refined on an ongoing basis to ensure a relevant and timely approach to two way communication and education activities. Alongside this, Essential Energy is revising its approach to customer service through the development of a customer commitment statement. This statement means that we will listen to and respect our customers, safely deliver on our promises and place customers at the centre of everything we do.

In addition, we are improving our tools to effectively communicate with customers in a way that is relevant and timely to them, whilst ensuring methods of communication are efficient and provide value to the customer.

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 that our initial proposal include a plain English overview for customers and a description of how we engaged with electricity customers and sought to address any relevant 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 operating expenditure and capital expenditure. 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 capital expenditure and operating expenditure.

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 customers 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.*[73]

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

> *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.*[74]

We also note that the AER's Consumer Engagement Guidelines emphasise the importance for network businesses to commit to genuine and ongoing customer 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.*[75]

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.*[76]

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[73] AER, *Consumer Engagement Guideline for Network Service Providers*, November 2013, p12.
[74] AEMC, *Australian Energy Market Commission, Rule Determination*, November 2012, p36.
[75] AER, *Consumer Engagement Guideline for Network Service Providers*, November 2013, p8.
[76] AER, *Consumer Engagement Guideline for Network Service Providers*, November 2013, p5.

We endorse the intent of these statements as well as the AER's clear acknowledgement that meaningful customer 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.*[77]

Consistent with the intent of this approach, Essential Energy developed a strategic and long term approach to its engagement with customers and stakeholders, previously outlined in our initial proposal and further explained in this chapter.

This included our commitment to embed engagement practices into our business processes, continue to engage with customers beyond our initial proposal and to review and renew our engagement strategies and activity.

The AER has ordained clear expectations and acknowledgments with respect to customer engagement activity; however it appears that these have not been appropriately adhered to by the AER when passing judgement on Essential Energy. This is viewed to be particularly unreasonable in this instance given the late publication of its Consumer Engagement Guideline.

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.

The AER's Consumer Engagement Guideline for network service providers was utilised to formalise Essential Energy's approach to customer and stakeholder engagement. With this formal approach in place to complement research activities, the business has been able to garner feedback and insight into the interests of our customers in line with the considerations of the guideline. The AER has stated in its draft decision that it has *"considered how the service provider"*[78] undertook systematic, consistent and strategic engagement with customers on issues significant to both parties. Table 3-1 provides the elements of consideration and Essential Energy's approach and outcomes with regards to these elements.

Table 3-1: Demonstration of compliance with AER consumer engagement guideline

Guideline element	Demonstration of approach and outcomes
Equip customers to participate in consultation	Essential Energy took a multi-pronged approach to customer engagement. Our research program utilised surveys and focus groups from within our network area. The Your Power, Your Say Facebook page in conjunction with Networks NSW provided a digital platform for social media users. In addition, our customer and stakeholder groups, the Rural Advisory Group and the Customer Council represent a range of regional and rural customers from across our footprint area. The contact details of these groups are available online and community members are encouraged to engage with these members directly to share issues and insights.

[77] AER, *Consumer Engagement Guideline for Network Service Providers*, November 2013, p12.
[78] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Overview,* November 2014, p65.

Make issues tangible to customers	Electricity distribution network management and its associated services is a complex issue. However, through our plain English proposal and choice modelling research, we aimed to provide tangible examples of the key risks and benefits of our proposal. Choice modelling provided pricing options for differing service levels. Charges was presented 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 impacts of inspecting our network from the air; and the time taken to repair defective streetlights. Customers were then asked to select their most preferred option from these different choices. The Your Power, Your Say Facebook page presented easy to read and understand infographics. These illustrations provided tangible examples of a range of issues directly related to the regulatory proposal process.
Obtain a cross section of views	The two research programs we undertook as part of our engagement process were done within the Essential Energy footprint from a statistically valid representation of customers from each of the four regions – North Coast, South Eastern, Northern and Southern NSW. Alongside this, the formation of the Streetlighting Consultative Committee provided views and insights from the perspective of local government in regional NSW. Meetings with industry bodies such as Cotton Australia and the NSW Irrigators Council provided meaningful insights into the needs of famers in regional NSW.
Consider and respond to customer views	Our research and engagement activities set the priorities for our proposal: safety, reliability and affordability. The themes of these insights and priorities flow through each element of our revised proposal. Our stakeholder engagement framework acknowledges what we can do and what we can't with regards to placing the final decision in the hands of the customer. It also provides a process for responding to customers and engaging with them on key issues. In some instances, we cannot fulfil the wishes of the customer due to safety or regulatory reasons. When this occurs we aim to respond to customers with an explanation of this.

Our customers and stakeholders

Essential Energy has approximately 844,000 customers spread across 95 per cent of NSW. In contrast to the other NSW DNSPs, Essential Energy has one of Australia's lowest average customer densities of four customers per kilometre of powerline. Understanding the types of customers and stakeholders within the footprint area is important in further targeting activities designed to better understand the needs and concerns of customers. In addition, this understanding is also critical to informing communication and education strategies for business as usual programs.

Customers can also be considered in terms of their connection classification. Recognising this is also important when discussing concerns with customers and stakeholders to ensure relevance and appropriate choice of communication channel.

In broad terms, the following connection classifications apply to Essential Energy's customer base:

- Residential
- Small to medium businesses
- Large low voltage
- High voltage.

Residential and small to medium businesses account for the majority of customers. These groups have different network needs than those of large low voltage and high voltage customers. Essential Energy's vast network area spans considerable geographic diversity. It covers regional cities, rural farmland and remote rural locations that are home to customers and stakeholders with varying concerns and requirements. With this in mind, Essential Energy customers can be classified into groups and represented by the following:

> Local councils
> Farming groups and associations
> Community welfare organisations
> State Government departments
> Regulators
> Community advisory panels
> Business chambers
> Large energy users
> Retailers
> Accredited service providers
> Community associations.

Customer satisfaction

Essential Energy places strong value on the level of satisfaction of our customers and tracks this score on a quarterly basis[79]. Satisfaction research is conducted in our footprint area with 450 representative customers to understand instances and satisfaction levels around interactions with the business. The variables measured include:

> Unplanned and planned supply interruptions
> Streetlights
> Vegetation management
> Infrastructure maintenance
> Meters
> Construction
> Customer interaction.

The last three quarters of results have shown consistently positive results, to a target of 80 per cent.

Table 3-2: Customer satisfaction index scores

	Apr – Jun 2014	July – Sept 2014	Oct – Dec 2014
Score	82.7%	81.7%	81.6%

The survey focusses on the customer experience associated with the measured variable in terms of the process, undertaking or outcome of the provided service. For example, the survey seeks to understand the customer perspective during supply interruptions. These results were further collaborated by choice modelling research conducted in December 2014 that found customer satisfaction to be at 79 per cent[80] – within three per cent of the results recorded in the dedicated quarterly research.

These results reflect continued acceptable satisfaction from our customers around the service levels we currently provide, a reflection of customer sentiment to maintain current levels of reliability and response to supply interruptions. We will continue to measure and monitor these scores to ensure our service levels align to the concerns of our customers.

[79] IPSOS Research, *Customer Satisfaction Index,* April – December 2014.
[80] IPSOS Research, *Willingness to pay for network services*, December 2014, p16.

Engagement activities prior to the submission of our initial proposal

Research

Essential Energy conducted a major research program in June 2012. This research was designed to explore customer's knowledge, attitudes and behaviours around electricity consumption and investment decisions. The research consisted of a survey with a sample size of over 1,000 Essential Energy network customers. This was complemented by eight focus groups. Research findings identified six clear customer values. These values are the essence of what is important to our customers and the ways in which they would like Essential Energy to manage these issues as a network distribution business.

Utilising the values obtained from our research has already informed a number of network programs. Such insights are also useful when making investment and business decisions, because they ensure the concerns of the customer are considered when planning capital and operating expenditure. Table 3-3 outlines the customer values, what they mean, what we are doing to address them and how service levels would change if the draft decision were to be fully implemented. Understanding the potential impacts is important to demonstrate the impact changes in service levels would have when compared to the identified values of our customers.

Table 3-3: Customer values

Customer value	What it means	What we are doing	How service levels would change
I expect you to be there when I need you	**Customer engagement** Customer service is there when I need it	> We have a call centre available 24 hours a day, seven days a week to answer all customer questions and provide service > We have dedicated social media and online feedback forms to ensure customers can contact us how they like > We are working on new customer communication tools to make it even easier to contact us when you need to.	> Social media would be monitored in business hours only > Customer communications tools would not improve, only remain stable > Call centre wait times would increase by up to 30 per cent.
I want information to plan and make decisions	**Outage Management** Outages are less intrusive	> Where it is safe to do so, we utilise live line crews to maintain the network > We are meeting our reliability targets set in licence conditions > We bring crews in from neighbouring depots to get jobs done safety and efficiently > Our communication tools make it easier to find out about current and future planned outages in your area.	> Crews will make the network safe and return to restore power in business hours only > Depot closures would drastically increase travel time to outages in regional areas > Planned outages would only occur in business hours, increasing the level of disruption to businesses.
I need confidence in my electricity supplier	**Reliability** Maintain reliability at current levels. Ensure no feeder falls below minimum standard	> We plan to maintain our current level of reliability > We have a program that ensures we work on the areas with poor reliability to provide a better service to customers no matter where they live.	> The risk of reduced reliability would increase with the increase in asset inspection cycle times > The number of poor performing feeders would increase > Increased number of supply interruptions for life support customers.

I expect my charges to be fair	**Affordability** Network charges are contained	> We will contain the network component of electricity charges to CPI over the next five years > We are making productivity and efficiency gains as well as reducing capital and operating expenses.	> Network charges would decrease > Streetlight charges would increase > Customer charges for ancillary services would be consistent and enforced > Customers would be charged for vegetation work around private poles in bushfire zones.
I need the knowledge and tools to make a difference	**Demand management** Customer are making educated and informed decisions	> We provide education about the services we provide > We will ensure that the information we provide is relevant, timely and accessible for our customers.	> Information and education would be limited to safety messages and online content.
You should be doing more to protect the vulnerable	**Hardship** Sustainably reduce disconnections for non-payment	> We are following legislation that ensures we don't disconnect customers at certain times > We are working with retailers to examine options for disconnections for non-payment.	> A hardship policy would be instated to support the increased number of direct customer charges in relation to vegetation management and ancillary network services.

Your Power, Your Say

In addition to research, we participated in a joint Facebook campaign called Your Power, Your Say. This campaign was designed to provide an easily accessible and real-time view of customer preferences. Customers are provided information and asked questions about elements around network management such as charges, reliability, streetlighting, electricity tariffs, demand management, drivers for network investment, past investment strategies, solar generation, safety and customer communication methods.

We note comments from the PIAC on this joint campaign:

> *While PIAC welcomes this attempt by Networks NSW to engage with consumers through Facebook, social media is only one part of a broader consumer engagement puzzle.*[81]

In response to this, it is important to highlight that the Your Power, Your Say campaign was only one tool in a suite of engagement activities employed by Essential Energy. We acknowledge the audience constraints when utilising social media, however also maintain the use of the channel provided insights and feedback on a range of issues in a relatively quick timeframe through an easily accessible and measurable tool.

The page reached almost 1.6 million Facebook users and resulted in almost 62,000 interactions with customers. Insights gathered from this page also supported findings from our research program as well as providing specific examples of areas of customer concern.

> *[Your Power Your Say Facebook page]…reached almost 1.6million Facebook users and resulted in almost 62,000 interactions with customers.*

Customer and stakeholder group meetings and presentations

In the lead up to the submission of the initial proposal Essential Energy held numerous meetings with our Customer Council and Rural Advisory Group. In addition, meetings were also held with the NSW Irrigators Council and Cotton Australia. Each of these interactions provided insights about different customer segments. There was strong

[81] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination*, 8 August 2014, p29.

recognition for the need to provide a reliable service to our customers, however also strong opposition for further increases in charges and a drive for more innovative tariff options for large regional customers.

In addition, Essential Energy participated in Networks NSW led forums with peak industry bodies and energy retailers. These forums represented a solid step change in the combined approach to stakeholder engagement. Essential Energy is committed to expanding on these opportunities into the future.

Revised proposal engagement outcomes

Choice modelling research

For our revised proposal, we conducted a range of further customer and stakeholder research and engagement activities to understand current attitudes, sentiments and willingness to pay with regards to network services. This research found the majority of customers found reduced reliability and service levels unacceptable, even when factored against price.

The research was designed to further understand current customer sentiment and willingness to pay for particular network services. We provided 869 customers weighted across the Essential Energy footprint area 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 clearances; the timing and interval between aerial inspections; and the time taken to repair defective streetlights. Customers were then asked to select their most preferred option from these different choices. Refer to Attachment 3.1 for the full report on this research.

The research provided insights and themes that collaborate and support the findings from the June 2012 research conducted for the initial proposal submission. The choice modelling research found:

> While price is a driver of customers' selection of potential service offerings, the majority 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 Essential Energy customers. Specifically, increases in the time taken to restore power to houses, such as only during business hours 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. The status quo was modelled on Essential Energy's current reliability standards.

> 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 customers, indicating a need to enhance education to customers around the importance of vegetation management and the role it plays in safety and reliability – which are of value to our customers.

> Customers indicated a preference for ongoing aerial inspections. When introduced in the context of asset maintenance and reduced bushfire risk, customers saw value in the ongoing aerial inspection of the network.

> The duration of repair time for faulty streetlights did not impact a customer's overall preference for particular service scenarios. This insight will be provided to councils to inform discussions regarding service levels and the Public Lighting Code 2006.

> 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 when presented with the lowest quarterly price at $197, 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, this scenario 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 the option that presented the current network quarterly charge coupled with current service levels rated the second highest in terms of acceptability.

These research findings support insights and research gathered from our customers and stakeholders over a long period of time that indicate customers long term interests for electricity include maintaining the reliability and response to supply interruptions they currently experience.

With this in mind, we maintain our position on providing a service that meets the long term priorities of our customers through the delivery of safe, reliable and affordable supply of electricity.

Supporting these findings, Dr Gill Owen reports that:

> *…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.*[82]

We believe that utilising primary research and supporting these findings with relevant secondary research is a reasonable and relevant way to ensure the customer sentiment and insight we present is validated in order to support our revised proposal.

Engagement activities

Essential Energy has a long history of customer and stakeholder engagement through both formal and informal activities such as safety education programs, social media campaigns, customer communications about what we are doing on the network, as well as asking dedicated customer groups what they think about our plans.

> *Essential Energy has a long history of customer and stakeholder engagement…*

Streetlighting Consultative Committee

Essential Energy recognises the submissions received on our public lighting proposal as well as the comments made by the AER regarding the need to shift our approach to consultation and engagement with regard to public lighting.

Essential Energy has responded to this feedback following the submission of our initial proposal through enhanced communications to local councils regarding our public lighting proposal. These communications led to a forum held on 24 September 2014. Following this Essential Energy established a Streetlighting Consultative Committee on 26 November 2014, with its first meeting held on 11 December 2014.

This Committee has representatives from a number of Regional Organisations of Councils (ROCs) as well as individual local councils and an observer from the AER. To date, this Committee has agreed to a Charter and the approach to feeding back outcomes and requesting information from all councils in Essential Energy's network area. Key themes to emerge from the initial meeting of this group include:

- Acknowledgement of the positive step towards more effective and long-term engagement with councils around public lighting.

[82] Dr Gill Owen, *The potential role of Consumer Challenge in energy network regulation in Australia: a think piece for the Australian Energy Regulator*, 13 March 2013, p15.

> Consensus for a transition for the introduction of increases to public lighting charges.
> Recognition of the need to formulate a more cost effective approach to public lighting service delivery, outside of the requirements of the Public Lighting Code 2006, a code that is potentially outdated and not geared towards assets spread across a very large geographic area.
> Commitment from Essential Energy to a more consultative approach to lighting tender processes, service level agreements and access to data.

A 12 month schedule of quarterly meetings with the Committee has been agreed and confirmed.

The business welcomes this consultative approach to public lighting management and looks forward to working with councils to finalise service level conditions that provide a prudent outcome whilst maintaining the safety and the security of local regional communities.

The business welcomes this consultative approach to public lighting management…

Rural Advisory Group and Customer Council

During the preparation of this revised proposal, the business met with our Rural Advisory Group and Customer Council. In these meetings we presented the potential impact to service levels for customers should the AER's draft decision be implemented in full through tangible examples.

Both groups expressed deep concern over the implementation and back dating of cuts to operating and capital expenditure:

> *Mr Hughes however believes the decision will result in massive job losses in the thousands, drastic safety, maintenance and reliability issues, and depot closures. The question is whether customers are prepared to sacrifice reliability for a 13 per cent reduction in their bill. The AER says yes, common sense says no.*[83]

The groups also expressed concerns with regards to reliability and increased number of supply interruptions at the risk of not being able to pump water for livestock and crops on the hottest days of the year, or not being able to milk cows on dairy farms, meaning a loss of business and distress to the stock. Essential Energy recognises the concerns of our rural and remote customer base and believes it is important to acknowledge the differing issues and concerns of these customers as opposed to those in more urban or metropolitan areas.

In summary these meetings highlighted the groups' expectation and support of our priorities of safety, reliability and affordability. Again, these groups highlighted their view that service levels should be maintained, but charges need to remain stable.

…service levels should be maintained, but charges need to remain stable.

Correspondence received

In addition to stakeholder meetings and additional research, Networks NSW and the AER received letters from NSW Fire & Rescue and the NSW Rural Fire Service highlighting their concerns regarding the AER's draft decision and the impact this would have on vegetation management in bushfire prone areas as well as safety concerns regarding reduced response times. NSW Fire & Rescue highlighted their concerns:

> *I fear that the impact of the draft determination could be a greater reliance on Fire & Rescue NSW in storm situations, due to the numbers of available utility staff and less vegetation 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 longer periods at "wires down" incidents.*[84]

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[83] David Hughes, *Future of Essential Energy in doubt,* Forbes Advocate, 30 December 2014, p5.
[84] Letter to NNSW CEO Vince Graham from NSW Fire & Rescue, Greg Mullins AFSM, 4 December 2014.

Similarly, NSW RFS highlighted concerns regarding changes to vegetation management. Which in essence describe the need to enforce a financial penalty should a DNSP not deliver the vegetation management required around the network:

> *The NSW RFS has regulatory powers to require that any bush fire hazards be removed. In discharging its legislative responsibilities, if the NSW RFS becomes aware that vegetation clearance around power lines or other electricity infrastructure is not adequate, it would be obliged to issue a notice on the electricity provider to undertake works, or undertake the works itself at the providers cost.*[85]

Essential Energy recognises the views of these essential service organisations and has therefore reflected these concerns in our revised proposal to ensure our vegetation management program is reflective of the process required to effectively manage the vast amounts of vegetation around the network. We believe failure to do this increases costs to fault and emergency work, increases risk of fines to complete rectification work as well as costs associated through any litigation as a result of failure to provide a safe and reliable network to our customers.

We have rejected cuts to vegetation management and replacement capital expenditure that would modify public safety risks or our bushfire risk mitigation plan.

NSW Roads and Maritime Services highlighted concerns regarding the potential to reduce or exclude the Black Spot Pole Program and the potential safety impact this may have across the three NSW distribution business areas.

> *Roads and Maritime supports the continuation of investment in the Black Spot Pole Program, with its objectives of improving driver safety and reducing the impacts associated with vehicle and power poles.*[86]

Essential Energy maintains that safety will continue to be our number one priority. With this in mind, we will continue to work with NSW Roads and Maritime Services to improve safety in black spot areas with the aim of reducing powerpole collisions. The safety implications of the AER's draft decision are explored in Chapter 1, Safety issues.

A full report on stakeholder engagement activities and outcomes with these groups is provided in Attachment 3.3: How engagement informed our revised proposal. This attachment also includes copies of correspondence from these stakeholder groups.

Submissions to our initial proposal

Essential Energy received 25 submissions to our initial proposal and 30 submissions to our proposal on public lighting.

Submissions on our public lighting proposal were received from local councils, regional organisations of councils and consultants employed on behalf of local councils. Our revised approach to engagement on public lighting is provided in the 'Engagement Activities' section.

Submissions on our initial proposal came from a range of stakeholders including retailers, public advocacy groups, industry bodies, community organisations, energy associations and the CCP. The key themes of these submissions and our response are provided in the sections below.

Consumer Challenge Panel (CCP)

The CCP was established by the AER to assist it in making better regulatory determination's by providing inputs on issues of importance to customers. Essential Energy has had opportunities to meet with the CCP to discuss and provide clarification on our transitional regulatory proposal. The CCP provided a submission on Essential Energy's initial proposal entitled 'Jam Tomorrow?'

[85] Letter to NNSW CEO Vince Graham from NSW Rural Fire Service, Shane Fitzsimmons AFSM, 5 December 2014.
[86] Letter to NNSW CEO Vince Graham from NSW Roads and Maritime Services, Peter Duncan, 6 January 2015.

This submission presented a position on the approach to research and engagement for the three NSW distribution businesses. It did not distinguish in detail, the different approaches from each of the businesses. In particular it did not recognise the different research methodologies utilised by the businesses. In response to this, IPSOS Research, the consultants utilised to undertake the research in June 2012 have provided a response to this perspective. It is provided in Attachment 3.1.

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

> *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.*[87]

… Essential Energy does not believe it is credible for the AER to accept anecdotal evidence to reject our findings on customer preferences.

Given the significant implications of the above statement, Essential Energy does not believe it is credible for the AER to accept anecdotal evidence to reject our findings on customer preferences. We note we have found no facts presented to show customer preferences as suggested by the CCP.

We do note that there is widespread acknowledgement in submissions on our proposal that Essential Energy has embarked on extensive customer engagement activity. The CCP also rejects the findings of Essential Energy's research, based on the methods used in the research. It states that this is reason enough, to reject our findings on customer preferences, and seek substitute untested views.

…[customers] did not prefer worsening reliability as a trade-off for a reduction in charges.

The general finding from Essential 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. The majority did not prefer worsening reliability as a trade-off for a reduction in charges.

We also note that the CCP refers Essential 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 customers are willing to pay less for reduced reliability:

> *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.*[88]

Essential Energy sought advice from WPD, via Ausgrid, about these findings from the CCP. It states that it was misleading for the CCP to make this claim. It explained that while about 15 per cent of its customers voted for a deterioration of services via the willingness to pay research, the remainder in fact supported the maintenance or improvement of network service levels.

WPD went on to explain that further road testing of customer 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 reduction in charges.

> *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.*[89]

[87] CCP, Sub-Panel 1, *Jam Tomorrow?*, August 2014, p11-12.
[88] CCP, Sub-Panel 1, *Jam Tomorrow?*, August 2014, p12.
[89] Email to Ausgrid from WPD, December 2014.

The CCP stated the WPD research conclusions were a possible source of alternative evidence to reject Essential Energy's findings on customer 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.*[90]

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

The CCP noted their regard to customer engagement being integrated into the day to day work of the staff teams of any business, at no additional cost. Essential Energy believes that to actively engage with customers and stakeholders on an ongoing basis requires resources to manage communications and activities as part of their role. In addition, the delivery of statistically valid research comes at a cost to the business.

However, we believe the value in this research is delivered through its ability to inform the capital and operating plans of the business, and potentially defer significant amounts of expenditure as a result of reflecting the long-term interests of our customers and stakeholders. In addition, this research also informs the way our customers want us to communicate with them.

Public Interests Advocacy Centre (PIAC)

The PIAC[91] noted they only had contact with Essential Energy as part of a Networks NSW event and were therefore not able to comment on our specific customer engagement activities. However, PIAC submitted significant feedback and responded to specific issues raised in the AER's Issues Paper.

Accessibility of information

PIAC welcomed the attempt by networks to produce a plain English summary of our proposals. However suggested it was too long and included too much text. They suggested an additional two page high level summary of network spending to "*sit in front of the 10 page summary*".

Essential Energy appreciates this feedback for future submissions.

PIAC considered the length and volume of the proposals. Noting that such *"vast proposals also compromises the regulatory process, hampering consumers ability to engage and stretches the resources of the AER".*[92] Whilst we acknowledge that the content supplied with our submission was extensive, we believe it is important to provide all available data to ensure transparency and support our proposal in full.

PIAC also suggested that "*DNSPs should be encouraged to present key facts about their plans to consumers in a frank way"* and not *"shy away from constructive criticism of their operations and should produce their documents with this in mind".*[93]

While this recommendation was directed at the AER to assess documents for a balanced picture or whether they are dominated by *"spin"*[94]*,* Essential Energy would like to acknowledge these comments and note our attempt to produce a plain English summary that highlighted both positive and negative facts about the initial proposal. In addition, we have acknowledged our need to improve our approach to customer and stakeholder engagement through, for example, the establishment of our Streetlighting Consultative Committee.

[90] CCP, Sub-Panel 1, *Jam Tomorrow?*, August 2014, p12.
[91] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination,* 8 August 2014, p28-32.
[92] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination,* 8 August 2014, p30.
[93] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination,* 8 August 2014, p30.
[94] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination,* 8 August 2014, p13.

Clarity re the role of customer engagement

PIAC presented a view that *"Networks NSW has been keen to tell consumers that their views will be considered, but could have gone further in explaining just how this could occur (and the possible limitations on giving weight to consumer preferences)".*[95]

Essential Energy provided an attachment to our initial proposal entitled "How engagement informed our regulatory proposal". Similarly, our revised proposal also has an attachment (entitled "How customer engagement informed our revised proposal". In addition to this, our Stakeholder Engagement Framework (Attachment 3.2) aims to demonstrate how we can and cannot respond to customer preferences in line with the safety, legal and regulatory requirements of managing a network business.

Opportunities to express preferences as part of customer engagement

PIAC noted they were *"hopeful that NSW network businesses will seek to engage with their customers about the dollar impact of, for example, reducing reliability standards".*[96]

Essential Energy undertook additional choice modelling research following the publication of the AER's draft decision in November 2014. These results are published in Attachment 3.1.

Effectiveness of businesses in responding to customer concerns

PIAC is of the view that Essential 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. Essential Energy's CEO Vince Graham has consistently and publicly expressed the view that more needs to be done to reduce our costs to help keep the pressure off future increases in network electricity charges. In particular, we have delivered the NSW Government's reform program. This program directly funds additional rebates to low income households and families struggling with electricity costs. We note the success of this program in a media statement from the NSW Government that states more than 780,000 participants has received the Low Income Household Rebate.[97]

The charges submitted as part of this revised proposal are built to reflect the true cost of providing not only electricity to a customer's premise, but also ensuring the business can service all the additional costs of providing that service such as maintaining the network, responding during storms, communicating with our customers when they need it most and ensuring they have a safe, reliable and affordable power supply.

Energy Markets Reform Forum (EMRF)

The EMRF provided substantial feedback on the customer engagement strategies and outcomes of the NSW distribution businesses. The EMRF highlights particular concern for the approach to demonstrating and exploring customer preferences for reliability at differing charges points:

> *For a consumer to make an informed decision on such a line of questioning requires a better understanding of what loss of reliability would occur for what lesser cost. As it stands, the DB's (distribution businesses) cannot make assertions about this aspect of consumer desires.*[98]

Essential Energy has taken steps to further clarify the customer position on reliability and its trade off with charges through choice modelling research conducted in December 2014. The findings from this research build on previous

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[95] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination,* 8 August 2014, p31.

[96] PIAC, *Moving to a new paradigm: submission to the Australian Energy Regulator's NSW electricity distribution network price determination,* 8 August 2014, p31.

[97] The Hon Anthony Roberts MP, *More households benefiting from energy rebates*, 19 December 2014.

[98] Energy Markets Reform Forum, *NSW Electricity Distribution Revenue Reset – A response*, July 2014, p16-17.

research and customer engagement activities that support our original view that broadly, customers want to maintain current levels of reliability, however ensure charges remain stable.

In addition, the EMRF suggested that engagement was only utilised to support decisions already made by the business:

> *Essentially the timing of the CE (customer engagement) so far would have been so late in the process of preparing the revenue proposals to do little more than support the decisions already made by the DBs.*[99]

Essential Energy disagrees with this statement. The business has a long solid history of engaging with and working with our customers through research and consultation practices. We have an ongoing catalogue of insights from our customers and stakeholders. Recognising the preferences of customers change over time, the business has sought to enhance our program of strategic engagement to deliver additional insights that provide a view of the long term interests of our customers, as driven by the AER's Consumer Engagement Guideline.

We have an ongoing catalogue of insights from our customers and stakeholders.

Specific conversations with our Customer Council and Rural Advisory groups provided valuable insights and shaped our approach to capital expenditure and deferring programs of work as well as the way in which we execute on our vegetation management program. In addition, these groups directly shaped the approach and outcome of our plain English proposal.

AGL

AGL endorsed the increased level of customer consultation carried out by the NSW DNSPs, however stated it is usually difficult to draw specific conclusions on value based on responses. Specifically, they doubted our ability to:

> *…link changes in customers' reliability to relevant changes in costs; and therefore determine whether customers would choose to forego a change in potential service reliability for a financial benefit.*[100]

Essential Energy conducted a range of research and engagement activities in the lead up to the submission of the initial proposal 2014-19. In response to the submissions from various stakeholders, we undertook additional research based on a statistically valid approach to choice modelling to understand customer preferences with regards to service levels and charges.

Part of this process involves excluding responses that were done in a timeframe deemed too quick to return a true insight into the customers preference. That is, the respondent answered without providing due thought and consideration to the answers they were providing. This ensures the final results of the research complete are a true reflection of the customer. We stand by this methodology to understanding and measuring preference when aligned to charges.

Cotton Australia

In their response to Essential Energy's initial proposal, Cotton Australia asked that:

> *Essential Energy be prevented from 're-assigning' tariff classes without first engaging with the affected consumer. Especially as the network itself has identified fair pricing and the provision of timing and accurate information as key components of its customer value strategy.*[101]

[99] Energy Markets Reform Forum, *NSW Electricity Distribution Revenue Reset – A response*, July 2014, p16-17.
[100] AGL, *Submission to the AER,* 8 August 2014, p12.
[101] Cotton Australia, *Submission on DNSPs Regulatory Proposals*, 10 July 2014, p4.

Under the *Distribution Network Pricing Arrangements Rule* changes, effective 1 December 2014, Essential Energy is required to consult with customers or their retailers regarding any change to their tariff from 1 July 2015. This Rule change also ensures that tariff structures are based on long run marginal cost and are reflective of the cost of providing supply to the customer.

The AEMC states in its rule determination:

> *There will also be more consultation with consumers and retailers in the development of network prices, and the process for setting prices will be more transparent. Network prices will be finalised earlier, allowing consumers and retailers more time to prepare for price changes.*[102]

Essential Energy intends on complying with and delivering effective consultation on network charges as part of its ongoing stakeholder engagement strategy.

UnitingCare Australia

A submission from UnitingCare Australia noted:

> *Essential Energy state that they are committed to the IAP2 public participation spectrum, but also state that the level of consumer empowerment is not possible for energy issues. UnitingCare Australia believes this is not correct, and indicated that there are unrealised opportunities for network businesses to participate in more effective consumer engagement.*[103]

Essential Energy aims to be transparent in all aspects of our approach, delivery and results of customer and stakeholder engagement. The IAP2 defines the public participation spectrum component of 'empower' as '*placing the final decision in the hands of the public'.* While we will continually strive to gauge the views of customers, stakeholder groups and industry bodies to highly inform our plans and approach to network management and customer service, the customer preference is one component of the decision making process. These decisions also need to factor safety, reliability, legal and regulatory requirements. However, Essential Energy always aims to ensure the customer is at the centre of everything we do.

Ethnic Communities' Council of NSW

The Ethnic Communities' Council of NSW (ECC) highlighted areas where Essential Energy could better target its engagement to reach customers 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 ECC 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 ECC 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. We look forward to continuing this level of engagement with the Council.

Once this draft document is complete, we aim to provide a supporting document that assists with reaching and communicating with CALD customers and stakeholders in regional NSW.

In our most recent research in December 2014 we asked customers to provide information on their CALD status. This found that 13 per cent of customers spoke a language other than English. Essential Energy recognises this is a growing stakeholder group within our footprint area and have already taken steps to improve our translation services and on customer facing documents, forms and letters.

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[102] Australian Energy Market Commission, *Rule Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p1.
[103] UnitingCare Australian, *Submission to The Australian Energy Regulator,* 3 September 2014, p21.

Conclusion

Customer and stakeholder engagement activities and research completed as part of the initial proposal process, in addition to those completed to support the submission of our revised proposal provide a clear and genuine picture of the insights and views of our customers. These views have been utilised to inform our revised proposal to ensure the long term interests of our customers are considered when developing our plans for capital and operating expenditure.

We acknowledge our need to continue the delivery of enhanced stakeholder engagement activities to ensure we have an ongoing, time relevant view of our customers' preferences, in order to shape the services we deliver.

Essential Energy has clearly outlined our activities and approach that adhere to the AER Consumer Engagement Guidelines.

4. SERVICES AND PRICE CONTROLS

> - The AER's draft decision on many elements of the classification of services and control mechanisms has been incorporated into our revised proposal.
> - We consider that unless the AER accepts our revised capital and operating expenditure proposals, then the EBSS, CESS and STPIS should not apply for the reasons set out in this Chapter.

Summary

The AER was required to make a number of important decisions before we submitted our initial proposal. The AER made these decisions as part of the framework and approach process including 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 regulatory period.

We have revised our proposal as follows:

- Classification of services - We have revised our proposed service classification to adopt the AER's minor changes in 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 embedded within a meter.
- Control mechanisms - We have revised our proposal to amend the formulae for elements of the AER's draft decision on the control mechanism for standard control services.
- Incentive schemes – We consider that unless the AER accepts our revised capital and operating expenditure proposals, then the EBSS, CESS and STPIS should not apply for the reasons set out in this Chapter.

Service classification

Clause 6.12.1(1) of the NER requires the AER to make a decision on the classification of the services provided by Essential 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 the Stage 1 F&A paper on 25 March 2013. Our proposed classification of services for the 2014-19 regulatory period essentially adopted the AER's classification with a few proposed clarifications 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 Essential 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 proposed by the AER in its draft decision 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, with some minor changes to the description of some services for clarity and the insertion of one existing service that had dropped out of the AER's classification table. These changes are highlighted in yellow for ease of review at Attachment 4.1.

Minor clarifications and re-groupings

The AER incorporated the clarifications proposed by Essential 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 F&A paper.

Changes to classification of load control

In its draft decision, the AER amended its definition of the network services and metering services groups to effect its decision on the classification of load control services.[104] Effectively, the AER's decision means that when the load control functionality is embedded within the meter, it is classified as an alternative control service. In all other cases, the load control device is a standard control service.

> *…the AER's decision means that when the load control functionality is embedded within the meter, it is classified as an alternative control service.*

We have revised our initial proposal to accept the AER's decision to re-classify load control services. The AER's approach is consistent with the methodology we used to prepare our initial proposal, and therefore we have not made a revision to our charges for metering services.

We had included the incremental costs of the load control device when deriving the charges for our metering services. 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.

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 uses an alternative 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. However we do not consider the recovery of these costs themselves constitute a new standard control service.

In Chapter 9 we note our reservations with the AER's draft decision due to the administrative burden created. 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 charges and to our proposed control mechanism.

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 its Stage 1 F&A paper. 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

[104] 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 devices in its description of "Type 5 and 6 metering provision, maintenance, reading and data services" (which fall in the Metering Services group).

to be a revenue cap. The AER also set out its proposed approach to the formulae that give effect to the control.[105] 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 charges of individual services. The AER also set out its proposed approach to the formulae that give effect to the control.[106]

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 as follows:

- 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 charges and a charging 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 of 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.

The AER's draft decision makes a substantial change in the control mechanism for standard control services in relation to its proposed treatment of exit fees for metering services.

Standard control services formula

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

- 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 damage – 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 control service to recoup residual metering costs when a customer exits the metering services we provide. The AER has specified that the B-factor will include the residual metering costs and we have revised our formula to incorporate the AER's decision. Essential Energy agrees with the mechanisms for recovering these residual capital costs and administration costs as decided by the AER in the draft decision. However, we do not consider the recovery of these costs themselves constitute a standard control service such as one described by the AER as a 'meter transfer' service. We did not propose such a service in our classification proposal included in the initial proposal.
- DUOS unders and overs account (included a tolerance limit) - The AER rejected the inclusion of DUOS unders and overs as part of the control mechanism, and has now included this as part of compliance with the control mechanism. We have revised our proposal to incorporate the AER's decision. We discuss this further in chapter 10, including our reasons why a tolerance limit should be placed on the DUOS unders and overs account.

[105] AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, March 2013.
[106] AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, March 2013.

- Pass through – The AER have 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 incorporates the same formula as specified in Figure 14.1 of section 14.5.5 of the AER's draft decision.

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 16.6.5 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.

Application of incentive schemes

Clause 6.12.1(9) of the Rules require the AER to make a decision on how any applicable EBSS, CESS, STPIS, demand management and embedded generation connection incentive scheme (DMEGCIS) or small scale incentive scheme is to apply to the DNSP. The Rules require the AER to set out its proposed approach in the Stage 2 F&A paper.

The AER published its decision in the Stage 2 F&A paper in January 2014. The AER determined they would apply an EBSS, CESS, STPIS and DMEGCIS in the 2014-19 regulatory 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 would apply for the 2014-19 regulatory period. Our initial proposal sought modifications to the application of certain incentive schemes in the transitional year (2014-15) and offered further suggestions 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 Stage 2 F&A paper. In the sections below, we set out the AER's draft decision and our response.

Efficiency Benefit Sharing Scheme in the 2014-19 regulatory 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 regulatory 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 period.[107] For the 2015-19 regulatory period, the AER specified that version 2 of the EBSS will apply to Essential Energy.[108]

The AER's draft decision is 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 operating expenditure and the likely incentives Essential 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.

We have not revised our proposal to incorporate the AER's changes. The EBSS provides a symmetrical (neutral) incentive for a DNSP to pursue efficiencies when the operating expenditure target is set at the efficient and prudent level.

… if the AER makes the correct operating expenditure decision, it would have no need to suspend the application of the EBSS.

Our contention is that if the AER makes the correct operating expenditure decision, it would have no need to suspend the application of the EBSS. We consider that the AER's reasoning demonstrates that the substitute forecast operating expenditure is unachievable, and would result in harsh penalties if we spend above the allowance. As

[107] AER, *Stage 2 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, January 2014.
[108] AER, *Stage 2 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, January 2014.

we demonstrate in Chapter 7 of our revised proposal, our view is that the AER's responsibility is to set efficient and prudent operating expenditures that meet the operating expenditure objectives. If the AER make such a decision, then an EBSS incentive would provide a symmetrical incentive.

However, if the AER decide to not accept our proposal, and substitute a lower amount, then we agree that an EBSS would not provide a neutral incentive and therefore should not apply.

Capital Expenditure Sharing Scheme in the 2014-19 regulatory 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 setting out the CESS.[109] In its distribution determination for the transitional year (2014-15), the AER specified that no CESS applies.[110] This is consistent with the requirements of the Transitional NER. The AER proposes to apply its CESS in the 2015-19 regulatory period in accordance with its published guidelines.

Essential Energy's initial proposal agreed that the CESS should apply in the 2015-19 regulatory period, consistent with the AER's proposed approach to its application to Essential Energy stated in the Stage 2 F&A paper.

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

However, if the AER decide to not accept our proposed capital expenditure and substitute a lower amount, then we consider that a CESS would not provide a neutral incentive, and therefore should not apply, in the same vain as our comments above on the EBSS.

Service Target Performance Incentive Scheme in the 2014-19 regulatory 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 regulatory period.

Our proposal agreed with the AER applying a scheme from 2015-16 onwards, and set out a revenue at risk of 2.5 per cent. 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 per cent 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 design elements. Attachment 4.2 sets out why we have not revised our proposal for the AER's draft decision on these design elements. The method used by the AER to determine target adjustments was based on performance trends observed on Ausgrid's network. This approach displays a lack of rigour and Essential Energy has instead utilised actual performance figures for our own network to calculate target adjustments. Essential 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. We draw the AER's attention to an incorrect supposition that investment undertaken in the 2009-14 regulatory period will have an impact on our targets in the 2014-19 regulatory period. However, we accept that a portion of the AER's decision relates to a change in the mathematics of

…the AER should have based its assessment on our own average performance over the last five years, rather than set a [STPIS] target which is significantly above our current performance based on trends in an unrelated and dissimilar network.

[109] AER, *Better Regulation – Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.
[110] AER, *Essential Energy - Placeholder determination for the transitional regulatory period 2014–15*, April 2014.

how the target is calculated and we have revised our proposal to incorporate this change.

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 27 per cent and 38 per cent respectively (or of similar magnitude), 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 1.5). 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 Essential Energy's SAIFI would increase by 14.8 per cent between the base year of 2014-15 and 2020, with SAIDI worsening by 33.2 per cent over the same period.[111] They also found that by 2025 SAIFI would worsen by 29.5 per cent and SAIDI by 50.3 per cent.

Jacobs noted:

> *The modelling demonstrates that there will be a significant impact as a result of the reduction in maintenance expenditure, particularly over a 10 year period.*[112]

As there were more potential sources of unreliability which were discussed but not quantified (including replacement capital expenditure 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.*[113]

A STPIS incentive framework in the 2014-19 regulatory 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 impacts indicated that asymmetrical STPIS penalties from 1.52 per cent, rising to 3.61 per cent[114] (assuming no cap on revenue at risk) over the regulatory determination period, would result from the AER's draft determination if implemented.

Essential Energy considers that unless the AER accepts our revised capital and operating expenditure proposals, the STPIS should not apply.

Demand Management and Embedded Generation Connection Incentive Scheme in the 2014-19 regulatory period

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) on the same scale 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 initial proposal noted that the Council of Australian Governments (COAG) Energy Council 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 could apply changes to their incentive scheme if a Rule change is implemented in time for our final determination, subject to consultation with Essential Energy.

[111] Jacobs Group Australia, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p4.
[112] Jacobs Group Australia, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p3.
[113] Jacobs Group Australia, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p14.
[114] Jacobs Group Australia, *Networks NSW – Regulatory Revenue Decisions, Reliability Impact Assessment*, January 2015, p23.

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 initial proposal.

Small Scale Incentive Scheme in the 2014-19 regulatory period

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 initial proposal.

5. BUILDING BLOCK PROPOSAL

> - The AER has not accepted many elements of our proposed building block proposal, with knock-on effects on revenue and X-factors.
> - Building block inputs have been revised based in part on changes to capital expenditure, operating expenditure and the allowed rate of return.
> - Regulatory Asset Base (RAB), regulatory depreciation, and corporate income tax have also been revised where considered necessary.
> - The AER's draft determination demonstrates multiple inconsistencies in the assessment and application of available data.

Summary

The AER did not accept the majority of the elements of our building block proposal. For this reason the AER has not accepted our proposed annual revenue requirements and X-factors. We have also 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 charges.

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 capital expenditure, operating expenditure and the allowed rate of return. We have also reviewed the AER's decisions on our opening regulatory asset base (RAB), regulatory depreciation, and corporate income tax, and revised where we considered it necessary. We have not revised our proposed EBSS carryover amount. The resulting building blocks are identified in Table 5-1.

Table 5-1: Unsmoothed annual revenue requirements ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on and return of capital						
Return on capital	601	641	681	720	759	3,401
Return of capital	99	114	130	122	130	594
Operating and tax costs						
Operating expenditure[115]	510	516	489	506	483	2,503
Income tax	66	58	68	90	85	367
Other revenue increments or decrements						
EBSS revenue	(15)	(53)	(48)	39	-	(77)
DMIS revenue[116]	1	(0)	1	1	1	3
ACS adjustment	55					55
Annual revenue requirement (unsmoothed)	**1,315**	**1,276**	**1,320**	**1,478**	**1,458**	**6,846**

Note: Totals may not add due to rounding

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

115 Inclusive of debt raising costs for all years.
116 Inclusive of a DMIA adjustment of $0.6 million in 2015-16.

Essential Energy has revised its proposed annual revenue requirements based on revised inputs into the building block calculation. This section sets out the revised annual revenue requirement, smoothed revenue and X factors. We also address the AER's draft decision on the true up for the transitional year.

The annual revenue requirement, smoothed revenue and X factors were calculated using the Post Tax Revenue Model (PTRM) that incorporated two main amendments, being calculations on debt raising costs and corporate income tax. These amendments, amongst others, were explained in our submission[117] to the AER as part of the current consultation on the PTRM. Tables 5-2 and 5-3 set out the annual and smoothed revenue requirements and the proposed x-factors.

Table 5-2: Indicative annual and smoothed revenue requirements ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Unsmoothed revenue	1,315	1,276	1,320	1,478	1,458	6,846
Smoothed revenue	1,292	1,333	1,366	1,400	1,447	6,837

Table 5-3: Proposed X-factors (%, real)

	2014-15	2015-16	2016-17	2017-18	2018-19
X-factors	10.28%	-0.65%	-0.01%	0.01%	-0.82%

Table 5-4 sets out indicative changes in average annual distribution charges over the 2014-19 regulatory period that result from our proposed annual revenue requirements in the revised proposal, compared to our initial proposal and the AER's draft decision.

Table 5-4: Change in average annual distribution charges based on latest energy forecasts (% change in real charges)

	2014-15	2015-16	2016-17	2017-18	2018-19
Initial proposal*	-0.20%	-0.20%	-0.20%	-0.20%	-0.20%
AER draft determination	-5.11%	-33.09%	-	-	-
Revised proposal*	-1.89%	-1.89%	-1.89%	-1.89%	-1.89%

* Includes metering revenue across all years as well as ANS and ERW costs in the 2014-15 building block requirements.

We also note:

> The AER did not accept our proposed nominated pass through events. We have reviewed the AER decision but do not consider there is a need to revise our proposal.

> We concur with the AER's decision to apply forecast depreciation when establishing the opening RAB for the 2019-24 regulatory period.

Initial proposal

In our initial proposal, we identified the building block components used to calculate the annual revenue requirement for each year of the 2014-19 regulatory period,[118] consistent with the requirements of the Rules. The building blocks relate to the following types of costs:

[117] Networks NSW, *Submission on proposed amendments to post-tax revenue model*, 17 November 2014

[118] We note that while this proposal relates to the subsequent regulatory 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.

- 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 RAB, 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 RAB 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.
- 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 regulatory period. The Rules also enable a revenue decrement arising from the use of assets that provide standard control services for provision of certain other services.

As part of the building block proposal we had also outlined our indicative charges 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 decisions on these matters.

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 RAB, forecast capital expenditure 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 RAB and forecast capital expenditure.
- 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.
- Alternative control services costs – The AER did not accept our proposed public lighting, metering and ancillary network services costs.
- Other revenue adjustments - The AER accepted our proposed shared asset reduction of zero. However the AER reduced our EBSS penalty and DMIA adjustment to zero.

Based on its decision on building block inputs, the AER rejected our proposed annual revenue requirements and X-factors.

The AER also rejected our nominated pass through events.

However it accepted our proposed method to roll forward the RAB to the 2019-24 regulatory period using forecast depreciation

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

We have revised some of our building block inputs to incorporate some of the changes required by the AER in its draft decision. Our revised proposal contains the following:

- The return on capital is consistent with our initial proposal. This includes the revisions to our forecast capital expenditure and proposed rate of return.
- The return of capital is three per cent 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 capital expenditure.
- The operating expenditure is consistent with our initial proposal. The revisions we have made are set out in Chapter 7 of this revised proposal.
- The cost of corporate income tax is four per cent lower than our initial proposal. These are a consequence of changes made to the annual revenue requirement and a correction to the PTRM.
- We have not revised our proposal for EBSS carryover amounts, but have updated the DMIA adjustment to reflect actual 2013-14 results. We note that the AER accepted our proposal on shared asset reduction, so no further revisions are necessary.

Table 5-5 provides our revised return on capital, return of capital, operating expenditure, cost of corporate tax and other revenue adjustments. Further detail is set out in the sections below.

Table 5-5: Unsmoothed annual revenue requirements ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on capital	601	641	681	720	759	3,401
Return of capital	99	114	130	122	130	594
Operating expenditure[119]	510	516	489	506	483	2,503
Income tax	66	58	68	90	85	367
EBSS revenue	(15)	(53)	(48)	39	-	(77)
DMIS revenue[120]	1	-0	1	1	1	3
ACS adjustment	55	-	-	-	-	55
Annual revenue requirement (unsmoothed)	**1,315**	**1,276**	**1,320**	**1,478**	**1,458**	**6,846**

Note: Totals may not add due to rounding.

Return on capital and Return of capital

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

We do not accept the AER's reasons for rejecting our proposed allowed rate of return, opening RAB and forecast capital expenditure and consequently have not revised our proposed return on and return of capital to reflect these decisions. We have provided a detailed response to the AER's decisions on forecast capital expenditure and allowed rate of return in Chapter 6 and 8 respectively.

We do not accept the AER's reasons for rejecting our proposed allowed rate of return, opening RAB and forecast capital expenditure and consequently have not revised our proposed return on and return of capital to reflect these decisions.

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

119 Inclusive of debt raising costs for all years.
120 Inclusive of a DMIA adjustment of $0.6 million in 2015-16.

Value of opening RAB and method to roll forward the RAB in the 2014-19 regulatory period

The AER made adjustments to our proposed opening RAB value as at 1 July 2014 (opening RAB values). We do not agree with these adjustments and have not incorporated the AER's opening RAB values in the calculation of our revised return on capital building block of the annual revenue requirement. The opening value for distribution standard control services and Type 5 and 6 metering services as at 1 July 2014 are set out in Table 5-6 and incorporate the actual capital expenditure for 2013-14. Our revised roll forward model (RFM) is set out in Attachment 5.1.

Table 5-6: Opening RAB value as at 1 July 2014 ($ million, nominal)

	Value as at 1 July 2014
Distribution standard control services	6,788
Type 5 and 6 metering services	95

Movement in provisions

The AER contended that movements in provisions should be excluded from the actual capital expenditure included in the RAB 2008-09 to 2013-14. This is because the AER considers that increases in provisions do not represent actual costs incurred in delivering network services.

We consider that increases in provisions are costs incurred through the profit and loss statement, calculated in accordance with Australian accounting standards, in providing standard control services. The fact that it is set aside and to be paid in the future does not change the nature of it being a cost incurred in providing the services. When determining the appropriate capital expenditure to use in the RFM, the AER must have regard to several factors including the value of the relevant asset as shown in independently audited and published accounts.[121] Our independently audited and published accounts show the actual capital expenditure incurred in each year and includes movement in provisions. These amounts were used in the RFM at Attachment 5.1.

In order to provide standard control services, Essential Energy must employ resources (i.e. staff) and have systems and processes in place to provide this service (e.g. IT systems) and at times (where appropriate and efficient to do so) employ contracted services. A person employed by Essential Energy is entitled to receive a salary and other entitlements which are annual leave, sick leave, superannuation and long service leave in accordance with legally binding Enterprise Bargaining Agreements. The total cost of retaining an employee includes all of these costs, and as such, Essential Energy must bear these costs in order to provide standard control services to customers.

The timing of cash outlays to satisfy these salaries and entitlements that Essential 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. Essential Energy has 'consumed' the service provided by that person at the time the person provided the service (e.g. fixes damage on the network) and the total cost to Essential Energy of 'consuming' that service is the salary and leave 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 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 Essential Energy has incurred in providing network services and that are called upon when the person takes leave, which could be many months after the time that the service for which the costs were incurred was performed. It is a fallacy to assert that movements in provisions are not actual costs incurred in delivering network services.

[121] Clause S6.2.2(7) of the Rules.

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

By endorsing this approach, the AER can be seen 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 Essential Energy's, be reflected in provisions in the AER's financial accounts).

Essential 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 5.2.

Essential Energy has also carried out a preliminary review of the calculations made by the AER on removing the movement in provisions from the actual capital expenditure incurred. We have some concerns on the validity of the AER's calculations but in the limited time available to prepare this revised proposal, we have not had the opportunity to detail these concerns. We intend to make a submission on this issue following the lodgment of this revised proposal.

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

The AER did not accept Essential Energy's proposed forecast capital expenditure for the 2014-19 regulatory period, and instead substituted an amount of $1,885 million ($2013-14). As outlined in Chapter 6 we have considered the revisions necessary to incorporate the AER's draft decision on forecast capital expenditure for standard control services, but in the main have rejected the AER's draft decision. Table 5-7 sets out our revised forecast capital expenditure.

Table 5-7: Forecast capital expenditure relating to the provision of standard control services[122] ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Capital expenditure	522	527	518	493	471	2,531

Note: Capital expenditure includes equity raising costs and is net of disposals and capital contributions. Numbers may not add due to rounding.

[122] Capital expenditure is net of disposals and includes equity raising costs.

Allowed rate of return

The AER did not accept our proposed allowed rate of return and the parameters that made up this rate. As outlined in Chapter 8, we considered whether there were any revisions necessary to incorporate the AER's decisions. We also considered whether any revisions were necessary to incorporate the most current data. We have rejected the AER's draft decision. Table 5-8 sets out our revised rate of return, incorporating the most current data available.

Table 5-8: Proposed rate of return

Rate of return parameters	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%

Return of capital (Regulatory depreciation)

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

We have revised our proposed regulatory allowance for return of capital based on revisions we have made to our initial proposal for forecast capital expenditure and the opening value of the RAB.

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. One indicator of remaining asset lives is that used for accounting purposes. For depreciable assets as at 1 July 2014 Essential Energy has a weighted average remaining life of approximately 33 years according to the AER's approach, but an actual weighted average remaining life for accounting purposes of approximately 22 years.

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

We engaged Advisian to review both standard and remaining asset lives. Advisian's report is at Attachment 5.3 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.

The Advisian report highlights that Essential Energy claims regulatory depreciation over a substantially longer period and will also recover their existing RABs 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 business 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.

- 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 charges 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 charges 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, Essential 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 5.3 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.

Operating and tax costs

The AER rejected our proposed forecast operating expenditure and cost of corporate income tax for the 2014-19 regulatory period. We do not accept the AER's decision. Our detailed response to the AER's decision is set out in Chapters 7 and 8 respectively. As set out in the sections below, we have also made revisions to our proposed operating expenditure.

Forecast operating expenditure

… the operating expenditure allowance contained in the AER's draft determination is unrealistic and insufficient…

The AER did not accept Essential Energy's proposed forecast operating expenditure for the 2014-19 regulatory period, and instead substituted an amount of $1,440 million ($2013-14) based on the deterministic use of unreliable, untested and unsafe benchmarking. As detailed in Chapter 7 we have considered the revisions that the AER determined in its draft decision on forecast operating expenditure for standard control services, however the operating expenditure allowance contained in the AER's draft determination is unrealistic as it is insufficient to cover the costs of maintaining Essential Energy's safe and reliable network. Table 5-9 below sets out our revised forecast operating expenditure.

Table 5-9: Forecast operating expenditure relating to the provision of standard control services[123] ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Operating expenditure	498	491	455	459	428	2,331

Note: Totals may not add due to rounding

[123] Includes debt raising costs and DMIA.

Corporate income tax

The AER also rejected our proposed cost of corporate income tax. This was mainly due to the AER's decision to reject Essential Energy's proposed opening value of the tax asset base (TAB) and proposed value of imputation credits. As noted above we do not accept the AER's decision on the opening TAB. We have therefore not revised our calculation of the costs of corporate income tax for the 2014-19 regulatory period to include this revised value.

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 0.4. We do not accept the AER's decision on the value of imputation credits and consequently have not revised our estimate of corporate tax to incorporate the AER's decision. Chapter 8 of our proposal sets out our detailed reasons why we consider the AER should have accepted our proposed value of imputation credits.

The AER's substituted estimate of corporate income tax was also the consequence of the AER's decision on other areas of the building block proposal such as forecast capital expenditure and allowed rate of return. Our responses to these other decisions are detailed in chapter 7 and chapter 8 respectively of this revised proposal. Essential 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 5-10.

Table 5-10: Forecast cost of tax relating to the provision of standard control services ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Cost of corporate income tax	66	58	68	90	85	367

Note: Totals may not add due to rounding.

Shared asset reduction

The Rules require that the AER allow Essential Energy to include revenue increments or decrements that relate to the operation of incentives in the 2009-14 regulatory 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, in the provision of 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 decision to see if the materiality threshold is impacted by revisions we have made to our annual revenue requirements. Our calculation is set out in Table 5-11. Based on this calculation we have not revised our proposal.

Table 5-11: Materiality of shared asset use ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Forecast unregulated revenue from shared asset	1	2	2	2	2	9
Smoothed revenue (prior to shared asset reduction)	1,292	1,333	1,366	1,400	1,447	6,837
Materiality percentage	0.08%	0.15%	0.15%	0.14%	0.14%	0.13%

EBSS carryover amount from operation of scheme in 2009-14

The AER has not accepted Essential Energy's calculation of the carryover revenue from the application of the EBSS in the 2009-14 regulatory period. The AER substituted Essential Energy's calculated carryover amount with an amount of zero. 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 Essential Energy for the 2009-14 regulatory period.

- The AER's contention that provisions are not costs and hence should be excluded from the calculation.
- 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 operating expenditure only and not the forecast operating expenditure.

Consequently, we have not incorporated the AER's substituted amount in our revised annual revenue requirement. As indicated below, the AER stated that it would not apply the EBSS carryover penalty from the 2009-14 regulatory period:

> *Our draft decision is not to apply an EBSS carryover penalty to Essential Energy from the 2009-14 regulatory control period. The EBSS was intended to work in conjunction with a revealed cost forecast approach. Given how we are forecasting Essential Energy's opex for the 2014-19 period, we consider it would not be consistent with the intended operation of the EBSS, and it would not implement the EBSS in accordance with the terms of the NER, if we were to carryover the EBSS penalty.*
>
> *As it is uncertain whether we will rely on Essential Energy's revealed costs in the 2014-19 period in forecasting Essential Energy's efficient opex in the future, our draft decision is that no expenditure will be subject to the EBSS during the 2015-19 regulatory control period.* [124]

If the AER decides to not accept our operating expenditure proposal for the 2014-19 regulatory period and instead substitutes a lower amount, then we agree that any EBSS carryover penalty from the 2009-14 regulatory period should not apply.

Compliance with the AER's determined scheme

The AER decided to apply the EBSS guideline released in February 2008 (2008 EBSS) to Essential Energy for the 2009-14 regulatory period with the resulting financial results from the application of this scheme having effect in the 2014-19 regulatory period. The applicable EBSS guideline allowed for the exclusion of certain operating expenditure categories from the application of the scheme.

In deciding how the 2008 EBSS should apply to Essential Energy, the AER decided to exclude the DMIA, debt raising costs, 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 Essential Energy when applying the 2008 EBSS.

Specifically the AER determined a total operating expenditure allowance for Essential Energy of $2,052 million ($2008-09) from which the AER excluded $170 million ($2008-09) to arrive at a total forecast operating expenditure of $1,882 million ($2008-09) as the total forecast operating expenditure 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 regulatory 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.*[125]

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

Throughout the 2009-14 regulatory period Essential Energy submitted the actual operating expenditure to be used in applying the 2008 EBSS in the annual regulatory accounts or Regulatory Information Notices (RIN). The format of this RIN is specified by the AER and in relation to the information on EBSS operating expenditure, the AER required Essential Energy to report the actual operating expenditure incurred for each of the cost categories the

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[124] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19- Attachment 6*: *Capital Expenditure,* November 2014, p19-20.

[125] AER, *Final decision - New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, p250.

AER excluded from the operation of the EBSS in its final determination. Essential Energy complied with this request and clearly identified the actual operating expenditure for each year of the 2009-14 regulatory period that was subject to the operation of the EBSS.

We used these actual operating expenditure 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 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.*[126]

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 AER's draft decision to exclude movements in provisions contravenes its 2009-14 determination and applicable guideline.

Movement in provisions

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

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

The timing of cash outlays to satisfy these salaries and entitlements that Essential 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. Essential Energy has 'consumed' the service provided by that person at the time the person provided the service (e.g. fixes damage on the network) and the total cost to Essential Energy of 'consuming' that service is the salary and leave 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 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 Essential Energy has incurred in providing network services and that are called upon when the person takes leave, which could be many months after the time that the service for which the costs were incurred was performed. It is a fallacy to assert that movements in provisions are not actual costs incurred in delivering network services.

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

By endorsing this approach, the AER can be seen 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 Essential Energy's, be reflected in provisions in the AER's financial accounts).

[126] AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008, p5.

Essential 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 5.2.

Consistency with forecast operating expenditure

The AER also asserted that its 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 operating expenditure accurately reflects the costs faced by the DNSP in the regulatory control period.*[127]

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

Now the AER has proposed in its draft decision to retrospectively change the operation of the scheme by excluding movements in provisions from the actual costs, as it contends that they are not actual costs. To be consistent with its own guidelines, the AER would also have to adjust the forecast operating expenditure 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 carryover, perhaps a more significant issue is the impact on incentives arising from the AER's retrospective adjustment to the EBSS as it applies to Essential Energy.

> *…a more significant issue is the impact on incentives arising from the AER's retrospective adjustment to the EBSS as it applies to Essential Energy.*

We are not aware of any rule that explicitly provides the AER discretion 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*

[127] AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008, p6.

(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 future 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 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.

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.

As such, Essential Energy has not revised its proposal to incorporate the AER's decision or reasons for that decision on EBSS carryover amounts. Table 5-12 shows the EBSS revenue decrement from the application of the AER's approved scheme. We have provided the calculation of the EBSS carryover amounts in Attachment 5.4.

Table 5-12: Forecast EBSS carryover amounts ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
EBSS carryover amount	(15)	(50)	(45)	35	-	(74)

Note: Totals may not add due to rounding.

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

In our initial proposal, we used the sum of the building blocks to derive Essential Energy's unsmoothed total proposed annual revenue requirements. We also proposed the adjustment to the annual revenue requirements 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 charges.

Proposed revenue requirements and X-factors

The AER's decision on the unsmoothed annual revenue requirements, smoothed revenue and X-factors were based on decisions on other elements of the building blocks, which we have revised.

Table 5-13 sets out our revised unsmoothed and smoothed annual revenue requirements.

Table 5-13: Unsmoothed and smoothed annual revenue requirements ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Unsmoothed revenue	1,315	1,276	1,320	1,478	1,458	6,846
Smoothed revenue	1,292	1,333	1,366	1,400	1,447	6,837

We have made the following revisions to our initial proposal:

> Our unsmoothed revenue is 0.3 per cent higher than the initial proposal. These largely reflect consequential amendments we have made as a result of revisions to our building block components.

- The changes to the smoothed revenue reflect consequential amendments to incorporate the revisions to unsmoothed revenue. 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. This is set out in Table 5-14.

Table 5-14: Proposed X-factors (%, real)

	2014-15	2015-16	2016-17	2017-18	2018-19
X-factors	10.28%	-0.65%	-0.01%	0.01%	-0.82%

These main elements are inputs into the annual revenue requirement using the AER's PTRM. The complete PTRM is provided at Attachment 5.5.

Transitional year adjustment

In its decision, the AER's transitional year adjustment 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 decision.

As a consequence we consider that our revised unsmoothed revenue should be used as the value for the transitional year adjustment.

Indicative charges

The Rules required that our initial proposal set out indicative prices for each year of the 2014-19 regulatory period. The AER is not required to make a constituent decision on this element of our proposal. However, we have sought to demonstrate how our revisions have impacted charges, particularly in light of the AER's transitional determination.

The revisions reflect changes in our smoothed revenue, identified above. It also reflects changes in our energy forecast, which has a consequential impact on charges to customers. Our revised energy forecast is based on the latest econometric data, actual consumption, solar take-up and other demographic factors such as housing rates as detailed in Attachment 5.6. Our revised energy forecast represents a 1.8 per cent increase in energy over the five years compared to our initial proposal. This is set out in Table 5-15 .We note under a revenue cap determination that if consumption rises above this forecast network charges will reduce and if consumption falls below the forecasts network charges will increase.

Our revised energy forecast is based on the latest econometric data, actual consumption, solar take-up and other demographic factors such as housing rates… represents an 1.8 per cent increase in energy over the five years compared to our initial proposal.

Table 5-15: Forecast energy consumption (GWh)

	2014-15	2015-16	2016-17	2017-18	2018-19
Energy Consumption	11,991	11,939	11,811	11,696	11,678

As a result of these changes we have updated information we to that provided in our initial proposal on how average charges could move over the 2014-19 regulatory period. Table 5-16 outlines indicative changes in average annual distribution charges for the 2014-19 regulatory period based on our proposed revenue and our latest forecast of energy volumes.

Table 5-16: Change in average distribution charges based on latest energy forecasts (% change in real charges)

	2014-15	2015-16	2016-17	2017-18	2018-19
Average change in distribution charges (real)	-1.89%	-1.89%	-1.89%	-1.89%	-1.89%

The charges outlined above are indicative only and will be updated in our pricing proposal for 2015-16, to reflect:

> Updated energy consumption forecasts

> Any changes in the relative portion of revenues recovered from each tariff and tariff component.

We also note that the charges outlined above are only a portion of the total network use of system (NUOS) charge to customers. NUOS charges include the cost of the services provided by the NSW Transmission Network Service Provider (TransGrid) as well as the recovery of an amount to satisfy obligations under the NSW Climate Change Fund (CCF) and the Queensland Solar Scheme (QSS). These components are outside our control.

Pass-through events

The pass through mechanism in the NER recognises that a DNSP can be exposed to risks beyond its control, and 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 five pass through events including an insurance cap event, natural disaster event, terrorism event, insurer's credit risk event and an aviation hazards event. The AER's draft decision determined:

> Not to accept the insurer's credit risk event or the aviation hazards event

> To change the definition of the natural disaster, terrorism and insurance cap events.

Essential 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 assessment of 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.

> Does not agree with the AER's assessment of aviation hazards 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.

Essential Energy is particularly concerned with the AER's draft decision on aviation hazards event. In the recent decision in *South West Helicopters and anor v Essential Energy,* the Court found that the fire prone status of land can comprise the basis on which Essential Energy is taken to have known that low flying is 'likely'. This finding appears to expand (that is, expand beyond the previous decision in Sheather, for example because Essential Energy's knowledge is *inferred* from the fire prone status of the land) the circumstances in which Essential Energy could face liability issues for wire strikes. The decision may also significantly expand the scope of liability issues because a significant amount of land in NSW (and therefore, Essential Energy's network) is designated as fire prone. Given this and in order to demonstrate to insurers that there is or will be reasonable action to mitigate this risk, Essential Energy must consider what action is reasonable and appropriate to avoid or minimise the impact of further claims.

Attachment 5.7 discusses the AER's draft decision and provides the rationale for Essential Energy's revised proposal on pass through events.

6. CAPITAL EXPENDITURE

- Essential Energy considers the AER's proposed capital expenditure cannot adequately service customers or enable a safe and reliable network to be maintained.
- We believe our initial proposal was sustainable and prudent and required closer examination by AER to recognise the merits of what was originally proposed.
- The AER's benchmarking report is fundamentally flawed, lacks rigour and fails to enable appropriate engagement with the DNSPs.
- The AER's draft determination proposes a short term gain in lower charges at the expense of longer term affordability and service benefits for customers and network sustainability.
- The draft determination forms an inaccurate view of Essential Energy's considered approach to risk.

Summary

Our revised proposed capital program of $2,531 million 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 response to the AER's draft determination

Our forecast capital expenditure in the initial proposal was 43 per cent lower than allowed capital expenditure for 2009-14.[128] In our initial proposal, we provided the AER with information to demonstrate the efficiency and sustainability of our forecast capital expenditure. The lower capital expenditure reflected strategic realignment of objectives under the network reform program, a greater focus on minimising charges for our customers and observed reductions in the rate of growth in peak demand.

In its draft decision, the AER has rejected our proposed capital expenditure and substituted an amount of $1,885 million, or a reduction of 27 per cent from Essential Energy's initial proposal. We consider that the numbers analysed and substituted by the AER contain errors which have resulted in incorrect and inappropriate findings and decisions.

In our response, we draw the AER's attention to the significant amount of evidence we submitted in our initial proposal which the AER has not adequately considered, and we provide additional information in response to the matters raised. We also show that the AER has relied on high level analysis that does not account for our network size, design and characteristics and provide detailed analysis that illustrates the inappropriate and unsustainable network outcomes of the AER's draft decision.

Essential Energy considers the AER's substitute capital expenditure is detrimental to the long term interests of customers and is insufficient to maintain a safe and reliable network for the 2014-19 regulatory period and beyond. The marginal reductions in charges delivered by a further reduced capital program will be outweighed by the need for future increases in capital expenditure to correct the period of under investment in the network. Our response to the AER's draft decision is set out in this Chapter and supporting attachments.

[128] In real $2013-14 terms.

Revisions to our capital expenditure forecasts

Our revised proposal for standard control services capital expenditure for the 2014-19 regulatory period is $2,531 million as shown in Table 6-1. The changes include a review of our proposed program based on the latest available information such as network condition and demand forecasts, errors made in AER calculations and reviews requested by the AER such as probabilistic assessment based on the latest value of customer reliability (VCR) values. We consider these updates address matters that the AER had raised in its reasons for the draft decision. Our revised proposal is set out in the sections below.

…changes [in our revised proposal] include a review of our proposed program…errors made in AER calculations and reviews requested by the AER...

Table 6-1: Forecast standard control services capital expenditure 2014-15 to 2018-19 ($million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Initial proposal	542	511	518	505	499	2,574
AER draft determination	418	377	377	360	353	1,885
Revised proposal	522	527	518	493	471	2,531

Note: Capital expenditure includes equity raising costs and is net of disposals and capital contributions. Numbers may not add due to rounding.

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 capital expenditure 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 and forecast operating expenditure that Essential Energy sets out in its building block proposal for standard control services. To enable the AER to make its constituent decision, Essential Energy's building block proposal must include the total forecast capital expenditure and forecast operating expenditure for the relevant regulatory period which the DNSP considers is required in order to achieve the capital and operating expenditure objectives.

Framework for AER's decision on capital expenditure

The Rules require the AER to make a number of constituent decisions as part of its distribution determination. Clauses 6.12.3 and 6.12.4 relate to the AER's decisions on the forecast capital expenditure and forecast operating expenditure proposed by a DNSP in its building block proposal. The AER either:

> *(i) acting in accordance with clauses 6.5.6(c) and 6.5.7(c), accepts the total of the forecast operating expenditure and capital expenditure 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) and 6.5.7(d), does not accept the total of the forecast operating expenditure and capital expenditure 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 operating expenditure and capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital and operating expenditure criteria, taking into account the capital and operating expenditure factors*

In making its decision, the AER is guided by the objectives, criteria and factors in the Rules. These should be interpreted having regard to 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.

Objectives, criteria and factors

The Rules set out a framework such that Essential Energy is required to propose total capital expenditure that Essential 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 Essential Energy to include in its building block proposal the total forecast operating expenditure and capital expenditure for the 2014-19 regulatory period which Essential Energy considers is required to achieve each of the expenditure objectives.[129]

The AER is required to make a decision on the total forecast capital expenditure proposed by Essential Energy. The Rules provide that the AER must accept the forecast expenditure included in Essential Energy's building block proposal if the AER is satisfied that the total forecast capital expenditure 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 Essential Energy's proposed total forecast capital expenditure reasonably reflects each of the expenditure criteria, the AER must have regard to the capital expenditure factors.[130] The purpose of the specific capital expenditure 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 capital expenditure. 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*

[129] 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.

[130] 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.

b) *the reliability, safety and security of the national electricity system.*

Therefore, the overall objective of the Rules governing the AER's decision is to ensure that the forecast expenditure is set to achieve a reliable, secure and safe supply of standard control services at an efficient cost in the long term.

…the overall objective of the Rules governing the AER's decision is to ensure that the forecast expenditure is set to achieve a reliable, secure and safe supply of standard control services at an efficient cost in the long term.

Changes to the NER in 2012

As part of the 2012 Rule change on the Economic Regulation of NSPs, the AEMC reviewed the decision making framework for capital expenditure. The AEMC largely maintained the existing framework in the Rules that was applied to making our 2009-14 determination. This included maintaining the structure of the objectives, criteria and factors.

At the time, the AEMC 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:[131]

> The assessment process must start with a DNSP's proposal - The proposal is necessarily the procedural starting point for the AER to determine a capital expenditure or operating expenditure 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.

The proposal is necessarily the procedural starting point for the AER to determine a capital expenditure or operating expenditure allowance.

> 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 is required to be taken into account.

> Consider the probative value of material presented - 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 in regard to any other submission of probative value.

> The AER's assessment techniques in making its analysis are not limited – The NSP'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 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 capital expenditure or operating expenditure. The AER, whenever it determines a substitute for

[131] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012.

a NSP's proposal, is not constrained by the capital expenditure and operating expenditure 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 NSPs, 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 on the approach the AER utilises in assessing a DNSP's forecast expenditure. Ultimately, this guideline should support the achievement of the capital expenditure objectives and criteria and align to the capital expenditure factors. During the AER's development of the guideline Essential Energy, and the NSW DNSPs, noted their concerns with the proposed guideline:

During the AER's development of the guideline Essential 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.* [132],[133]

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 a DNSP to inform the AER of the forecasting method it proposes to use to prepare the expenditure forecasts that form part of its regulatory proposal. This submission must occur six months prior to the submission of a DNSPs regulatory proposal. We consider this is to provide the AER with further clarity as to the forecasting method 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.

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.

Interdependency of the framework

As outlined above, the framework contains a number of elements that provide guidance and direction to DNSPs and the AER. We consider the 2012 rule change did, in some way, reduce the necessity or obligation on the AER to assess the material provided at a granular level to the extent that the AEMC clarified the intent of the framework.

[132] NSW DNSPs, *Submission on AER expenditure forecast assessment guidelines issues paper*, 14 March 2013.
[133] NSW DNSPs, *Joint Submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013.

In doing so, the AEMC did however introduce a valuable and necessary cross check in the determination process. This was to ensure that when aggregated, the sum of the detailed decisions and assessments made by the AER also delivered an overall outcome that is logical and reasonable in the circumstances. Clearly the reverse also applies such that a decision that appears erroneous overall should result in further detailed analysis.

…[a necessary cross check] was to ensure that when aggregated, the sum of the detailed decisions and assessments made by the AER also delivered an overall outcome that is logical and reasonable in the circumstances.

The amendments did not provide a criterion to assess whether an overall revenue allowance achieves the NEO. We consider this is because the guidance for this already exists within the decision making framework provided in the NER. The change is to avoid the occurrence of sub-optimal decisions being made when combining accurate and sound decisions at the granular level.

As such, these amendments to the NER and NEL do not permit the AER to make a decision solely at the higher level, that is the total revenue and the associated expenditure plans. The overall assessment and detailed assessment are complimentary and therefore flawed in the absence of one another. That is to say, it cannot be concluded that a decision achieves the NEO at the overall level without reference to the methodological analysis and application of the expenditure factors.

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 capital expenditure. We provided significant evidence demonstrating the efficiency of our proposed capital program and our responses to changing conditions. The 2014-19 regulatory period proposed capital expenditure was designed to maintain the necessary improvements made in the 2009-14 regulatory period and meet and manage expected pockets of spatial demand growth.

At the time of the 2009-14 determination, the AER scrutinised our proposed capital expenditure in great detail, assessing our capital expenditure categories and our investment need. The AER made minor reductions to our proposed capital expenditure based on its thorough assessment, accepting the need for increased investment in full knowledge of the associated increases in network charges.

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.

In delivering the program…we have improved reliability, increased security of supply, and replaced deteriorated assets that posed safety risks to our customers and workforce…[and focused on delivering] targeted efficiencies to the capital program.

Our customer research indicated that customers did not want lower charges in return for reduced service levels. A central aspect of our proposal was to show how the proposed capital expenditure 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, and drive ongoing efficiency and affordability for our customers.

Our customer research indicated that customers did not want lower charges in return for reduced service levels.

Our proposed program of $2,574 million addressed customer concerns as it:

> Was 43 per cent lower than the efficient allowance for the 2009-14 regulatory period

> Contributed to delivering a charging path at or below CPI

- Sought to meet and manage customer growth and expected demand
- Sought to meet our obligations safely, including maintaining current levels of service and security of supply
- Represented a sustainable level of investment for future regulatory periods.

Achieving the capital expenditure objectives

Essential Energy included in the building block proposal a total forecast capital expenditure for the 2014-19 regulatory period that Essential Energy considered necessary to carry out activities to achieve each of the capital expenditure objectives listed in clause 6.5.7(a) of the Rules. This total forecast capital expenditure comprises 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 capital expenditure objectives.

We outlined the components of our proposed total forecast capital expenditure for the 2014-19 regulatory 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 Essential Energy needs to undertake and specify the capabilities, systems and personnel that Essential Energy needs to have. Consequentially, achieving the expenditure objectives gives rise to expenditure which is either of a capital or operating nature.

Table 6-2 provides a summary of the drivers of investment for each of our capital plans, and how these relate to one or more capital expenditure objectives. We note that more detailed information on our forecast methods and programs can be found in our capital expenditure chapter and supporting attachments and information in our initial proposal.

Table 6-2: Capital plan drivers and objectives achieved

Capital plan	Capital expenditure objectives achieved
Regional Planning Reports	1
Asset management plans	All
Distribution network growth strategy	1 and 3
Reliability and quality of supply strategic plans	2
Demand management strategic plan	All
Non-system asset plans	All

Regional planning reports

Essential Energy’s regional planning reports identify major sub-transmission projects, which may include the augmentation of existing assets or the construction of new assets. The plans encompass forward projections of peak demand and customer growth, and they identify the assets on the network that are projected to exceed their limits, and the sub-transmission and distribution network development projects required to address this. This aspect of planning also incorporates Essential Energy's demand side management activities aimed at containing or reducing the customer load presented to the network, and also involves specific developments to maintain security of supply. A bottom up approach is adopted, with each constraint separately assessed and an individual project report developed.

The regional planning reports cover the investment in capacity on the sub-transmission network. As such the plans achieve the following capital expenditure objective:

- Objective 1 – Decisions to increase capacity of the sub-transmission network are related to peak demand arising from new connections and increased growth from existing customers.

We note that the removal of Schedule 1 of our licence conditions means that we no longer have to meet specific security criteria. In our forecast capital expenditure, we have prudently given consideration to opportunities to defer investment as a result of the removal of Schedule 1 of our NSW Design, Reliability and Planning licence. This means that while we will for the most part maintain our previous performance, there will be instances where our forecast capital expenditure will result in a notional decline in security standards.

In our forecast capital expenditure, we have prudently given consideration to opportunities to defer investment…

Asset management plans

These plans are based on the management of an asset group and identify expenditure on all distribution network assets and sub-transmission assets. The Asset Management Plans (AMPs) are strategic business plans used to manage network assets and deliver service levels to meet stakeholder requirements. Essential Energy has developed 14 AMPs which cover all of Essential Energy's network assets. Each AMP defines the life cycle of a specific group of assets and covers the major drivers of expenditure. The groupings have been chosen to ensure that synergies between assets can be maintained, and to allow the best mix between operating expenditure and capital expenditure.

Essential Energy has developed 14 AMPs…to ensure that synergies between assets can be maintained, and to allow the best mix between operating expenditure and capital expenditure.

Each AMP defines the service levels applicable to the asset group based on legislative and stakeholder requirements, and then compares asset capability and current performance to determine if there is a gap. Targets are defined based on the asset capability and service gap and strategies are developed to achieve the targets.

These AMPs are supported by a set of strategic plans, planning reports and individual investment cases. The planning process produces an annual capital expenditure program and sets priorities for capacity augmentation, and supply security, quality and reliability over the investment horizon to 2018-19. As such the plans achieve the following capital expenditure objectives:

- Objective 1 – Decisions to increase capacity of the sub-transmission network are related to peak demand arising from new connections and increased growth from existing customers.
- Objective 2 – Decisions to replace assets on the distribution and sub-transmission network are related to our underlying regulatory obligations to provide a safe network.
- Objective 3 – Decisions to replace and increase capacity are designed at maintaining the reliability, security and quality of supply and through the network conditions.
- Objective 4 – Decisions to replace assets on the distribution and sub-transmission network are related to maintaining our safety standards based on previous performance.

Distribution Growth Strategy

This plan identifies forecast capital expenditure for augmentations on the distribution network. This includes 'customer connection' capital expenditure to augment the shared network to enable connection of a customer. It also includes reinforcement of the low voltage network to meet a combined increase in localised demand from existing and new customers. Distribution growth is not a simple extrapolation of global demand forecasting. The sheer scale of Essential Energy's network coverage results in a collection of extremes to be serviced - rural versus urban centres, a multiplicity of communities and industry, population migration to coastal areas, and climatic extremes from inland to coastal, snowfields to sub-tropical forests. This range of extremes turns global averages into statistics that are not useful at the required micro level of decision making.

The sheer scale of Essential Energy's network coverage results in a collection of extremes to be serviced - rural versus urban centres, a multiplicity of communities and industry, population migration to coastal areas, and climatic extremes from inland to coastal, snowfields to sub-tropical forests. This range of extremes turns global averages into statistics that are not useful at the required micro level of decision making.

Historical load growth resulting from factors including uptake in air conditioning and modern appliances, is complicated by the reduction in power quality tolerance, caused by the advent of electronics and integration of microprocessors within appliances. Most of the expansion in demand has imposed added burden on 40 to 50 year old assets that were designed and constructed in a period far removed from the standard of living and customer expectations present today. For this plan the underlying driver of investment is growth. As such, we consider the plans achieve the following capital expenditure objectives:

- Objective 1 – Decisions to increase capacity of the sub-transmission network are related to peak demand arising from new connections and increased growth from existing customers.
- Objective 3 – Decisions to replace and increase capacity are designed at maintaining the reliability, security and quality of supply and through the network conditions.

Reliability and quality of supply strategic plans

This plan identifies any additional capital expenditure specifically required to meet reliability performance standards in the NSW Design, Reliability and Planning licence conditions (schedules 2 and 3) and customer expectations. For this plan the underlying drivers of investment are reliability compliance and growth, and therefore ostensibly meet objective 2 – Investing in reliability are to meet Schedule 2 and Schedule 3 of our NSW Design, Reliability and Planning licence conditions. These relate to average performance standards and minimum standards for feeders respectively.

Demand management strategic plan

This expenditure is required to manage the demand on our network through various non-network alternatives. The decision to apply demand management or to augment the network remains an issue of:

- Economic efficiency
- Technical feasibility
- Timing
- Service preferences
- Application of sound industry commercial practice
- Determination of the optimum means of providing supply capacity to customers.

Performing analysis and consultation around all of these areas to ensure a balanced outcome to the business and our customers in terms of the provision of a safe, efficient and reliable electricity supply is a significant and ongoing process.

A distribution annual planning report (DAPR) is prepared and published by Essential Energy. This document provides historical and forecast peak load data and capacity information for all zone substations, and discloses where a network constraint is forecast to occur within five years. The information allows customers and energy service providers to consider whether they may be able to assist in addressing a network constraint through the implementation of demand management initiatives. This approach actively seeks to minimise barriers and disincentives to the adoption of demand management options.

Non-system asset plans

The corporate property plan includes capital expenditure to support the housing of staff. 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 staff in office and depot accommodation such that they can perform their network activities in a safe and efficient manner. In this respect, our forecast capital expenditure is to achieve all the capital expenditure objectives as a whole, given that they are essential to performing our network activities.

The underlying driver of investment [in non-system assets] is to support the network...our forecast capital expenditure is set to achieve all the capital expenditure objectives as a whole, given that they are essential to performing our network activities.

The fleet and other support plans identify vehicles and equipment used to provide our network services, and other capital expenditure such as plant and equipment. Fleet is used to transport staff to undertake capital works (for example pool cars) or directly used to build assets (such as elevated work platforms). Plant and equipment are used directly by our staff in network activities such as maintenance and construction. In this respect, our forecast capital expenditure is to achieve all the capital expenditure objectives as a whole, given that they are essential to performing our network activities.

The information technology (IT) plan Identifies infrastructure, platforms, applications and devices required to support our network and corporate functions. Technology provides a necessary supporting activity to enable us to meet our network objectives and to fulfil our corporate obligations. Non-system IT assets provide operational support to our staff to perform building activities required to achieve the capital expenditure objectives.

In this respect, our forecast capital expenditure is set to achieve all the capital expenditure objectives as a whole, given that they are essential to performing our network activities.

We have applied our proposed connection policy to identify the forecast capital expenditure that relates to standard control services, in contrast to capital expenditure that customers directly fund. Our proposed connection policy is set out in Attachment 6.1. This connection policy has some minor corrections from that lodged with the initial proposal.

Satisfying the capital expenditure criteria with regard to the capital expenditure factors

Our initial proposal was accompanied by expert economic opinion from NERA Consulting on how to interpret the capital expenditure criteria in the Rules, and on how to demonstrate that the forecast capital expenditure 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 capital expenditure factors that the AER must consider in deciding whether it is satisfied that the forecast expenditure reasonably reflects the expenditure criteria.

Methodology employed by Essential Energy to derive forecast capital expenditure

In our initial proposal we demonstrated that we have a comprehensive approach to forecasting our capital expenditure for the 2014-19 regulatory period.

Our forecasting process involves both top down and bottom up methods in developing our capital expenditure forecast. In our proposal we outlined our use of historic expenditure trend analysis, individual asset investment business case development, probabilistic load forecasting for planning and NNSW's portfolio prioritisation of the program. The bottom up methods examined the following issues 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
- 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 capital expenditure 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. This framework is discussed further in Attachment 6.2.

We have a prudent and robust process in place to ensure that our capital expenditure program represents a reasonable estimate of the lowest cost solution to address a genuine network need.

As part of this process the Board considered the risk based portfolio, including a number of projects and programs at selected constraint points, when determining an appropriate investment risk versus expenditure position. The Board was 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 capital expenditure category and its relevant underlying drivers are appropriately accounted for such that the resulting forecast capital expenditure is reflective of the efficient costs that a prudent operator would require to achieve the capital expenditure objectives. This process gave us confidence that our total forecast capital expenditure would reasonably reflect the capital expenditure criteria and ensures that the NEO and the Revenue and Pricing Principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient costs we expect to incur in the 2014-19 regulatory period.

Our initial proposal also identified the relevant operating expenditure factors that align to assessing the prudency of our 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 operating expenditure requirements. For instance we identified that reductions in replacement capital expenditure will degrade the health of assets on the network, and increase the efficient maintenance costs. We also considered how IT and property capital expenditure may impact operating expenditure for these activities.
- The extent to which Essential Energy has considered and made provision for efficient non network alternatives – We considered the extent to which demand management activities taken to defer capital expenditure would impact operating expenditure in the 2014-19 regulatory 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 customers as identified by the DNSP in the course of its customer engagement (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 capital expenditure meets the criteria.

Capital expenditure factor 5 states that the AER must have regard to the actual and expected capital expenditure of the DNSP during any preceding regulatory 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 initial proposal. We showed that we performed significantly better than the targets that the AER had determined were efficient, as can be seen in Figure 6-1.

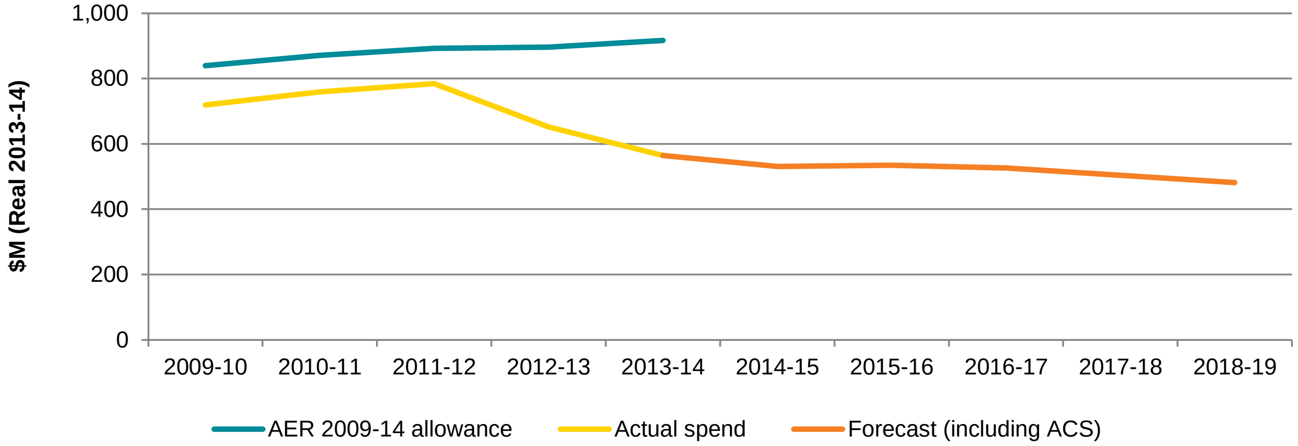

Figure 6-1: Total capital expenditure 2009-10 to 2018-19($million, 2013-14).

This performance was achieved by responding to changing conditions and implementation of a number of delivery efficiencies. It has set a solid platform for Essential Energy in ensuring that the forecast capital expenditure for the 2014-19 regulatory period reasonably reflects the efficient costs that a prudent operator would need to achieve the capital expenditure objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

Capital expenditure 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 expenditure that would be incurred by an efficient DNSP over the relevant regulatory 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 by the NER. This failure delayed the publication of the report by almost two months and resulted in no consultation or engagement with Essential Energy on how the AER would use the report to assess and determine forecast operating expenditure. This is unsatisfactory, and prejudicial to the interests of Essential Energy and inconsistent with the NER.

The AER did not release its first benchmarking report in September 2014 as required by the NER, and resulted in no consultation or engagement with Essential Energy on how the AER would use the report to assess and determine forecast operating expenditure. This is unsatisfactory, and prejudicial to the interests of Essential Energy and inconsistent with the NER… …benchmarking has inherent limitations such as the inability to conduct 'like for like' analysis across peer firms, data inconsistency

In Attachment 5.4 of our initial proposal, we submitted a comprehensive report on the limitations and role of benchmarking as a partial indicator. 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 a failure in meeting 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 DNSPs' proposal or as a basis to substitute the forecast, given its 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 capital expenditure 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.

AER's draft decision

The AER has rejected our proposed capital expenditure and determined a substitute capital expenditure allowance of $1,885 million. This program would not be efficient or sustainable and will result in increased operating expenditure, jeopardise the safety of customers, contractors and staff and place at risk the security and reliability of the network in the 2014-19 and subsequent regulatory periods.

*Table 6-3: Essential Energy Standard Control Capital expenditure (real $2013-14 million)**

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Initial proposal	542	511	518	505	499	2,574
AER Draft Decision	418	377	377	360	353	1,885
Difference	(124)	(134)	(141)	(144)	(145)	(689)
% change	-22.9%	-26.2%	-27.3%	-28.6%	-29.1%	-26.8%

* Capital expenditure includes equity raising costs and is net of disposals and capital contributions.

In making its assessment, the AER relied on data from the Reset RIN, rather than our initial proposal…[and] 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…

Table 6-3 shows the AER has made a 27 per cent reduction to our proposed program because it considers our overall capital expenditure program will not result in the lowest sustainable cost based on a top down assessment coupled with some bottom up analysis of volumes and costs by category driver.

In making its assessment, the AER relied on data from the Reset RIN, rather than our initial proposal, to assess the forecast capital expenditure by driver including 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:

> *First, Essential Energy's forecasting methodology applies a bottom-up build (or bottom-up assessment) to estimate the forecast expenditure for a significant portion of its capex categories. …………In particular, to derive an estimate of capex by solely applying a bottom-up assessment does not itself provide any evidence that the estimate is efficient.*
>
> *……….*

Second, Essential Energy's cost-benefit evaluation of each of its capital projects or programs reveals that its underlying risk assessment is overly conservative. This is evident in Essential Energy not fully justifying the timing and priority of its proposed forecast capex. Ultimately, this overly conservative approach to risk means that Essential Energy is forecasting more capex in the 2014–2019 period than is necessary to achieve the capex objectives.

………..

Finally, Essential Energy's forecast methodology lacks a clear delivery strategy or plan. [134]

The AER then assessed the proposed capital expenditure by driver to determine the reductions and substitute amounts at the category level. The AER purported to:

> Reject augmentation capital expenditure of $745 million and substitute a forecast amount of $475 million, a 36 per cent reduction

> Reject replacement capital expenditure of $856 million and substitute a forecast amount of $675 million, a reduction of 21 per cent

> Accept connections capital expenditure of $366.1 million

> Accept non-network capital expenditure of $306.4 million

> Reject capitalised overheads of $681.0 million and substitute a forecast amount $478.6 million, a reduction of 30 per cent

> Reject our labour cost escalators although further information is required before the AER can make a reduction to the capital expenditure forecast

> Accept capital contributions of $336.1 million.

These reductions were made in consideration of top down factors including:

> Benchmarking analysis

> Reducing demand

> 2009-14 regulatory period investment

> Network utilisation

> Amendments to licence conditions

> Risk management and governance framework

> Deliverability.

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 initial proposal and concluded that Essential Energy did not have a distinct cost advantage or disadvantage that invalidated the benchmarking analysis. This report can be found as part of Attachment 5.33 to Ausgrid's initial proposal.

These reductions also relied on top down assessment tools such as repex, augex (in part), project reviews and consultant advice. For the augmentation capital expenditure forecast, the AER relied on a report provided by WorleyParsons and for replacement capital expenditure the AER relied on a report provided by EMCa. The majority of the replacement capital expenditure was assessed using the repex model, with the programs reviewed on a case by case basis.

[134] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 6: Capital expenditure*, November 2014, p19-20.

In assessing Essential Energy's proposed capital program there were a number of issues that the AER were unable to form a view on at the time of the draft decision. The AER expect Essential Energy's revised proposal to contain:

> *In assessing Essential Energy's proposed capital program there were a number of issues that the AER were unable to form a view on at the time of the draft decision.*

- 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 operating expenditure escalation.
- Consideration of the latest VCR figure developed by AEMO in our project assessments.
- Latest demand forecasts and any associated revisions to the capital program.
- Clarification of the capital contributions proposed.
- Views on whether an explicit reduction to system capital expenditure is required to account for demand management activities.

Revisions to address the AER's draft decision

In response to the AER's 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 either revise or not revise our initial proposal in addressing the matters raised by the AER. Consistent with the NEO and the capital expenditure objectives, we have sought to develop a capital expenditure 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 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.

> *Consistent with the NEO and the capital expenditure objectives, we have sought to develop a capital expenditure forecast that is the efficient and prudent cost of maintaining a safe, reliable and secure supply of electricity.*
>
> *…we have not revised our proposal…[as we believe] the AER's draft decision is flawed for a number of reasons…*

For the most part, we have not revised our proposal in response to the AER's draft decision. 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 main reasons:

- The AER's decision contains substantive errors in the capital expenditure 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 capital expenditure categories is based on flawed analysis, unreasonable views and has 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 proposed $2,574 million ($2013-14) in our initial proposal, and in our revised proposal this program has been decreased by 1.7 per cent to $2,531 million ($2013-14). The key changes are shown in Figure 6-2 being:

- Updated real labour escalation – We have amended our proposed estimate of labour cost escalators to incorporate the AER's method, noting it will be updated in the final determination.
- LiDAR – We have increased augmentation capital expenditure to account for updated asset condition information resulting from our LiDAR program.

> Labour productivity.

> Updated VCR – We have decreased augmentation capital expenditure programs by applying the updated VCR values as suggested by the AER in its draft decision.

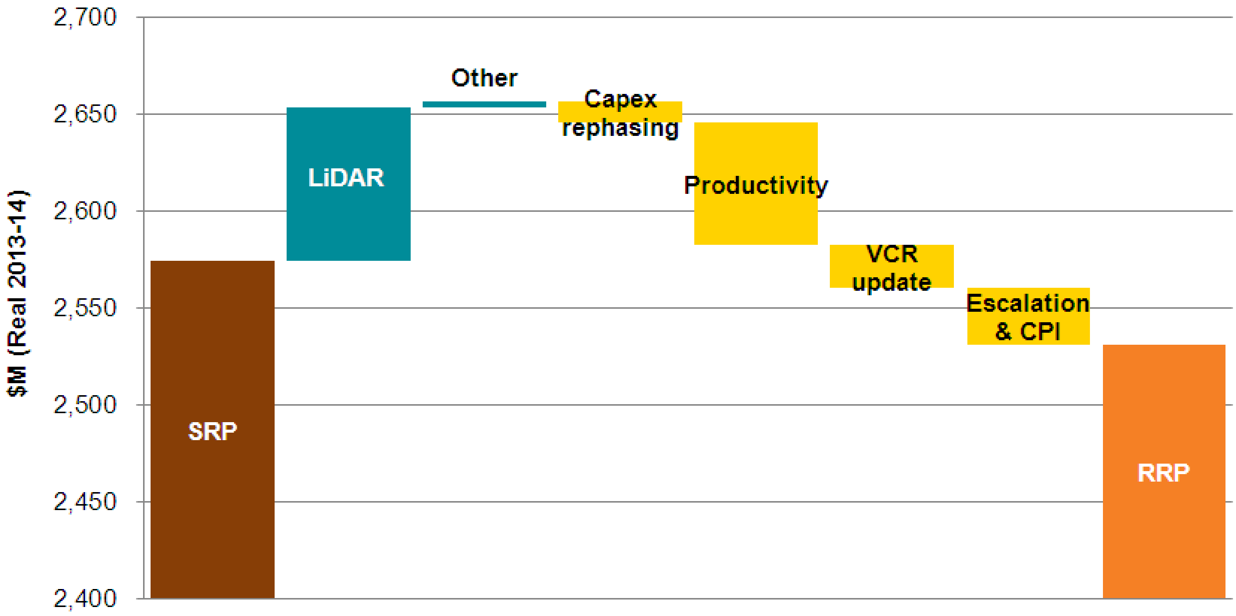

*Figure 6-2: Movement in capital expenditure from SRP to RRP**

* Capital expenditure includes equity raising costs and is net of disposals and capital contributions.

For comparative purposes, the revised capital program is contained in Table 6-4 by the categories proposed by Essential Energy in our initial proposal.

*Table 6-4: Revised forecast capital expenditure over the 2014-19 regulatory period ($2103-14 millions)**

	2014-15	2015-15	2016-17	2017-18	2018-19	Total
Growth	178	161	148	140	130	756
Asset renewal/replacement	205	212	219	216	215	1,068
Reliability and quality of service enhancement	27	31	31	31	32	154
Compliance	36	72	68	62	56	294
Non-system assets	73	51	52	44	38	257
Total network capital	**520**	**527**	**518**	**493**	**471**	**2,529**
Equity raising costs	3	-	-	-	-	3
Total Net capital expenditure	**522**	**527**	**518**	**493**	**471**	**2,531**

* Capital expenditure includes equity raising costs and is net of disposals and capital contributions.

Note: numbers may not add due to rounding.

Proposed capital expenditure and numerical errors

The purpose of this section is to identify the numerical basis for the AER's decision on capital expenditure, and to identify our concerns with the AER's decision as a result. Ultimately we seek to demonstrate that the AER's decision utilises incorrect proposed figures and as a result contains errors in both the assessment and substitute forecast.

… the AER's 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 initial proposal and provided data in the manner and form specified by the AER. Essential Energy's proposed capital expenditure was contained in the initial proposal and accompanying PTRM. The RIN data bears limited resemblance to the information we use for business as usual purposes as it is based on AER mandated definitions and instructions. Whilst the figures provided in the RIN reconcile at the total level to those included in Essential Energy's initial proposal (as required by the RIN) they do not form part of our substantive or revised proposal.

Our concerns with the RIN data were articulated in the basis of preparation which accompanied the RIN. We sought advice from PwC in regards to the appropriateness of the RIN data and basis of preparation. Further concerns relating to the RIN data and basis of preparation are outlined in the PwC report, provided at Attachment 6.3 which states:

> *Due to these issues, the structure and records of both financial and operational data was adjusted or reallocated by the distributors to fit the RIN requirements. Estimated information was provided in instances where information was not available or not recorded in the form required by the RIN*[135]*.*
>
> *and*
>
> *The Productivity Commission has highlighted the difficulty in distinguishing between inefficiency and errors arising from model misspecification, poor data, different regulatory settings and varying operating environment.*[136] *This is of particular relevance given the AER's reliance on benchmarking in these Draft Decisions to substitute alternative expenditure forecasts in place of the distributors' proposals.*[137]

Additionally, from a procedural perspective we consider our proposed capital expenditure in the initial proposal should form the starting point and basis of the AER's assessment.

The AER has sought to assess the forecast capital expenditure on direct cost basis, exclusive of overheads although occasionally gross figures are quoted by the AER.

In addition to this, a global adjustment factor and capitalised overheads rate of 32 per cent is applied to convert the AER's decision by RIN categories to the PTRM asset classes. This smearing is not consistent with the AER's own decision to accept our proposal for some categories, and simply applies a universal reduction to the categories that are the basis of the capital component of our revenue allowance. Our concerns with the adjustments applied to capitalised overheads are outlined in Attachment 6.4. It also ignores Essential Energy's AER approved CAM, provided at Attachment 6.5.

Assessment of replacement capital expenditure

In its draft determination the AER has rejected Essential Energy's proposed replacement capital expenditure forecast of $856 million ($2013-14) and substituted an amount $675 million ($2013-14) excluding overheads. The substituted amount appears in the main to be by the use of the AER repex model with little regard to the base build by Essential Energy.

The AER draft decision is intuitively incorrect and provides an unsustainable level of replacement capital expenditure. The Essential Energy replacement capital expenditure allowance is only four per cent greater than that provided for Endeavour Energy to replace assets on a network broadly five and a half times times longer, with poles on average ten years older and spread over a vastly greater geographic area. Further information on replacement capital expenditure can be found in the sections below and in Attachment 6.6.

[135] PwC, *NNSW Appropriateness of RIN data for Benchmarking B2*, 9 January 2015, p12.

[136] Productivity Commission, *Electricity Network Regulatory Frameworks, Report No. 62,* Canberra, 2013, p29.

[137] PwC, *NNSW Appropriateness of RIN data for Benchmarking B2*, 9 January 2015, p11.

Assessment of augmentation capital expenditure

In its draft determination the AER has rejected Essential Energy's proposed augmentation capital expenditure forecast of $745 million ($2013-14) and substituted an amount $475 million ($2013-14) excluding overheads. It should be noted that in the draft determination the AER reduced the expenditure on HV feeder augmentation capital expenditure by $151 million ($2013-14) based on their calculation of ratcheted demand. Essential Energy has identified that the AER has made an error when calculating Essential Energy's ratcheted demand. The AER excluded the forecast growth on several substations, due to an error in their spreadsheet. When these loads are included in the AER's spreadsheet the ratcheted demand changes from negative 35 per cent growth to positive 8 per cent growth. Therefore, we consider the reduction made to the proposed augmentation capital expenditure is overstated and in error based on the AER's own decisions.

> *…the AER has made an error when calculating Essential Energy's ratcheted demand.*
>
> *The AER excluded the forecast growth on several substations, due to an error in their spreadsheet.*
>
> *The AER provides no substantiation for a conclusion to apply a 20 per cent reduction [in replacement capital expenditure] which appears to be an arbitrarily determined result, especially given Endeavour Energy and Ausgrid both received an arbitrary 15 per cent reduction based on the same information.*

The other major area of the AER's reduction to augmentation capital expenditure is a global 20 per cent cut based on a recommended range of 10-20 per cent provided by consultant WorleyParsons in assessing Endeavour Energy's augmentation capital expenditure. The consultant report does not indicate that the reductions for Essential Energy would be in the order expected for Endeavour Energy. The AER provides no substantiation for a conclusion to apply a 20 per cent reduction which appears to be an arbitrarily determined result, especially given Endeavour Energy and Ausgrid both received an arbitrary 15 per cent reduction based on the same information.

Essential Energy has now carried out a risk based review and incorporated the changes to the VCR as requested by the AER in its draft decision, meaning the forecast augmentation capital expenditure is now based on more rigorous options analysis compared to the arbitrary 20 per cent reduction. The results of this analysis have been included in our revised proposal and results in a reduction to forecast capital expenditure compared to our initial proposal.

> *…[our analysis] results in a reduction to forecast capital expenditure compared to our initial proposal.*

The above issues relating to augmentation capital expenditure are discussed in further detail in Attachment 6.7.

At the time of preparing Essential Energy's initial proposal a NNSW initiative commenced to carry out a detailed inspection of the Essential Energy network to ensure it was safe and compliant with minimum height requirements and vegetation clearance requirements.

Recent case law involving Essential Energy (Courts v Essential Energy [2014 NSWSC 1483 October 2014) has highlighted the relevance of minimum height requirements to safety and liability issues. Mr Courts suffered injuries when he came into contact with an overhead conductor while unloading sheep from the back of a large truck. The judge in the case noted that the clearances reflected in industry standard documentation are for the "*purpose of eliminating the risk of contact by normal use of the ground under the line*" … [and] … "*constitute an assessment by electricity authorities … of what reasonable care requires*". This section of the judgement reflects recent judicial consideration of the relationship between minimum height requirements and the potential safety incidents. It would be expected that the same analysis would be applicable to incidents arising from vegetation clearance requirements.

The detailed Aerial Patrol and Analysis (AP&A) inspection using LiDAR based tools (Attachment 6.8) has identified that there are a significant number of priority defects that need to be addressed in association with the AP&A inspection. The financial implications associated with the identified tasks will require an additional augmentation capital expenditure investment of $77 million ($2013-14) over the five years of the determination. This

> *…detailed Aerial Patrol and Analysis (AP&A) inspection using LiDAR based tools has identified that there are a significant number of priority defects that need to be addressed…*

expenditure is required to address the height compliance requirements of Essential Energy's distribution network.

After reducing the augmentation capital expenditure forecast to allow for the risk based assessment incorporating the changes to the VCR and increasing the augmentation capital expenditure to meet the requirement of the AP&A program the total revised augmentation capital expenditure proposal for Essential Energy has increased by $59 million.

Assessment of connections capital expenditure figures

In its draft decision, the AER has accepted our initial proposal for connections capital expenditure, so no revisions are necessary.

Assessment of non-network capital expenditure figures

In its draft decision, the AER has accepted our initial proposal for non-network capital expenditure, so no revisions are necessary.

Assessment of capitalised overhead figures

In its draft determination the AER has rejected Essential Energy's proposed capitalised overheads forecast of $681 million ($2013-14) and substituted an amount of $479 million ($2013-14). The AER has separately assessed Essential's capitalised overheads and developed a substitute forecast based on a capped allocation rate of 32 per cent. It is unclear how this approach is consistent with the AER's approved CAM for Essential Energy; however this is discussed in more detail in later sections and in Attachment 6.4.

The 32 per cent cap was calculated by dividing the total capitalised overheads by the total standard control services gross capital expenditure (excluding overheads and non-network capital expenditure) for the 2009-14 regulatory period. Setting aside the legitimacy of such an approach, using a gross capital expenditure 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.

… the percentage cap developed by the AER is understated; meaning the resulting reduction to capitalised overheads is overstated.

In addition to this, in converting the draft decision into PTRM asset classes the AER has applied a direct system and direct non-system global percentage reduction and then applied 32 per cent of capitalised overheads. This smears the reduction across all asset classes thereby negating the AER's specific program cuts.

Assessment of capital contributions

In its draft decision, the AER has accepted our initial proposal for capital contributions, so no revisions are necessary.

Procedural issues with the AER's decision on capital expenditure

Procedural issues with the AER's decision on capital expenditure

The purpose of this section is to identify specific concerns with the AER's draft decision for capital expenditure in light of the framework outlined earlier in this Chapter. At the overall level, the AER has failed to engage with the detail of our initial 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 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.[138]

and

We do not seek to interfere in the decisions a service provider will make about how and when to spend the total capital expenditure or operating expenditure 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).[139]

This interpretation by the AER, its unreliable and unsafe use of benchmarking and its subsequent failure to engage with our initial proposal 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.[140]

Whilst we accept that the AER does not set a capital expenditure allowance at the project level, it has done so at the program level in its draft decision which implies certain safety and reliability outcomes 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.

Whilst we accept that the AER does not set a capital expenditure allowance at the project level, it has done so at the program level in its draft decision which implies certain safety and reliability outcomes in this decision.

There is detailed guidance in the NER to enable the AER to assess the components of the revenue allowance. For capital expenditure, there are the objectives, criteria and factors which prescribe the AER's assessment approach. We contend that the AER cannot satisfy itself that the capital expenditure forecast forms part of a revenue allowance that satisfies the NEO without conducting a detailed review.

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[138] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p15.

[139] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p16.

[140] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p85.

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, security and reliability and our ability to efficiently meet our obligations as a DNSP.

We sought advice from R2A Due Diligence Engineers in regard to the safety impacts of the AER's draft decision and Jacobs Group Australia in relation to reliability and prudency.

The R2A report, provided at Attachment 1.2, noted:

> *If Essential Energy were to operate within the constraints of the AER's 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 quadrupling of fatalities from networks hazards is most likely to occur. In addition, the likelihood of the Essential Energy network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) triples as a result of increased equipment failures due to longer inspection cycles.*[141]

The Jacobs Group Australia reports are provided at Attachment 1.4 and Attachment 1.5. 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.*[142]
>
> *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.* [143]
>
> *In Jacobs view it is not reasonable to expect the NSW DNSPs to achieve a step change in efficiency of this magnitude. This means that the majority of this expenditure reduction will translate into an increased risk profile rather than increased efficiency; at least within the short to medium term. If expenditure levels are reduced too low the benefits can be expected to be overwhelmed by risk costs in the longer term.*[144]

Assessment starting point

As outlined by the AEMC during the 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 capital expenditure or operating expenditure 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*

[141] R2A, *Essential Energy Asset / System Failure Safety Risk Assessment*, January 2015, p4.
[142] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p2.
[143] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p5.
[144] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p5.

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.[145]

We contend that the AER has failed to demonstrate that it has assessed our regulatory proposal. Rather, it appears the AER…analysed the RIN data which had capital expenditure by different drivers exclusive of overheads.

We contend that the AER has failed to demonstrate that it has assessed our initial proposal. Rather, it appears the AER, and its consultants, did not utilise the capital expenditure by driver proposed by Essential Energy as this included capitalised overheads. Instead, the AER analysed the RIN data which had capital expenditure by different drivers exclusive of overheads. 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 initial 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 in using benchmarking to make its draft determination.

Benchmarking is one of the factors the AER must have regard to in accepting or rejecting a DNSPs proposed capital expenditure. 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.*

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 the 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 drivers which may fall in different periods. Relevant examples are the recent settlements of bushfire related claims by Victorian DNSP's which would not have been captured in the 2006-13 figures, and the introduction of stringent licence conditions in NSW only during the 2006-13 period.

Further to this, the benchmarking analysis concludes that Victorian and South Australian distributors are the most productive, despite productivity declining across the whole sector from 2006 to 2013. The report then fails to mention that both NSW and the ACT have average annual declines in productivity that are better than those experienced in South Australia over the 2006 to 2013 period.

Essential 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 above Victoria in all five periods (08-13, 09-13, 10-13 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.

[145] AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012*, p111.

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 capital expenditure 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 capital expenditure 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 and notified to the AER had it published the report in compliance with the Rules.

Expenditure Forecast Assessment Guideline

In its draft decision the AER states:

> *For Essential 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.*[146]

As per Attachment 6.9 to this proposal we contend that 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' six 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:

> *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.* [147]

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 presents 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. For further discussion please refer to the extensive benchmarking analysis presented in Chapter 7.

We question whether it is appropriate for a consultant of the AER to make this decision [not to include DEA], noting it is the responsibility of the AER to form its own view.

Without transparency and proper explanation, this dismissal of DEA appears subjective and questionable.

[146] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p15.

[147] Economic Insights Pty Ltd, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014.

Unreasonable decision

As outlined in the previous section, the AER's decision for capital expenditure has relied on numerical errors of fact which have led to an incorrect conclusion that has impacted the making of its draft decision. In addition to the issues outlined above we consider the following features of the AER's decision making unreasonable:

- Disproportionate weight on evidence such as benchmarking – setting aside the procedural issues outlined above, we consider the AER has placed undue weight on the benchmarking factor at the expense of detailed, rigorous analysis. The benchmarking analysis for capital expenditure relies on a flawed asset cost proxy (the RAB) and draws inappropriate conclusions based on simple measures such as capital expenditure 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 the AER to more detailed assessments.
- Lack of rigour and depth in AER's 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.*[148]

  and

  ..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[149]

  .. 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.[150]

  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.[151]

[148] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p14.
[149] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p19.
[150] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p25.
[151] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p27.

..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.[152]

- Logical errors – The AER relies on assumptions and views that are illogical. For example, the AER considers 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 caps the percentage of capitalised overheads which can be allocated to capital expenditure ignoring the AER approved CAM. Additionally, the AER suggests a key shortcoming of our proposal is a lack of top down analysis when its consultant EMCa, in assessing replacement capital expenditure, suggested an over reliance on top down analysis existed.

  In contrast to the AER's view, Jacobs noted:

  However, based on the review Jacobs considers the AER's position [in regard to top down assessments] to be inaccurate. Jacobs considers the NSW DNSP's approach clearly demonstrates a considered top-down assessment of their Capex forecasts in reaching their final expenditure proposal. As such, the AER's findings would not appear to justify discounting the Capex forecasting methodologies of the NSW DNSPs and substituting them with the AER's methodology.[153]

  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%.[154]

  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.

- Reliance on consultants – The AER has relied on consultant reports without properly forming their own view on the issues raised. For augmentation capital expenditure, WorleyParsons make no recommendation of the potential reduction to augmentation capital expenditure based on limited analysis. Only eight pages of the report pertain to Essential Energy. Despite this, the AER considers the recommendation valid and selects the top end of the range which is attributed to Endeavour Energy and reduces Essential Energy's augmentation capital expenditure by 20 per cent. This is in contrast to both Ausgrid and Endeavour Energy, who were given the midpoint of 15 per cent. No justification or evidence is provided as to how the AER selected these arbitrary percentages. Jacobs noted that:

  …there appears to be a lack of analysis from which the basis for the application of 15% and 20% are made. Further, there is a lack of analysis from which the initial 10-20% value has been determined, other than "it would be reasonable to expect. [155]

- Not undertaken a review of the impact of its substitute allowance in terms of risks to safety, security and reliability - 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 capital expenditure 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 capital expenditure objectives and criteria. The safety, security and reliability implications of the draft decision are unknown despite reductions being made to specific programs and capital expenditure drivers.

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[152] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p44.
[153] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p25.
[154] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p26.
[155] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p2.

R2A observed that:

The AER appears to accept that there will be an increase in unexpected events resulting from this draft determination:

> *"Where an unexpected event leads to an overspend of the capex amount approved in this determination as part of total revenue, a service provider will be only required to bear 30% of this cost if the expenditure is found to be prudent and efficient. For these reasons, in the event that the approved total revenue underestimates the total capex required, we do not consider that this should lead to undue safety or reliability issues."*

The AER draft determination as it stands is, in effect, directing Essential Energy to disregard Essential Energy's own determination of what Essential Energy believes is necessary to demonstrate SFAIRP under the provisions of the Work Health and Safety Act 2011.[156]

Jacobs stated:

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. [157]

In light of the procedural issues detailed in this section, we consider there is only limited scope for Essential Energy to revise our initial proposal. The flawed approach relied on by the AER has impacted the credibility and validity of their findings.

In light of the procedural issues detailed in this section, we consider there is only limited scope for Essential Energy to revise our regulatory proposal.

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 significant variations to our initial proposal. The AER's decision does not reflect the revenue and pricing principles in the NEL, particularly the substitute capital expenditure amount does not provide a reasonable opportunity to recover our efficient costs. As such, Essential Energy has only made minor revisions to the capital expenditure in the initial proposal.

Generally, we do not consider the AER has raised valid issues that require significant variations to our initial proposal.

In its assessment of the capital expenditure forecast the AER, as per the expenditure forecast assessment guideline, utilised 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:

[156] R2A, *Essential Energy Asset / System Failure Safety Risk Assessment*, January 2015, p4.
[157] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p53.

> *…the overall forecast expenditure will result in the lowest sustainable cost (in present value terms) to meet the legal obligations of the DNSP.*[158]

Our consideration of the issues raised by the AER's top down and bottom up methods is contained in the sections below.

AER's top down analysis

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 capital expenditure 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 capital expenditure that are acceptable in its consideration of our historical performance and current organisational, network and environmental factors. This is explained in further detail in the capital trends and changes section below.
- 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 capital expenditure consisted of high level benchmarking analysis and more targeted benchmarking as part of detailed analysis. The benchmarking analysis relied on was published in its annual benchmarking report on 27 November 2014. As outlined in the previous section, the AER has utilised benchmarking in their assessment of our proposed capital expenditure 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 our capital expenditure forecasts. Furthermore, high level sensibility checks clearly identify significant issues with substituted forecasts resulting from benchmarking.

For example, a high level sensibility check on replacement capital expenditure reveals that Essential Energy received a similar amount of replacement capital expenditure as Endeavour Energy for a network that is 546 per cent longer. For these reasons, we consider the AER should have placed very limited weight on that benchmarking analysis.

> *…capital expenditure is even less suited to benchmarking than operating expenditure given its non-recurrent and/or lumpy nature.*

We are of the view that capital expenditure is even less suited to benchmarking than operating expenditure given its non-recurrent and/or lumpy nature. The AER's

[158] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p17.

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 capital expenditure should receive considerably more weight than such a high level, error prone tool.

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, Frontier Economics, Pacific Economics Group and Professor David Newbery to undertake technical reviews of the AER's benchmarking report. Huegin, Frontier Economics, Pacific Economics Group and Professor David Newbery and are experts in benchmarking, with significant knowledge and experience in applying such tools. Huegin's report can be found at Attachment 6.9, 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 from the Guideline it would have found an entirely different ranking of DNSPs.

We have also conducted analysis and sensibility checks on the outcomes of the AER's benchmarking. This analysis can be found at Attachment 6.6, with the key conclusions being:

> Essential Energy has 4.5 times the number of poles and 5.5 times more circuit kilometres than Endeavour Energy, however the AER's draft decision only allows Essential Energy less than five per cent more replacement capital expenditure.
> Essential Energy has 1.5 times the number of poles and 1.6 times more circuit kilometres than a combined AusNet Services and Powercor, however the AER's draft decision allows only 90 per cent of the historical replacement capital expenditure for a combined AusNet Services and Powercor.
> The average replacement capital expenditure per asset for Essential Energy is substantially below a combined AusNet Services and Powercor.

Based on this evidence we consider that the benchmarking analysis contains errors, and accordingly it would be unreasonable for the AER to apply significant weight to that analysis when forming its view on the efficiency of the forecast.

Capital trends and changes

Our proposed capital program was 43 per cent lower than the allowance for the 2009-14 regulatory period. This reduction reflected the achievement of mandatory licence conditions during 2009-14, reduced forecast demand growth and delivery efficiencies. Whilst capital expenditure is non-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 May 2008.

In rejecting our proposed capital expenditure the AER has relied on a number of assessment techniques, including a high level assessment of the changes and trends in our proposed capital expenditure. Similar to the benchmarking analysis described above, the AER has formed the view that our overall capital program does not reasonably reflect the capital expenditure criteria and is therefore not prudent or efficient.

Specifically, the AER has determined that a larger reduction to capital expenditure from the 2009-14 regulatory period is warranted based on the following factors:

- 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 capital expenditure 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 regulatory period, demand growth was not a major driver of investment at a global level. Rather, our reduced 2014-19 proposed capital expenditure is driven by the need to augment the network at a local level to cater for spatial demand growth.

In response to AER questions Essential Energy provided updated demand forecasts which were marginally higher 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 capital expenditure.

We have not revised our initial proposal to address these matters as they represent high level, flawed analysis. The capacity installed during the 2009-14 regulatory period primarily addressed licence conditions, and we consider it inappropriate to suggest this investment was inefficient or unnecessary when it represented a regulatory obligation. Irrespective of this, global peak demand or utilisation of existing assets are not the main drivers of our proposed augmentation capital expenditure forecast. Our augmentation capital expenditure program is primarily driven by spatial demand growth, i.e. pockets of demand growth. It is not feasible, practical or possible to service these areas with existing assets located in physically different areas. Further discussion can be found at Attachment 6.7. As described earlier, the AER also made a significant error in its ratcheted demand calculation.

> *… capacity installed during the 2009-14 regulatory period primarily addressed licence conditions, and we consider it inappropriate to suggest this investment was inefficient or unnecessary when it represented a regulatory obligation.*

Licence conditions

As previously noted, we consider our capital program has been substantially reduced compared to the 2009-14 regulatory 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 capital expenditure for the 2014-19 regulatory period.

> *We consider that the change in licence conditions is likely one of the key reasons for the reduction in capex proposed by Essential Energy for the 2014–2019 regulatory control 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 capital expenditure for the 2009–2014 regulatory control period.*[159]

[159] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure, November 2014,* p29

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 2009-14 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.

…network performance pre 2005 was a key reason why the licence conditions were introduced. Therefore, the AER is essentially prescribing a repeat of this history in future periods.

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 capital expenditure similar to pre 2005. By prescribing cuts to capital expenditure 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 initial proposal and supporting information that it is the achievement of the licence conditions at 30 June 2014 that drives the reduced capital expenditure 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 Essential 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 regulatory period would the removal of certain licence conditions materially alleviate investment needs in the 2014-19 regulatory period.

It is also important to note that in any case, Essential Energy has indeed reduced its augmentation capital expenditure significantly as a result of achieving compliance with the licence conditions.

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.

Forecasting method

We assert that we use both top down and bottom up methods in developing our capital expenditure forecast. The view by the AER that a top down review was not conducted is incorrect; this is supported by the following finding in a review carried out by Jacobs Consulting (Attachment 1.4):

> *However, based on the review Jacobs considers the AER's position to be inaccurate. Jacobs considers the NSW DNSP's approach clearly demonstrates a considered top-down assessment of their capex forecasts in reaching their final expenditure proposal. As such, the AER's findings would not appear to justify discounting the capex forecasting methodologies of the NSW DNSPs and substituting them with the AER's methodology.*[160]

Essential Energy has outlined our use of bottom up and top down approaches in the development of the capital forecast. In particular the common NNSW's top down prioritisation of the program was used to assess risk, challenge the forecast, identify synergies and provide top down constraint. This approach complements a bottom up method which examines in detail:

- Safety, environment and regulatory requirements
- Asset condition
- Forecast demand and development activity

[160] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p25

- 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
- Pre-defined criteria that form the basis of asset health index and trigger a flag for asset refurbishment and replacement (for major equipment groups).

Detailed information on the governance process and top down review undertaken is provided in Attachment 6.2. Our position is further supported by a review of the forecasting process conducted by Jacobs Consulting - Attachment 1.4. In particular for the replacement capital expenditure forecast Jacobs Consulting found that:

> *In any case, the repex forecasts produced by the NSW DNSPs were based on the sound application of asset condition assessments. In previous regulatory determinations, the AER has endorsed the approach of a bottom-up build based on actual condition and has been critical of only using age based modelling to forecast expenditure. In our opinion, the use of both bottom-up and top-down assessment are critical to determine a prudent level of replacement expenditure.*[161]

Overall Jacobs Consulting found that:

> *Moreover, 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.*[162]

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 capital expenditure program represents a reasonable estimate of the lowest cost solution to address a genuine network need. We have not revised our framework, and therefore capital expenditure forecasts, to address this matter as we do not consider evidence has been provided to demonstrate an overestimation bias or overly conservative position.

We have a prudent and robust process in place to ensure that our capital expenditure program represents a reasonable estimate of the lowest cost solution to address a genuine network need.

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 approval of the Essential Energy developed risk prioritised investment portfolio by the Board (Gate 1). Effective risk based prioritisation enables the Board to make an informed decision based on its

[161] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p4
[162] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p25

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 five million dollars 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 five million dollars are tested through an independent and peer review prior to approval.
- Ongoing reporting and monitoring of projects against time and budget.
- 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 summarised below and included in Attachment 6.2:

- Charters of our relevant committees
- Relevant company policies and procedures
- Business cases
- Change management process and procedures
- Change controls
- Corrected capital governance framework.

In relation to the capital governance framework, the AER's draft decision stated our framework was out of date and inconsistent with Networks NSW' Capital Governance Framework, but these findings are invalid. Essential Energy has been working to the common Networks NSW governance process since 2013. Our initial proposal incorrectly included reference to a legacy governance process document, however, updated information about Essential Energy's capital governance framework was provided to EMCa at the onsite workshop on 27 August 2014 and in response to follow-up requests for information from EMCa. This updated information has not been referenced in the EMCa report. This report provides evidence of the current governance framework and processes adopted by Essential Energy, and demonstrates its consistency with the Networks NSW process. More information can be found in Attachment 6.2.

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 capital expenditure 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
- Reputation[163]
- Network reliability
- 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 committees review the resulting portfolio and provide 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 constraint points, 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 reflects 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.

Subsequent to the submission of our initial proposal we had an independent review conducted into our risk based prioritisation process. Advisian, 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.

> *Advisian…noted that there were a number of very significant positive aspects to our [risk prioritisation] 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 capital expenditure 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. The recommended improvement opportunity not yet implemented is not expected to result in a material change to the risk position adopted by the Board.

Jacobs found that the business had a well-developed process to apply both bottom up and top down reviews of programs. Jacobs report makes the following comments regarding capital program governance and related risk prirotisation:

> *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.*[164]

[163] 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 capital expenditure forecast in this revised regulatory proposal.

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

The (Jacobs) review shows that, contrary to the AER's finding, the NSW DNSPs have used a two-layered iterative approach that employs both a bottom-up and a top-down assessment to develop the Capex forecasts. This approach is intended to ensure that each of the NSW DNSPs propose a Capex forecast that is both prudent and efficient.[165]

In Jacobs' view it appears that, in reaching its finding that the NSW DNSPs have applied a bottom-up assessment but not a top-down assessment, the AER has overlooked the following:

- *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.*[166]

..it appears that 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.

Critically, the conclusions do not appear to have been formed with appropriate consideration given to the CASH/PIP risk prioritisation tool applied in conjunction with NNSW over the entire NSW DNSP capital programme. This tool is independent of the NSW DNSP's internal risk assessments. It provides the calibrating mechanism for regulating the risk assessments used by the three NSW DNSPs and for providing a prioritised Capex programme.

The AER has used the CASH/PIP process to conclude that the Capex programmes are overly risk averse, rather than considering its key role of ensuring that "restraint is brought to bear"; which is one of the criteria identified by the AER as reflective of a robust top-down assessment.[167]

However, based on the review Jacobs considers the AER's position [in regard to top down assessments] to be inaccurate. Jacobs considers the NSW DNSP's approach clearly demonstrates a considered top-down assessment of their Capex forecasts in reaching their final expenditure proposal. As such, the AER's findings would not appear to justify discounting the Capex forecasting methodologies of the NSW DNSPs and substituting them with the AER's methodology.[168]

> *"…the AER's findings would not appear to justify discounting the Capex forecasting methodologies of the NSW DNSPs…"* (Jacobs)

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.

Jacobs also notes that while the AER has discounted the NSW DNSP Capex forecasts because it considers them to be based on overly conservative risk assessments, it does not appear to have carried out any form of risk assessment in its substituted Capex forecast approach. The AER appears to be taking a position on expenditure without apposite consideration of the risk profiles associated with the

[165] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment,* January 2015, p13.
[166] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p14.
[167] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p19-20.
[168] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p25.

varying levels of expenditure. In particular, the AER's approach does not appear to consider "risk level metrics [as] key elements of capex drivers" within its substituted Capex forecast approach.[169]

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:

- The prioritised risk master list that underpinned the capital expenditure forecast in the initial 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.
- A copy of the Advisian (formerly Evans and Peck) review of the risk based prioritisation process.

Advisian have 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 6.10.

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 that the AER has 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.

Based on the information we have provided, we believe that the AER has 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.

Review by capital expenditure category

In addition to a top down review of the overall capital expenditure the AER examined disaggregated capital expenditure by driver. In forming a view as to whether the total forecast capital expenditure reasonably reflects the capital expenditure criteria the Guideline requires that the AER examine the volumes and costs applicable to drivers of capital expenditure. In acknowledgement, but in apparent contradiction of the approach applied by the AER to benchmarking of the complex nature of capital expenditure, 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.[170]

In addition to this, the AER's Guideline outlines the assessment approach specific to each driver of capital expenditure. The drivers being:

- Replacement
- Augmentation
- Connection and customer driven works
- Non-network capital expenditure.

We consider that sufficient information was provided to enable this assessment and demonstrate that each category reasonably reflected the capital expenditure criteria.

[169] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, pp27.
[170] AER, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution,* November 2013, p17

In our initial proposal, we outlined the reasons for our capital expenditure by driver and provided evidence for each of these programs. Unlike operating expenditure, capital expenditure can be lumpy in nature and driven by an array of complex factors, obligations and needs. As such, grouping capital expenditure 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 capital expenditure based on a combination of top down and bottom up analysis of the overall program and its subcategories. The AER considered the disaggregated capital expenditure by driver and projects within these programs did not reflect the prudent and efficient level of expenditure based on their assessment and consultant advice.

In considering whether to revise our initial 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:

… we contend that the AER did not properly consider the information we provided to demonstrate that our costs were efficient and prudent.

> *… 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.*[171]

In the following sections we review the AER's decision regarding each category of capital expenditure and consider whether the matters raised by the AER require revision.

Augmentation capital expenditure

In our initial proposal we forecast $745 million ($2013-14) of augmentation capital expenditure for the 2014-19 regulatory period. This expenditure was designed to service spatial demand growth and compliance programs. The supporting attachments to our initial proposal provided further detail as to our growth servicing strategy and the key business cases related to our augmentation capital expenditure program.

In its assessment the AER has focused on the demand forecast, network utilisation and consultant advice. The AER has rejected our forecast and substituted an amount of $475 million (2013-14) excluding overheads, a reduction of 36 per cent according to the AER. In forming this view the AER's assessment approach utilised trend analysis, an engineering review and the augex model, which culminate in the identification of two reasons for recommending the change to Essential Energy's forecast. The breakdown and the key reasons provided by the AER in making this reduction are as follows:

- *reduced Essential Energy's augex forecast by approximately 20.2 per cent to account for updated spatial demand forecasts*
- *applied a further 20 per cent reduction to account for the absence of Essential Energy applying a risk-based cost benefit analysis technique*

> *These reductions take into account the observed trend in augex that shows that there is excess capacity in the network that remains to be more efficiently utilised.*[172]

[171] Australian Competition Tribunal, *Application by EnergyAustralia and Others [2009] ACompT 8*, p56.

[172] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p10.

The AER have expanded on their first reason for the reduction in augmentation capital expenditure on page 6-34 where the AER state:

> *56 per cent of Essential Energy's augex forecast was based on capacity requirements for their HV network. Essential Energy provided a draft of their 2014 demand forecasts that show a reduction in ratcheted demand of 35.67 per cent. We have used Essential Energy's draft 2014 spatial demand forecasts to reduce the expenditure required for its HV feeders by 35.67 per cent. This follows from analysis by Ausgrid which concluded a positive linear relationship exists between a change in forecast demand and expenditure requirements for HV feeders[173].*

At a fundamental level, it appears the AER has relied on a misconception that our proposed augmentation capital expenditure is driven by global peak demand.

At a fundamental level, it appears the AER has relied on a misconception that our proposed augmentation capital expenditure 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 6.7 to this revised proposal for a detailed response. A summary of our position on each of these issues is as follows:

> The AER have made an error when calculating Essential Energy's ratcheted demand. The AER excluded the forecast growth on several substations, due to an error in its spreadsheet. When these loads are included in the AER's spreadsheet the ratcheted demand changes from negative 35 per cent growth to positive 8 per cent growth.

> The AER's trend analysis appears to be a mixture of benchmarking and consideration of macro factors such as licence conditions and capacity utilisation. Essential Energy developed a forecast utilising a bottom up method which accounted for our operating environment and obligations at our subtransmission level and a top down approach based on historical data for distribution forecasts. The AER's consultant WorleyParsons supported the use of past expenditures in the forecasting of distribution augmentation capital expenditure.

> Essential Energy did not use the forecast demand to determine the future expenditure on HV feeder augmentation capital expenditure. The forecast was based on the average of the actual 2012-13 and forecast 2013-14 expenditures. These two years are the lowest historical level of growth on the Essential Energy network and hence conservatively represent the lowest likely HV Feeder augmentation capital expenditure. The reduction in growth expenditure in 2013-14 is as a direct result of the negative growth in this year. The actual growth that has been forecast for the 2014-19 regulatory period is higher than the growth in 2012-13 and 2013-14, however the forecast expenditure has been held at this lower base level.

> The drivers for augmentation capital expenditure are not all impacted by growth and it is not correct to apply a linear relationship to the total HV Feeder Augmentation capital expenditure.

> Essential Energy distribution network augmentation capital expenditure during the 2012-13 to 2013-14 period was reactive (only carrying out projects where and when required) and coincides with the lowest growth experienced on the network, it is not reasonable to suggest that the distribution expenditure can be reduced through a risk assessment. By using this period as our base for our forecasts we are taking the maximum risk allowed to maintain mandatory supply standards.

> Schedule 1 of the Reliability Licence Conditions required HV feeder work in only 19 regional towns over the whole of rural NSW and then only on the front section of the feeder. It is highly unlikely that this reduction in utilisation will constitute a reserve of capacity to allow future augmentation to be deferred. The intention of the N-1 security standard for distribution feeders was to allow faster response to outages in existing urban areas of the network. No technical review has been conducted by the AER to

[173] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p34.

validate the legitimacy and practicality of their position that the lower utilisation will lead to reduced future augmentation capital expenditure.[174]

The AER has expanded on their second reason for the reduction in augmentation capital expenditure with the following statement:

> *..based on independent advice from WorleyParsons, it is evident that Essential Energy's augex forecast is biased because it has not sufficiently taken into account the impact of the changes to the NSW licence conditions design standards that took effect on 1 July 2014. WorleyParsons concluded that Essential Energy could achieve efficiency gains by applying a risk-based cost benefit analysis assessment techniques to new and ongoing programs of work. In light of this advice, and the observed trend in augex, we have applied a further 20 per cent reduction to account for the absence of Essential Energy applying a risk-based cost benefit analysis technique. In our view, this reduction will not put at risk Essential ability to recover at least its efficient costs.*[175]

In regard to each of the key points raised by the AER and their assessment approach, refer to Attachment 6.7 to this revised proposal for a detailed response. A summary of our position on each of these issues is as follows:

- The AER has used a global reduction of 20 per cent to Essential Energy's augmentation capital expenditure based on the AER's perception that we have not fully allowed for the change in licence conditions. Our initial proposal was based on adopting the maximum allowed risk by excluding all distribution expenditure which is not mandatory. This is recognised in the WorleyParsons report when they state:

  The expenditure in most subcategories is reactionary and due primarily to the consequences of growth, e.g. power quality issues. Although overall growth projections are flat there will be local pockets of growth and Essential considers that the expenditure over the past two years under similar conditions is the best indicator of future requirements.[176]

- As Essential Energy distribution augmentation capital expenditure is reactive and is based on a network constraint, it is not reasonable to suggest that the distribution expenditure can be reduced through a risk assessment. By taking a reactive approach to distribution planning (only carrying out projects where required and when required), and only carrying out projects that are mandatory, means that we are taking the maximum risk allowed to maintain mandatory supply standards.
- The observed trend in distribution augmentation capital expenditure has been allowed for by using the lowest growth years as the basis for the forecast distribution augmentation capital expenditure. The reduction in growth expenditure in 2013-14 is as a direct result of the negative growth in this year. The actual growth that has been forecast for the 2015-19 period is higher than the growth during the 2012-13 and 2013-14 years, however the forecast expenditure has been held at the base years.
- All distribution augmentation capital expenditure to meet Schedule 1 of the NSW reliability licence condition was excluded from Essential Energy's initial proposal. Essential Energy did reduce the proposed expenditure on the subtransmission network based on the expected outcome of the review of the licence conditions. This review resulted in a reduction of $45 million. In light of the published VCR a full risk based review of all projects has now been carried out and an additional $18.6 million has been identified for deferment.
- Essential Energy has forecast augmentation capital expenditure over the 2014–2019 regulatory period of $744 million ($2013–14). This is 44 per cent less than the actual augmentation capital expenditure

[174] AER, *Draft Decision – Essential Energy Distribution Determination 2015-15 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p38.
[175] AER, *Draft Decision – Essential Energy Distribution Determination 2015-15 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p34.
[176] WorleyParsons, *Review of Proposed Augmentation Capex in NSW DNSP Regulatory Proposals 2014-19,* 17 November 2014, p.21.

that it spent during the 2009–2014 regulatory period. Essential Energy's augmentation capital expenditure for distribution expenditure is based on the lowest growth years historically and lower than the expected growth during the 2014-2019 regulatory period. Essential Energy's augmentation capital expenditure at subtransmission level is itemised with every project being reviewed internally and externally to ensure compliance with the latest VCR changes.

> We do not consider the 20 per cent reduction applied by the AER based on the 10-20 per cent range provided by WorleyParsons to Endeavours' network is reasonable. In their review of Essential Energy's augmentation capital expenditure, WorleyParsons state: "T*he application of risk based cost benefit analysis assessment techniques to projected programs of work would likely result in reductions to projected expenditure".*[177] The consultant report does not indicate that the reductions for Essential Energy would be in the order expected for Endeavour Energy. The AER provides no substantiation for a conclusion to apply a 20 per cent reduction which appears to be an arbitrarily determined result. Essential Energy has now assessed and incorporated the changes to the VCR as requested by the AER in its draft decision, meaning the forecast augmentation capital expenditure is now based on more rigorous options analysis compared to the arbitrary 20 per cent reduction; and

> A technical review or assessment of the substitute forecast against the capital expenditure 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.

Consistent with the above points, Jacobs observed:

..we consider the AER's reduction to augmentation expenditure based on a linear relationship between Augex and demand growth to be reasonable for the purpose of forecasting expenditure if it is assumed that the augmentation is only driven by underlying demand growth. That is, 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.

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.[178]

and

…[WorleyParsons] identified range of 10-20% is a speculation that is not robustly substantiated and is discussed only with respect to Endeavour Energy. The AER has then applied this speculation to all NSW DNSPs.

…It does not appear that specific Augex program reductions made by the DNSPs to their baseline Augex forecasts have been considered. These reductions were not part of the CASH/PIP process.[179]

Table 3-4 of the Jacobs report sets out details of $214 million in augmentation capital expenditure which were excluded from the programs of the NSW DNSP's prior to development of their initial proposals. This is the same adjustment referred to above, which was detailed to the AER in response to an AER query following submissions. In relation to these reductions Jacobs noted:

…[Table 3-4] demonstrates that the NSW DNSPs:

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177 WorleyParsons, *Review of Proposed Augmentation Capex in NSW DNSP Regulatory Proposals 2014-19*, 17 November 2014, p.22.
178 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p2.
179 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p3.

- *Have carried out a cost-benefits review in relation to the changes to the Licence Conditions; and*
- *Through this review have achieved a reduction of 13% to the combined Augex forecast. Incidentally, this sits within the speculated 10-20% "reasonable range' identified in the report.*[180]

Jacobs also notes that while the consultant's report acknowledges that further Augex reductions would have been achieved through the CASH/PIP process, it does not appear that the magnitude of these reductions have been taken into account is establishing the speculated "reasonable range"…. It is noted that the $214 M reduction made by the NSW DNSPs is an outcome of a detailed technical assessment process. Given this, it is our opinion that it is imprudent to simply speculate on a percentage reduction based on arguable reasonableness (as the AER appears to have done). Rather, it is necessary to apply further detailed analysis to determine the potential for any additional reductions beyond that which the DNSP's have already identified through detailed analysis.[181]

For these reasons, Essential Energy has not revised its proposal to adopt the AER's draft decision on augmentation capital expenditure as we do not consider it will contribute to the achievement of the capital expenditure objectives. In light of the AER's decision we reviewed our augmentation capital expenditure forecast to ensure it reflected the efficient cost of servicing demand growth and to reflect the latest available information. As such, we have reduced our proposed program by $18.2 million ($2013-14), specifically in response to the new VCR value determined by AEMO and a risk based review of all projects. However, this reduction has been offset by the LiDAR program of work, which has identified $77 million ($2013-14) of high risk low clearance mains defects. Overall our forecast has increased from our initial proposal for the 2014-19 regulatory period.

…we have reduced our proposed [augmentation capital expenditure] program by $18.2 million … However, this reduction has been offset by the LiDAR program of work…

These revisions are discussed in more detail later in this Chapter and in Attachment 6.7.

In its draft decision, the AER requested that the revised proposal provide a response to several additional points including:

> A clear explanation of how capital contributions should be allocated to each capital expenditure driver.

> Capital contributions are the value of the assets that are gifted to Essential Energy through the contestability framework in NSW. These assets are generally the connection assets required to connect the new customer to the existing network, however in rural areas and for dominant loads it may include some augmentation of existing assets. Essential Energy does not capture gifted assets into separate categories and capital contributions have been reported within connections.

> An expectation that Essential Energy will provide labour costs as a proportion of total forecast capital expenditure in its revised proposal.

180 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p30.
181 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p31.

As illustrated in Table 6.5 the impact of labour escalators on capital expenditure is $32 million over the 2014-19 regulatory period.

Table 6-5: Impact of labour escalators on forecast capital expenditure ($2013-14, millions)

	Forecast year ending 30 June					
	2015	2016	2017	2018	2019	Total
Revised EGW wages real labour escalation rate	0.71%	1.00%	1.55%	1.56%	1.44%	n/a
Revised general wages real labour escalation rate	0.68%	1.33%	1.27%	1.17%	1.20%	n/a
Capital expenditure excluding labour escalators	519	523	511	484	459	2,496
Revised capital expenditure – post real escalation	520	527	518	493	471	2,529
Impact of labour escalation included in RRP	**1**	**3**	**7**	**9**	**12**	**32**

> An expectation that Essential Energy will assess the changes to the VCR in the submitting a revised proposal.

  In light of the published VCR, a full risk based review of all projects has now been carried out and an additional $18.2 million ($2013-14) has been identified for deferment.

> A draft decision to not include an explicit recognition for demand management.

  While useful tools, Essential Energy does not consider that the current RIT-D and Annual Planning Report alone provide the most appropriate approach in providing incentives for the optimal amount of demand management. A broad incentive scheme must be employed to ensure low cost options particularly those with broad, whole of market benefits are employed appropriately, whilst also ensuring that the scheme does not promote the use of non-cost effective outcomes.

  The appropriate capital expenditure/operating expenditure trade-off that should be included goes to the core of the AEMC's upcoming review on reforming the demand management and embedded generation connection incentive scheme, expected to commence consultation in early 2015. Essential Energy does not consider it appropriate to pre-empt the outcome of this reform but we support a simplified D-factor type mechanism incorporating the deemed value of up-stream benefit resulting from demand management projects.

  Many of these issues where discussed in Ausgrid's response to an AEMC issues paper submitted on 16 September 2011 as part of the Power of Choice review.[182]

Replacement capital expenditure

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 Essential Energy's proposed replacement capital expenditure forecast of $857 million ($2013-14) and substituted an amount of $675 million ($2013-14)

[182] Ausgrid, *Ausgrid's response to the AEMC's DSP3 Issues Paper*, September 2011

excluding overheads. The breakdown and the key reasons provided by the AER in making this reduction are as follows:

> *Essential Energy's proposal is around 59 per cent higher than Essential Energy's historical trend (inclusive of overheads) and compares unfavourably on a number of category level benchmarks which we have taken into account.*
>
> *Our consultant, EMCa has found a number of issues with Essential Energy's proposal which we accept. These issues include Essential Energy using overly conservative risk criteria……..*
>
> *The network health indicators concerning the condition of Essential Energy's assets do not support a significant increase in repex relative to the longer term trend of actual repex that Essential Energy has spent in past regulatory control periods.*
>
> *Essential Energy faced significant capex deliverability challenges during the 2009-2014 regulatory control period. We have found no evidence to suggest that Essential Energy is better equipped to deal with or will not face these same challenges during the 2014-2019 period.* [183]

In forming this view it is unclear what weighting was assigned to these issues. It appears the AER's assessment primarily relied on a mechanistic application of their repex model. Despite this, several issues are raised by the AER within its draft decision regarding our replacement capital expenditure which are addressed below.

In regard to each of the key points raised by the AER and their assessment approach refer to Attachment 6.6 to this revised proposal for a detailed response. Whilst it is not clear what weighting was assigned to the analysis and issues raised within the AER's decision outside of the repex model in forming their view, our response to these issues is as follows:

- 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 with. 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 benchmarking measures do not account for the significant number of operating and environment factors that may impact the results.

- The long term average replacement capital expenditure covers the 2001-2014 period to determine a replacement capital expenditure allocation that the AER considers reasonable for the 2014-19 regulatory period without any reference to the age profile or condition of the assets. This approach is illogical; the AER should match the cost average to the forecast age profile and adjust to what 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 particularly when there has been no attempt to correlate with asset age and condition resulting in misleading and erroneous conclusions;.
- The long term average is a simple measure that is significantly less refined than our bottom up build based on asset condition and failure history with sense checking through asset age profiles.
- We consider the EMCa report does not constitute an adequate technical review of our proposal. The findings are based on numerous factual and

…we consider the EMCa report does not constitute an adequate technical review of our proposal.

183 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure,* November 2014, p11

logical errors, unreasonable views and high level analysis that are not supported by evidence or sound engineering practice. We do not consider it is of sufficient quality, competency or accuracy to be relied upon by the AER in making its determination.

- A technical review or assessment of the substitute forecast against the capital expenditure factors and criteria has not been conducted by the AER to understand the safety, reliability and long term implications of the AER's decision. 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.
- In regard to the AER's application of their repex model there are a number of modelling and data errors that have driven incorrect outcomes including.
    - The service mains category has been understated due to the forecast service replacement cost per service being applied by the AER to the kilometres of service mains forecast for replacement. This understates the model output by approximately $39 million;
    - In the repex model the AER have replaced the pole staking rate of Essential Energy (18 per cent) of all timber poles with the pole staking rate of Ausgrid low voltage timber poles (47 per cent). This has been done with no apparent regard to the widely disparate pole serviceability criteria of Ausgrid and Essential Energy. Such a decision without due engineering analysis and regard for risk is poor engineering practice and, without an adequate engineering knowledge of the facts, a reckless decision. This understates the model output by approximately $49 million;
    - There are a number of projects/programmes that have step changes which the repex model cannot accommodate due to no or little prior history. We request that these be reconsidered as if no replacement programmes are implemented the emerging risks will remain as latent conditional failures resulting in an increase in the risk profile of the network. These projects/programs are understated in the model outcome by approximately $34 million; and
    - An error by Essential Energy where the historical switchgear replacements were understated has resulted in the repex model understating switchgear replacement by approximately $11 million.

… the AER have replaced the pole staking rate of Essential Energy staking rate of Ausgrid. Such a decision without due engineering analysis and regard for risk is poor engineering practice and, without an adequate engineering knowledge of the facts, a reckless decision.

In their report, Jacobs (Attachment 1.4) made a number of observations which are consistent with the above points:

> *Following its decision not to accept the Expenditure Proposals of the NSW DNSPs the AER has determined revised Repex forecasts through predictive modelling using its own Repex Model.*[184]

> *The AER has not provided trend comparisons of asset age profiles or Repex expenditure for the benchmarked DNSPs. If the DNSPs on the "efficient frontier" have aging assets during the period this may simply demonstrate a riskier profile rather than greater Repex efficiency. In Jacobs view it would be imprudent to draw conclusions on this analysis without an understanding of the age profiles (and risk profiles by proxy) and the asset failure performance of the benchmarked DNSPs.*[185]

Critically, Jacobs has noted that while the AER has discounted the NSW DNSP Repex forecasts because it considers them to be based on overly conservative risk assessments, it does not appear to have carried out any form of risk assessment in its substituted Repex forecast approach.

[184] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p33.

Critically, Jacobs has noted that while the AER has discounted the NSW DNSP Repex forecasts because it considers them to be based on overly conservative risk assessments, it does not appear to have carried out any form of risk assessment in its substituted Repex forecast approach. The AER appears to be taking a position on expenditure without apposite consideration of the risk profiles associated with the varying levels of expenditure. In particular, the AER's approach does not appear to consider "risk level metrics [as] key elements of capex drivers" within its substituted Capex forecast approach.[186]

The estimated residual service life analysis is not considered in the context of the age profiles of the assets and draws flawed conclusions as a result. Specifically it is based on averages and assumed a normal distribution of assets. It does not consider how the proportions of new and aging assets affect the average residual life analysis. Hence, conclusions are not based on the actual proportion of assets reaching the end of the serviceable life that will require replacement.[187]

The estimated residual service life analysis is not considered in the context of the age profiles of the assets and draws flawed conclusions as a result. Specifically it is based on averages and assumed a normal distribution of assets. It does not consider how the proportions of new and aging assets affect the average residual life analysis. Hence, conclusions are not based on the actual proportion of assets reaching the end of the serviceable life that will require replacement.[188]

.. the largely unsubstantiated use of the "Calibrated Forecast" Repex Model means the implicit area of difference is that the AER considers the NSW DNSP's assets to have longer replacement lives than advised by the DNSPs.

Jacobs' understanding is that the remaining lives of the assets is "calibrated" based upon the Repex activities over the 2009-14 period. In Jacobs view this is unlikely to accurately capture realistic Repex requirements; especially for low-volume / high-value assets. The AER has not substantiated why it considers this window to accurately reflect ongoing Repex requirements.

.. 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.[189]

Table 6-6 shows that the repex model provides a wide range of results and the AER have selected the lowest option of the reasonable outcomes for the modelled replacement capital expenditure (excludes unmodelled replacement capital expenditure).

Table 6-6: Summary of relevant Repex Model outcomes

Asset Life	Unit Cost	Model Outcome
NEM Benchmark	Essential Historical	$1,157.1
NEM Benchmark	Essential Forecast	$960.2
NEM Benchmark	NEM Benchmark average	$1,174.2
Essential Calibrated	Essential Forecast	$589.7 – AER Selected Outcome
Essential Calibrated	Essential Benchmark	$682.1

185 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p35.
186 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p37.
187 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p43.
188 Jacobs, Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment, January 2015, p43.
189 Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p44.

The lowest outcome of the reasonable range that the AER has selected from their model is concerning in that:

- It is clear from the AER's produced scenarios that range from 1.15 per cent above to 51.4 per cent below the allocated replacement capital expenditure in its draft decision that the repex model is highly sensitive to the input data.
- Essential Energy has the second oldest weighted calibrated asset lives in the NEM at 70.3 years, only exceeded by the incomparable city underground network of CitiPower.
- The repex model is highly dependent on calibrated life, with the 2.8 years older calibrated lives of Essential Energy compared to the NEM weighted average resulting in $218 million less replacement capital expenditure for Essential Energy.
- This high calibrated asset life is indicative of a historically low replacement capital expenditure spend profile. Figure 6-3 highlights this with a comparison of the historical and forecast replacement capital expenditure spend as a percentage of the replacement cost of a number of NEM DNSP's.

Essential Energy's higher calibrated replacement life is evident in the historical spend profile, displayed in Figure 6-3, which shows that Essential Energy has historically low replacement rates that are at the bottom end of the range of industry performance. Figure 6-3 provides a benchmark of replacement capital expenditure normalised by the asset replacement cost of each DNSP. This is used due to the strong correlation between asset quantities and replacement capital expenditure demand. To develop Figure 6-3, each DNSP's asset quantities are applied to the AER's provided NEM benchmarked unit costs to provide an asset base replacement cost.

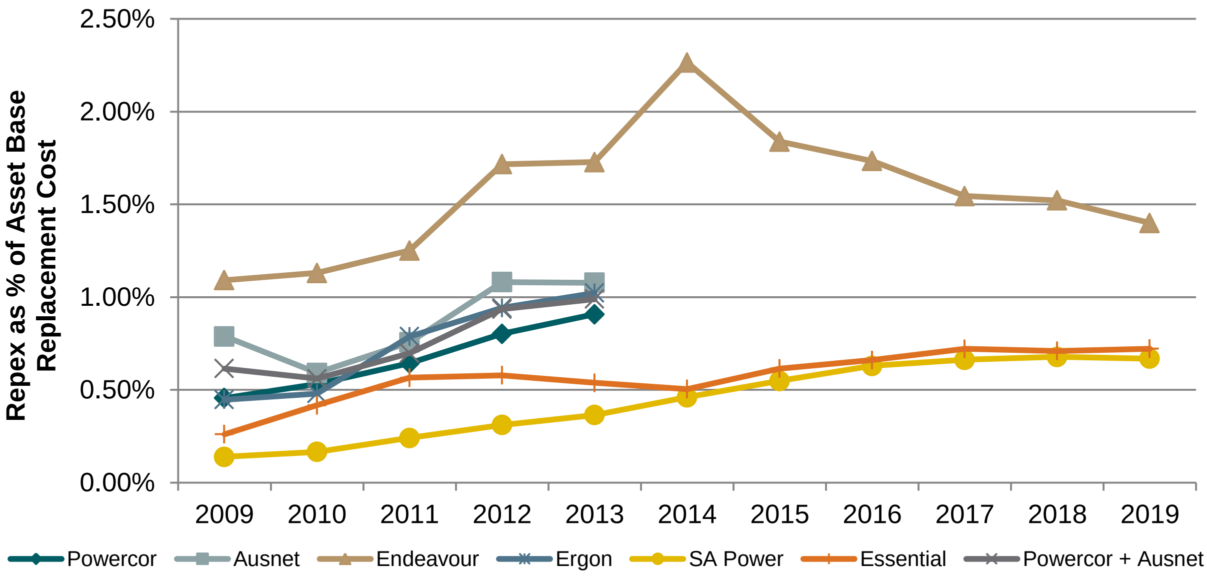

Figure 6-3: Replacement capital expenditure spend per asset base replacement cost[190,191]

Figure 6-3 highlights that Essential Energy's historic and proposed replacement capital expenditure compare favourably across the NEM. It also shows that Essential Energy's proposed replacement capital expenditure

[190] Replacement costs determined using; RIN asset quantities and the AER's NEM Benchmarked unit costs - category's included Poles, OH Conductor, UG Cable, Services, Transformers, Switchgear (including categories added by DNSP's under these headings) – where a benchmarked unit cost does not apply to DNSP listed category the DNSP's calculated (historic) unit cost is used.

[191] Annual Repex spend determined using: RIN table 2.2.1 - Poles, OH Conductors, UG Cables, Service Lines, Transformers, Switchgear and Other (DNSP listed Other – this category is mostly used by Ausgrid and Endeavour).

appears to be forecast at a reasonable level to address the emerging replacement capital expenditure demand, driven by an asset base with an already high and increasing average age.

Given Essential Energy's high calibrated asset lives and low historical replacement capital expenditure spend, it casts significant doubt on the AER's draft determination to dismiss our bottom up build from asset condition and failure history and replace it with the lowest possible outcome from a deterministic application of a repex model that is overly sensitive to reasonable sets of inputs and gives a wide variation in outputs. Essential Energy benchmarks well against similar industry peers including three distributors that the AER consider are at an efficient frontier.

The decision by the AER to reduce the Essential Energy replacement capital expenditure proposal is counterintuitive to the decision the AER applied to Endeavour Energy. Table 6-7 compares the key assets and replacement capital expenditure decisions of Essential Energy and Endeavour Energy.

Given Essential Energy's high calibrated asset lives and low historical replacement capital expenditure spend, it casts significant doubt on the AER's draft determination…

The decision by the AER to reduce the Essential Energy replacement capital expenditure proposal is counterintuitive to the decision the AER applied to Endeavour Energy.

Table 6-7: Replacement capital expenditure and assets for Essential Energy and Endeavour Energy

	Essential Energy	Endeavour Energy	% Difference
Replacement capital expenditure proposal	$856M[192]	$738.7[193]	
Replacement capital expenditure draft decision	$675M[194]	$661M[195]	+4%
Poles[196]	1,377,483	305,822	+450%
Circuit km's[197]	193,423	44,305	+436%
Distribution Substations[198]	136,125	29,721	+458%
Zone Substations[199]	413	177	+233%
Weighted Calibrated Asset Life[200]	70.3	50.4	

The average pole age on the Essential Network is ten years older than on the Endeavour Network and the Essential Energy network is broadly four times larger than that of Endeavour Energy with a similar customer base. It is incongruous given the quantum of the draft replacement capital expenditure decision for Essential Energy is only four per cent more than Endeavour that both decisions can be correct and shows the risk of accepting the results of the repex model without sense checking against a sound bottom up build.

[192] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 6: Capital expenditure*, November 2014, pp. 6-11

[193] AER, *Draft Decision - Endeavour Energy distribution determination 2015-16 to 2018-1 9- Attachment 6: Capital expenditure*, November 2014, pp. 6-11

[194] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 6: Capital expenditure*, November 2014, pp. 6-11

[195] AER, *Draft Decision - Endeavour Energy distribution determination 2015-16 to 2018-19 Attachment 6: Capital expenditure*, November 2014, pp. 6-11

[196] *2013-14 - Essential Energy and Endeavour Energy Reset RIN Table 5.2*

[197] *2013-14 - Essential Energy and Endeavour Energy Reset RIN Table 5.2*

[198] *2013-14 - Essential Energy and Endeavour Energy Reset RIN Table 5.2*

[199] *Essential Investment Case ESS_89, may 2014 and Endeavour Energy Regulatory Proposal – 1 July 2015 to 30 June 2019*, p8.

[200] Calibrated life weighted to Essential Energy's asset base quantities. Data from AER draft decision Essential Energy and Endeavour Energy distribution determination Calibrated Forecast repex models and Nutall Consulting, Report - Aurora Revenue Review, Nov 2011– Victorian data based on 2004/05 to 2008/09 period.

Risk tolerance

The AER has suggested that Essential Energy's approach to risk is overly conservative. Essential Energy suggests that this is intuitively not correct given that:

- Essential Energy has the longest weighted calibrated lives in the NEM with the exception of CitiPower, a non-comparable small underground city network. An overly conservative DNSP would have lower calibrated asset lives.
- Essential Energy's network incurs failures at higher normalised rates than Victorian DNSP's for whom reliable failure data is readily available through Energy Safe Victoria. An overly conservative DNSP would have low normalised failure rates.
- Essential Energy's pole failure rate is high by industry standards at 1:9,550 only exceeded by one DNSP. This DNSP has been the subject of multiple safety interventions by its safety regulator and is currently replacing poles in the order of four times the rate of Essential Energy.
- Essential Energy's proposed replacement programs fall well below the levels forecast by the AER's NEM benchmarked models for pole, service, transformer and switchgear replacement. An overly conservative DNSP would have high replacement rates.
- Essential Energy has a lower replacement capital expenditure spend on a per asset basis than its peer DNSPs. An overly conservative DNSP would have a high replacement capital expenditure spend per in service asset.

It does not appear logical given the facts above and as set out in Attachment 6.6 – replacement expenditure that Essential Energy's approach to risk is overly conservative. It is far more probable that Essential Energy operates at the higher end of the acceptable risk tolerance, especially when compared to other DNSP's.

> *It does not appear logical…that Essential Energy's approach to risk is overly conservative. It is far more probable that Essential Energy operates at the higher end of the acceptable risk tolerance…*

Deliverability

The AER's draft decision raises concerns with Essential Energy's ability to deliver our forecast replacement capital expenditure, despite the significant reduction in total forecast capital expenditure for the 2014-19 regulatory period compared to the 2009-14 regulatory period. Deliverability cannot be correctly assessed by looking at replacement capital expenditure only. Rather, a holistic view of capital and operating expenditure programs needs to be taken as Essential Energy's multi-skilled workforce undertakes a mixture of work activities across all program areas. As highlighted in Attachment 6.11, the volume of capital and operating activities to be delivered in the 2014-19 regulatory period is actually less than the total delivered in the 2009-14 regulatory period. Whilst replacement capital expenditure increases in the 2014-19 regulatory period, the volume of augmentation capital expenditure and customer connections drops significantly, with maintenance remaining steady. The drop in augmentation capital expenditure and customer connection activity more than offsets the increase in replacement capital expenditure.

In addition, when the proposed capital and operating expenditure programs are reviewed at the lower level of the transmission and distribution work groups within Essential Energy, Attachment 6.11 demonstrates that there is no risk to delivery. For the transmission work group, the total capital expenditure work volume drops by more than 40 per cent, whilst the work volume of the distribution work group is steady. The impact of the 7 per cent higher volume of replacement capital expenditure for the transmission work group is more than offset by the 59 per cent reduction in augmentation capital expenditure work, and therefore the move to replacement capital expenditure for the transmission work group poses no delivery issues.

The AER also indicated its concerns at the lack of a Strategic Delivery Plan being in place for the delivery of the 2014-19 replacement capital expenditure program. However, the development of a Strategic Delivery Plan is underway with the plan to be produced by the end of the financial year to coincide with the release of the AER's final 2014-19 Determination. A strategic resource demand model is nearing completion and a Strategic Resource

Planning Framework has been developed which will result in the development of an annual Strategic Delivery Plan and a quarterly update. The modelling work to date indicates that the resource demand will be within the capabilities of the current internal and external resources available and that under delivery is a low risk.

Unmodelled replacement capital expenditure

In its draft decision, the AER has accepted our initial proposal for other unmodelled capital expenditure. No revisions are necessary for categories including SCADA, network control and protection, and pole top structures that were not modelled using The Repex Model.

However subsequent to reviewing the draft decision Essential Energy has identified a number of programs where there has been no history of replacements which cannot be assessed by The Repex Model. Our revised proposal has identified that the following programs of work should be assessed as unmodelled replacement capital expenditure:

- Low Voltage UG Cable Replacement (CONSAC) - $18.89M
- Utility Blackspot Program = $7.75M
- Subtransmission Polymer Termination Replacement - $0.82M
- LV Protection Program Far West - $2.04M
- Broken Hill Generator Asset Refurbishment - $1.40M.

The total additional programs to be assessed outside The Repex Model are $30.90 million. Full details of the programs and the reasoning behind their treatment as unmodelled replacement capital expenditure are included in Attachment 6.6 – replacement expenditure.

Capitalised overheads

In our initial proposal our capital expenditure forecast contained $681 million ($2013-14) of capitalised overheads. The AER has separately assessed these overheads and rejected our forecast substituting an amount of $479 million. This amount is based on a capped allocation rate of 32 per cent based on the average actual capitalised overheads to total gross system capital expenditure over the 2009-14 regulatory period. We have not revised our initial proposal for this approach as we consider it is incorrect and contravenes Australian Accounting Standards and the AER approved CAM. Capitalised overheads are discussed in more detail in Attachment 6.4.

Australian Accounting Standards

Australian Accounting Standard AASB 116 Property Plant 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.* [201]

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.

Our proposed capitalised overheads in our proposal were calculated in accordance with our approved CAM. However in the AER draft decision the proposed allowance for capitalised overheads has been calculated using an average rate of 32 per cent of capitalised overheads to total gross capital expenditure. This proposal circumvents Australian Accounting Standard AASB 116 *Property Plant 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.

[201] http://www.aasb.gov.au/admin/file/content105/c9/AASB116_07-04_COMPjun09_07-09.pdf

Since Essential 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 Essential 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 having to assume 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 in October 2013. This was assessed by the AER and their consultants KPMG, resulting in an amended proposed CAM being submitted on 23 April 2014. In May 2014 the AER decision on our proposed CAM was as follows:

> *We consider the CAM proposed by Essential 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, Essential Energy's proposed CAM.*[202]

The approved CAM is applied in our initial proposal, and we have not sought to change the method employed at arriving at our capital expenditure forecasts. Essential Energy reiterates that their CAM is based on the Cost Allocation Principles specified in 6.15.2 of the NER and 2.2 of the AER's Guidelines and is giving effect to these principles. The CAM is provided at Attachment 6.5.

Our approved CAM notes for system capital expenditure:

> *Essential Energy's chart of accounts and systems have been established so that both opex and capex can be separately accounted for and reported in accordance with the CAM and regulatory reporting requirements. This CAM does not distinguish between capital and opex in the treatment of costs. However, each cost is identified and classified in accordance with Essential Energy's Capitalisation Policy. The allocation of costs to business segments occurs independently of whether costs are capital or operating in nature.*[203]

Shared costs or overheads are then allocated across operating and capital projects using total direct expenditure as the denominator. 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 applying a capped allocation percentage. In regards to this we note that the AER examined network, corporate and total overheads allocated to both capital expenditure and operating expenditure in its detailed operating expenditure decision (attachment 7 to the AER's draft decision). The benchmarking analysis utilised appears to indicate that Essential Energy's overheads are comparable to other DNSPs:

The AER's approach contravenes the approved CAM and assumes overheads are purely variable costs.

> *Endeavour Energy and Essential Energy however, appear to have network overhead costs that are comparable to service providers with similar densities.*[204]

Further, if a linear relationship was assumed for the PPI measures presented it appears Essential Energy would reside on or ahead of the AER's assumed "frontier". Whilst we do not support this analysis this is the extent of the AER's assessment of overheads and there appears to be no basis for a 30 per cent reduction to our capitalised overheads. In addition to this, the AER has not considered the interrelationship between capital expenditure and operating expenditure. That being the consequential outcomes on operating expenditure if an artificial cap is

[202] AER, *Final Decision – Essential Energy Revised Cost Allocation Method,* May 2014, p9.

[203] Essential Energy, *Cost allocation method,* April 2014,

[204] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 7: Operating expenditure*, November 2014, p81.

applied to what portion of overheads can be capitalised. In the absence of this consideration, Essential Energy has not been provided an opportunity to recover efficient costs.

Non-network capital expenditure

In its draft decision, the AER has accepted our initial proposal for non-network capital expenditure, so no revisions are necessary.

Demand management

Demand management is employed as an alternative to network options such as augmenting the network where it is more efficient to do so. In assessing Essential Energy's proposal the AER has decided to continue to apply Part A of the DMIA. Consistent with the F&A the AER has 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 regulatory period.

Additionally, in its draft decision the AER notes that it considered making an explicit adjustment to the system capital expenditure forecast on the basis of the demand management deferrals from the 2009-14 regulatory 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 Essential of 9.2 per cent, or approximately $106 million ($2013–14).*[205]

The AER's rationale in raising this concept is as follows:

> *The capital deferred through the targeted demand management in 2009-14 represents 9.2 per cent of Ausgrid's system capex.*
>
> *This gives a benefit cost ratio of 2.5 times its demand management investment. This result aligns with the Productivity Commission's expected demand management benefits, which estimated a medium benefit cost ratio of 2.7 for the two most relevant scenarios ("regional rollout in peaky and constrained areas", and "direct load control without smart meters").*
>
> *As such, we consider that the Ausgrid experience in demand management in 2009–14 might represent a reasonable benchmark to assess the capex that may be deferred by Essential in the 2014–2019 period.*[206]

As well as;

> *Our analysis suggests that the Essential Energy's estimate of $6 million significantly understates the amount of capex that could be deferred through efficient demand management activities. 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.*[207]

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[205] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 6: Capital expenditure*, November 2014, p79.
[206] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 6: Capital expenditure*, November 2014, p78.
[207] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 6: Capital expenditure*, November 2014, p78.

The comparison presented is highly biased, as the calculations referenced in the Productivity Commission report are based on the net present value of the combined long run marginal costs of distribution, transmission and generation, therefore they are not the equivalent of a direct capital deferral for a single NSP during the regulatory period.

It is not clear what has been included by Ausgrid or the AER in the calculations defining a capital deferral of $334 million from an $8 million investment during the 2009-14 regulatory period, however it is clear that Ausgrid's proposed investment for the 2014-19 regulatory period of $22.1 million for broad based demand management for $38 million in market benefits (10 year NPV to 2023-24) more closely aligns to Essential Energy's expectations.

It should also be noted that the figures quoted by the AER for Essential Energy represent in period, internal capital reductions only, i.e. the AER has attempted to compare the long run marginal whole of market benefits with Essential Energy's internal only benefits. When the appropriate figures are used Essential Energy anticipates market benefits of approximately $32 million for an investment of $14 million in Demand Management programs.

Essential Energy also undertakes substantial business as usual programs to reduce demand that are treated separately in the regulatory submission. These programs include business as usual load control and zone substation power factor correction. During a recent evaluation of the load control resource it was found that load control systems provide a market benefit of approximately $1.2 billion at a cost of around $13.3 million per annum, the demand reductions stemming from these systems are inherently applied to all demand forecasts and produce systemic network augmentation deferral.

As well as business as usual programs and the new demand management programs referenced by the AER, Essential Energy also devotes substantial resource toward demand management innovation – being one of the highest users of the DMIA in the NEM.

As well as business as usual programs and the new demand management programs referenced by the AER, Essential Energy also devotes substantial resource toward demand management innovation – being one of the highest users of the DMIA in the NEM.

Taking into consideration that it is not clear what has been included in the Ausgrid calculations and the amount of demand management already undertaken and continuing to be undertaken in Essential Energy's network, the discussion on quantities of demand reduction opportunities available for the 2014-19 regulatory period above and beyond those already undertaken are likely to be at levels below historical expenditure due to the changing growth conditions and reduction in growth expenditure.

Given the references used, the misrepresentation of Essential Energy's current demand management initiatives and the reduction in potential growth expenditure available to be deferred, we do not consider the use of the implied benchmark as a reasonable position. Essential Energy believes it more appropriate to rely on functional incentive schemes to ensure DNSPs are able to utilise demand management where appropriate.

Revisions to our 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 amendments we consider the AER has reasonably identified. Furthermore, setting aside the detail of the AER's capital expenditure decision, at its core the AER considers that its substitute forecast reflects the capital expenditure criteria as opposed to our proposed forecast:

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.

> *We are not satisfied that Essential Energy's total forecast capex reasonably reflects the capex criteria. We compared Essential Energy's capex forecast to a capex forecast we constructed using the approach*

and techniques outlined above. Essential Energy's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.[208]

We therefore also reviewed our proposed program and the latest available information to assess whether revisions were required. As a DNSP, Essential 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 augmentation capital expenditure programs of $18 million ($2013-14) based on VCR changes and deferred projects.
- A decrease to capital expenditure of $63 million ($2013-14) to reflect reductions to capitalised overheads due to labour productivity.
- A reduction of $29 million ($2013-14) reflecting our adoption of the AER's approach to labour cost escalation and a marginally lower actual CPI.
- An increase of $77 million ($2013-14) in capital expenditure on low mains to reflect the introduction of LiDAR technology that has identified non-compliant clearance levels; and
- A reduction of $11 million in capital expenditure based on the rephasing of our capital expenditure program.

In total we have reduced our original proposed capital expenditure of $2,574 million ($2013-14) by two per cent to $2,531 million. We consider this revised proposal clearly demonstrates that our forecast is a reasonable estimate of the costs involved in satisfying the capital expenditure objectives, criteria and factors.

The revised forecast also reflects updated real labour escalators which were provided by CEG (Attachment 6.12) and Independent Economics (Attachment 6.13) averaged with the escalators used by the AER from Deloitte, as requested by the AER in its draft decision. These calculations can be found at Attachment 6.14.

Table 6-8 outlines our revised forecast capital expenditure for the 2014-19 regulatory period.

Table 6-8: Revised forecast capital expenditure over the 2014-19 regulatory period ($2013-14, millions)*

	2014-15	2015-15	2016-17	2017-18	2018-19	Total
Growth	178	161	148	140	130	756
Asset renewal/replacement	205	212	219	216	215	1,068
Reliability and quality of service enhancement	27	31	31	31	32	154
Compliance	36	72	68	62	56	294
Non-system assets	73	51	52	44	38	257
Total network capital	520	527	518	493	471	2,529
Equity raising costs	3	-	-	-	-	3
Total Net capital expenditure	522	527	518	493	471	2,531

* Capital expenditure includes equity raising costs and is net of disposals and capital contributions.

Note: numbers may not add due to rounding.

Why our revised proposal better satisfies the capital expenditure objectives and criteria

[208] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 6: Capital expenditure*, November 2014, p18.

We do not consider the revised forecast capital expenditure is materially different from that proposed originally by Essential Energy except to the extent that it includes the LiDAR related expenditure. As such, the reasons outlined in the 'our initial proposal' section above as to why we consider our forecast satisfies the capital expenditure objectives, criteria and factors remain valid. As outlined in that section, Attachment 5.3 to our initial proposal and the 'meeting the rules' section of that 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 substitute capital expenditure. However, its decision must consider the capital expenditure 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 arise in the capital expenditure 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 capital expenditure factors in their entirety.
- Identify how the DNSP could manage their obligations over time in a sustainable manner.

In their System Capex and Maintenance Prudency 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.*[209]
>
> *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.*[210]

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 capital expenditure 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.

Our original and revised forecasts…seek to strike a balance between sustainably reducing costs and maintaining safety and network performance.

Further, the AER has not considered what a sustainable level of capital expenditure 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 are maintained it has not considered how this can be achieved within the draft decision allowances for the 2014-19 regulatory period.

[209] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p2
[210] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p53

The consequence of the AER's 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:

The consequence of the AER's decision is that it does not provide a sufficient allowance to maintain the current level of services to our customers.

- Take more risks with our operations. Ultimately this will lead to increased probability of safety incidents and deterioration in reliability. Further, there is a long term cost impost from deferring necessary expenditure.
- Fail to service customer growth.
- Reduce the quality of our customer services and safety performance.

We do not consider this 'boom and bust' regulatory framework is in the long term interests of customers. It is also contrary to the customer feedback we have received which clearly indicates the majority of our customers find it unacceptable to accept reduced service levels in exchange for reductions in network charges.

We do not consider this 'boom and bust' regulatory framework is in the long term interests of customers [and] is also contrary to the customer feedback we have received…

We consider that the AER's decision to reduce capital expenditure and not properly account for capital expenditure/operating expenditure trade off costs would lead to a reduction in service standards, which would then require an adjustment to the STPIS targets. Instead the AER has set STPIS targets based on improved reliability performance. There is no basis for this approach as outlined in Attachment 4.2 to this revised proposal. In the context of this section we consider this provides further evidence the AER has not made a reasonable or informed decision when setting a substitute capital expenditure forecast.

We also refer the AER to a statement prepared by John Hardwick, Group Executive Network Strategy (Attachment 6.15), which provides further information on the outcomes of the prioritisation process.

For the reasons outlined above we contend that our revised proposal represents a more reasonable estimate than the AER's substitute amount of the efficient costs of meeting the capital expenditure objectives and criteria.

We consider that the AER should accept our revised forecast capital expenditure for the reasons discussed above. The AER must determine a forecast capital expenditure that reasonably reflects the capital expenditure criteria having regard to the capital expenditure factors. The capital expenditure criteria that must be reasonably reflected are:

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

The capital expenditure criteria and the requirement for the AER to consider the individual circumstances and actual costs of Essential Energy are discussed above.

Given the inherent requirements on Essential Energy to supply electricity safely, legally and reliably, any reduction in capital expenditure must be carefully, considered, planned and managed. This careful management and planning has been reflected in the efficiency programs that Essential 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.

7. OPERATING EXPENDITURE

> We believe the AER's benchmarking report is fundamentally flawed, lacks rigour and fails to enable appropriate engagement with the DNSPs.
> We propose to address labour productivity via natural attrition over the five year regulatory period.
> The AER's draft determination implies significant negative impacts on Workplace Health & Safety, customer safety and reliability .

Summary

We are proposing a revised operating expenditure program of $2.3 billion ($2013-14) for the 2014-19 regulatory period to support our business activities and maintain the reliability, safety and security of our distribution system. This is marginally lower than the forecast operating expenditure in our initial proposal.

In our initial proposal, we provided the AER with information to demonstrate the efficiency of our forecast operating expenditure. Our expenditure sought to address the expectations of our customers by providing safe, reliable and affordance services in the 2014-19 regulatory period. A key element of our proposal was to incorporate substantial efficiencies from our network reform program.

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 deterministic use of benchmarking analysis.

We have sought to reflect on whether revisions are required to incorporate the matters raised in the AER's draft decision and its reasons for it. We have retained most elements of our initial proposal rather than revise for the AER's draft decision 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 operating expenditure. Further, we consider that the substantive issues raised by the AER in respect of labour practices, vegetation management and our redundancy costs have not raised issues that require revision of our proposal.

We have revised our proposal for matters that the AER has reviewed in its draft decision, but these mostly relate to updates for the latest information and data rather than concerns raised by the AER's decision. These include:

- 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 gathered through LiDAR since the submission of our initial proposal.
- Asset rectification tasks gathered through LiDAR result in increased operating expenditure due to additional pole top defects being identified.
- The AER found that our proposed operating expenditure contains material inefficiencies. We have examined the latest data to establish the impact of our efficiency programs in the 2014-19 regulatory period. Based on this analysis we have found that our staff attrition rates are higher than we previously forecast in our initial proposal. This results in a labour productivity improvement of 22.6 per cent by the end of the 2014-19 regulatory period.
- Increase in the business transformation costs from reallocated labour associated with a reduction in the capital program.
- We have updated labour cost escalators by adopting the AER's approach from its draft decision and using the most current data from CEG and averaging this with the AER's escalators from the draft decision provided by Deloitte.

Having had regard to the AER's decision, Table 7-1 provides our revised forecast operating expenditure for each year of the 2014-19 regulatory period, compared to the initial proposal and AER draft decision.

*Table 7-1: Forecast standard control operating expenditure over the 2014-19 regulatory period ($ million, 2013-14)**

	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Initial proposal	464	465	461	467	477	2,334
AER draft determination	281	284	287	291	295	1,440
Revised proposal	498	491	455	459	428	2,331

* Includes debt raising costs and DMIA.

This Chapter encompasses the following sections:

> The framework in the Rules and NEL that the AER must apply in making its constituent decision for operating expenditure.

> A summary of how our initial proposal addressed the framework, including how our proposed operating expenditure was set to achieve the operating expenditure objectives, and how this satisfies the operating expenditure criteria with regard to the factors.

> A summary of the AER's draft decision including its assessment methods, its reasons for rejection, its basis for substitution and how it sought to address the Rules framework.

> 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 operating expenditure criteria. We show that the AER has misinterpreted its powers following amendments to the Rules and Law in 2012. This has manifested itself into three ways that the AER has been misdirected in making its decision:

  - 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 account for the operating expenditure 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 of its decision on our operations.

> 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.

> In reviewing the matters raised in the AER's draft decision, we have examined whether any revisions are required to incorporate new information or data since submitting the initial proposal. We set out our revisions to the initial proposal including vegetation management, updates based on the latest data on labour productivity, and updates to real cost escalators. Finally, we show how our revised proposal better satisfies the operating expenditure criteria in relation to the operating expenditure objectives, compared to the AER's decision. We undertook a review of our activities and show that the AER's proposed cut would reduce our ability to maintain a safe network, undertake prudent vegetation management, support our system activities, and deliver on our corporate obligations.

Framework for AER's decision

The Rules require the AER to make a number of constituent decisions as part of its distribution determination. Clauses 6.12.1(3) and 6.12.1(4) of the NER relate to the AER's decisions on the forecast capital expenditure and forecast operating expenditure proposed by a DNSP in its building block proposal. The AER either:

(i) acting in accordance with clauses 6.5.6(c) and 6.5.7(c), accepts the total of the forecast operating expenditure and capital expenditure 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) and 6.5.7(d), does not accept the total of the forecast operating expenditure and capital expenditure 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 operating expenditure and capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital and operating expenditure criteria, taking into account the capital and operating expenditure 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 of these areas is discussed below.

Objectives, criteria and factors

The rules set out a framework such that Essential Energy is required to propose total operating expenditure that Essential Energy considers is needed to produce the outputs or outcomes that are encapsulated in the Rules. These outputs/outcomes are specified in clauses 6.5.6(a) and 6.5.7(a) of the Rules and are termed the operating and capital expenditure objectives (together expenditure objectives).

Clauses 6.5.6(a) and 6.5.7(a) of the NER require Essential Energy to include in its building block proposal the total forecast operating expenditure and capital expenditure for the 2014-19 regulatory period which Essential Energy considers is required to achieve each of the expenditure objectives.[211]

The AER is required to make a decision on the total forecast expenditure proposed by Essential Energy. The Rules provide that the AER must accept the forecast expenditure included in Essential Energy's building block proposal if the AER is satisfied that the total forecast expenditure reasonably reflects the expenditure criteria. These expenditure criteria are:

- The efficient costs of achieving the operating expenditure objectives.
- The costs that a prudent operator would require to achieve the operating expenditure objectives.
- 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 Essential Energy's proposed total forecast expenditure reasonably reflects each of the expenditure criteria, the AER must have regard to the expenditure factors.[212]

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[211] 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.

[212] 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)

Changes to the NER in 2012

As part of the 2012 Rule change on the Economic Regulation of NSPs, the AEMC reviewed the decision making framework for operating expenditure. The AEMC largely maintained the existing framework in the Rules that was applied in making our 2009-14 final distribution determination. This included maintaining the structure of the objectives, criteria and factors.

At the time, the AEMC 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:[213]

> *The proposal is necessarily the procedural starting point for the AER to determine a capital expenditure or operating expenditure allowance.*

- The assessment process must start with a DNSP's proposal - The proposal is necessarily the procedural starting point for the AER to determine a capital expenditure or operating expenditure 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.
- 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 is 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 NSP's knowledge of its own network, then the AER should justify its conclusions by reference to it, in the same way it should in regard to any other submission of probative value.
- The AER's assessment techniques in making its analysis are not limited – The NSP'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 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 capital expenditure or operating expenditure. The AER, whenever it determines a substitute for a NSP's proposal, is not constrained by the capital expenditure and operating expenditure 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 NSPs, the AEMC provided for the development of an expenditure forecast assessment guideline. The purpose of this

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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.

[213] AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012.

Guideline is for the AER to specify the approach it proposes to use to assess the expenditure forecasts that form part of a DNSP's 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 on the approach the AER utilises in assessing a DNSP's forecast expenditure. Ultimately, this Guideline should support the achievement of the operating expenditure objectives and criteria and align to the operating expenditure factors. During the AER's development of the guideline Essential Energy, and the NSW DNSPs, noted their concerns with the proposed guideline:

During the AER's development of the guideline Essential 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.* [214, 215]

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 a DNSP to inform the AER of the forecasting method it proposes to use to prepare the expenditure forecasts that form part of its regulatory proposal. This submission must occur six months prior to the submission of a DNSPs regulatory proposal. We consider this is to provide the AER with further clarity as to the forecasting method 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.

We consider in that the combined 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.

Interdependency of the framework

As outlined above, the framework contains a number of elements that provide guidance and direction to DNSPs and the AER. We consider the 2012 rule change did, in some way, reduce the necessity or obligation on the AER to assess the material provided at a granular level to the extent that the AEMC clarified the intent of the framework.

In doing so, the AEMC did however introduce a valuable and necessary cross check in the determination process. This was to ensure that when aggregated, the sum of the detailed decisions and assessments made by the AER also delivered an overall outcome that is logical and reasonable in the circumstances. Clearly the reverse also applies such that a decision that appears erroneous overall should result in further detailed analysis.

…[a necessary cross check] was to ensure that when aggregated, the sum of the detailed decisions and assessments made by the AER also delivered an overall outcome that is logical and reasonable in the circumstances.

[214] NSW DNSPs, *Submission on AER expenditure forecast assessment guidelines issues paper*, 14 March 2013.
[215] NSW DNSPs, *Joint Submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013.

The amendments did not provide a criterion to assess whether an overall revenue allowance achieves the NEO. We consider this is because the guidance for this already exists within the decision making framework provided in the NER. The change is to avoid the occurrence of sub-optimal decisions being made when combining accurate and sound decisions at the granular level.

As such, these amendments to the NER and NEL do not permit the AER to make a decision solely at the higher level, that is the total revenue and expenditure plans associated with this. The overall assessment and detailed assessment are complimentary and therefore flawed in the absence of one another. That is to say, it cannot be concluded that a decision achieves the NEO at the overall level without reference to the methodological analysis and application of the expenditure factors.

Our initial proposal

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 operating expenditure 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 operating expenditure. We showed that in the lead up to the 2009-14 determination, Essential Energy was entering a period of renewal in the network to address legacy issues from under investment in the past. Our proposed operating expenditure for the 2009-14 regulatory period recognised that our operating expenditure would need to increase in response to these circumstances.

> *…in the lead up to the 2009-14 determination, Essential Energy was entering a period of renewal in the network to address legacy issues from under investment in the past. Our proposed operating expenditure for the 2009-14 regulatory period recognised that our operating expenditure would need to increase in response to these circumstances.*

At the time of the 2009-14 determination, the AER scrutinised our proposed operating expenditure in great detail, assessing our operating expenditure categories. The AER made minor reductions to our proposed operating expenditure based on its thorough assessment, accepting the need for increased investment with the full knowledge of the associated increase in network charges. The AER also implemented a very powerful incentive in the form of the EBSS on Essential Energy to incentivise reductions in operating expenditure over the period.

Based on our response to the incentives, we considered that our actual costs in 2012-13 were an efficient starting point from which to develop an operating expenditure forecast. We then considered the drivers of costs in the 2014-19 regulatory period relative to our actual costs, with regard to our regulatory obligations and operating environment.

A central aspect of our proposal was to show how the proposed operating expenditure met the long term interests of our customers. We demonstrated the efficiency initiatives we had introduced in the 2009-14 regulatory period, which had led to significant cost savings. We also showed how we had considered the level of efficiencies we could achieve in our circumstances, and how we had incorporated these into our forecasts to improve affordability for our customers.

Together with our contextual description, we also sought to demonstrate how our forecast of operating expenditure achieved the operating expenditure objectives, and satisfied the operating expenditure criteria in the Rules with regard to the operating expenditure factors. Through Attachment 5.3 of our initial proposal we summarised how our proposal met the framework under 6.5.6(a) of the Rules.

Achieving operating expenditure objectives

Essential Energy included in the building block proposal a total forecast operating expenditure for the 2014-19 regulatory period that Essential Energy considered it required to carry out the necessary activities so as to achieve each of the operating expenditure objectives listed in clause 6.5.6(a) of the Rules. This total forecast operating expenditure is made up of 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 operating expenditure objectives.

We outlined the components of our proposed total forecast operating expenditure for the 2014-19 regulatory 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 and of undertaking the activities necessary to deliver the outcomes specified by each of the expenditure objectives.

System maintenance activities and costs

Maintenance operating expenditure is required to undertake various activities on Essential Energy's electrical network. These activities, hence associated cost, are critical to achieve all four operating expenditure 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), power line to ground and vegetation clearances, thermography of power line and substation structures, and non-destructive testing of power transformers and switchgear. These activities are critical in assessing the current state of distribution equipment and establishing network safety, risks and liabilities that ultimately determine the maintenance work plan. Chemical preservatives are generally applied to wood poles at the time of inspection. Inspection cycles are based on associated risks and utilise both ground inspections and aerial patrols. Inspection criteria are detailed in asset management policies and procedures. All private overhead power lines are inspected on the same basis. The inspection of customer connection equipment ensures compliance with relevant legislative and safety requirements.

Maintenance and repair

This cost category covers all maintenance and repair activities on network assets. This is a stable, on-going maintenance program. Components include maintenance and repair of distribution power line equipment, damaged or inoperable switchgear fuse replacement, distribution substations, and customer service mains.

Vegetation management

Due to the wide expanse and overhead nature of Essential Energy's distribution network, vegetation management is the most significant operating expenditure category in dollar terms. Our policy is to clear vegetation from power lines in accordance with ISSC3[216]. Compliance with this policy is a critical control measure associated with management of bushfire risk. The majority of vegetation management work is generated and undertaken in one of two ways:

Due to the wide expanse and overhead nature of Essential Energy's distribution network, vegetation management is the most significant operating expenditure category in dollar terms.

- A systematic and regular program of vegetation clearance work carried out on power lines based on a prescribed cutting cycle (referred to as cyclic vegetation clearance).
- Spot cutting of defects arising from annual aerial patrols carried out to remove higher risk, individual incursions of vegetation into the clearance envelope.

Spot trimming removes risk quickly but it is not the most efficient measure in the long-term. Our strategy is to keep vegetation to allowable standards by moving to a mainly cyclic vegetation clearing process over a period of time. Recent action has been taken to reduce spot trimming backlogs and shift resources into cyclic trimming. We expect the number

Our strategy is to keep vegetation to allowable standards by moving to a mainly cyclic vegetation clearing process over a period of time.

[216] Industry Safety Steering Committee, *ISSC 3 Guideline for Managing Vegetation near Power Lines*, December 2005.

of problem areas detected through our annual aerial inspections to be significantly reduced in future.

Notwithstanding the above, one major improvement initiative that will, in the long-term, deliver sustainable service improvement outcomes is the Aerial Patrol and Analysis (AP&A) including the LiDAR inspection program. Whilst this program is new to Essential Energy, it has been used with success by other NSW DNSPs using similar programs to examine the state of their networks. The experience of all NSW DNSPs shows that the program will deliver benefits across several areas of the business, but principally in the areas of more effective and accurate identification of defective pole and pole-top hardware, low-hanging conductors, and vegetation encroachment.

The initial stage of the program, which has examined approximately 28 per cent of the rural distribution network, has identified a large volume of defects and potential hazards to the network that had previously remained unidentified by traditional patrol and inspection techniques. These defects all present risks of varying degrees to public and Essential Energy personnel safety, network reliability, and bushfire risk. The unique perspective provided by aerial high-definition photography and accurate LiDAR range-finding and measurement is providing a wealth of reliable data concerning the condition of network assets, which indicates that many areas of the network are in a worse and more aged condition than previously believed.

The total indicative forecast for the 2014-19 regulatory period now includes an additional expenditure allowance required to undertake additional maintenance associated with the increased volumes as a result of the AP&A program and also includes efficiencies achieved through a number of strategic reform initiatives, including improved contractual arrangements. This ensures an appropriate end-to-end management capability and an adequate vegetation management system as the key enabler. This will deliver the best long-term cost outcome whilst also managing the risks associated with vegetation encroachment on power lines. Forecast work volumes have been determined by statistically significant sampling across the network. Our analysis involves the classification of vegetation density classes and estimating associated unit costs.

Emergency response

This covers fault and emergency repair and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. On notification of a customer supply interruption, Essential Energy dispatches field employees to address the fault.

Other network costs

The main areas of expenditure are network operating activities including supply interruptions and network control, maintenance and repair of zone substations, network divisional operating expenditure, and customer service.

In addition to the forecast operating expenditure that Essential Energy proposed, the AER also allows a DMIA and debt raising costs. The AER has accepted these costs as legitimate operating expenditures that are required to meet the operating expenditure objectives.

Satisfying the operating expenditure criteria with regard to the operating expenditure factors

Our initial proposal was accompanied by expert economic opinion from NERA Consulting on how to interpret the operating expenditure criteria in the Rules, and on how to demonstrate that the forecast operating expenditure 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 operating expenditure factors that the AER must consider in deciding whether it is satisfied that the forecast expenditure reasonably reflects the expenditure criteria.

Methodology employed by Essential Energy to derive forecast operating expenditure

In our initial proposal we demonstrated that we have a fit for purpose approach to forecasting our operating expenditure for the 2014-19 regulatory period.

Our initial step in developing our forecast operating expenditure for the 2014-19 regulatory period was to disaggregate our actual costs in 2012-13 (most recent actual 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 operating expenditure objectives (for example, maintenance, network control and inspections).

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 operating expenditure. As we note in the following section, we considered that our performance against the target set by the AER in 2009-14 provided demonstration that the starting point was efficient.

> *…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 operating expenditure requirement in the 2014-19 regulatory 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 operating expenditure activity. This included legislative changes, known compliance issues with our existing standards, and changes to our operating environment. For example, with vegetation management and maintenance in this revised proposal, LiDAR has identified compliance issues with ISSC3[217], which will result in an increase to our costs in the 2014-19 regulatory period to achieve the operating expenditure objectives.

We also considered broader factors in our environment that would influence our operating expenditure in the 2014-19 regulatory period. We considered that a top down approach would provide a more accurate estimate of the resultant change in operating expenditure from these drivers of expenditure. In particular we took into account two important elements of the operating expenditure criteria through this approach:

- Demand – We calculated the impact of increased growth capital expenditure through our asset growth escalator.
- Input costs - We calculated the expected change in real costs of inputs used in delivering our operating expenditure activities.

Our forecasting approach also explicitly considered the efficiencies we could achieve in the 2014-19 regulatory period. This recognised that a prudent business is continually seeking to implement efficiencies when opportunities arise. Our forecast 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 staff, 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

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[217] Industry Safety Steering Committee, *ISSC 3 Guideline for Managing Vegetation near Power Lines*, December 2005.

operating expenditure is reflective of the efficient costs that a prudent operator would require to achieve the operating expenditure objectives. This process gave us confidence that our total forecast operating expenditure would reasonably reflect the operating expenditure criteria and ensures that the NEO and the Revenue and Pricing Principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient costs we expect to incur in the 2014-19 regulatory period.

Our initial proposal also identified the relevant operating expenditure factors that align to assessing the prudency of our forecasting approach.

… we identified that reductions in replacement capital expenditure will degrade the health of assets on the network, and increase the efficient maintenance costs.

> Substitution possibilities between operating and capital expenditure (expenditure factor 7). Our forecasting process considered the consequential impact of efficient capital investment on our future operating expenditure requirements. For instance we identified that reductions in replacement capital expenditure will degrade the health of assets on the network, and increase the efficient maintenance costs. We also considered how IT and property capital expenditure may impact on operating expenditure for these activities.

> The extent to which Essential Energy has considered and made provision for efficient non network alternatives – We considered the extent to which demand management activities taken to defer capital expenditure would impact on operating expenditure in the 2014-19 regulatory 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 customers as identified by the DNSP in the course of its customer engagement (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 operating expenditure meets the criteria.

Operating expenditure factor 5 states that the AER must have regard to the actual and expected operating expenditure of the DNSP during any preceding regulatory 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 initial proposal. We showed that we performed better than the targets that the AER had determined were efficient, as can be seen in Figure 7-1.

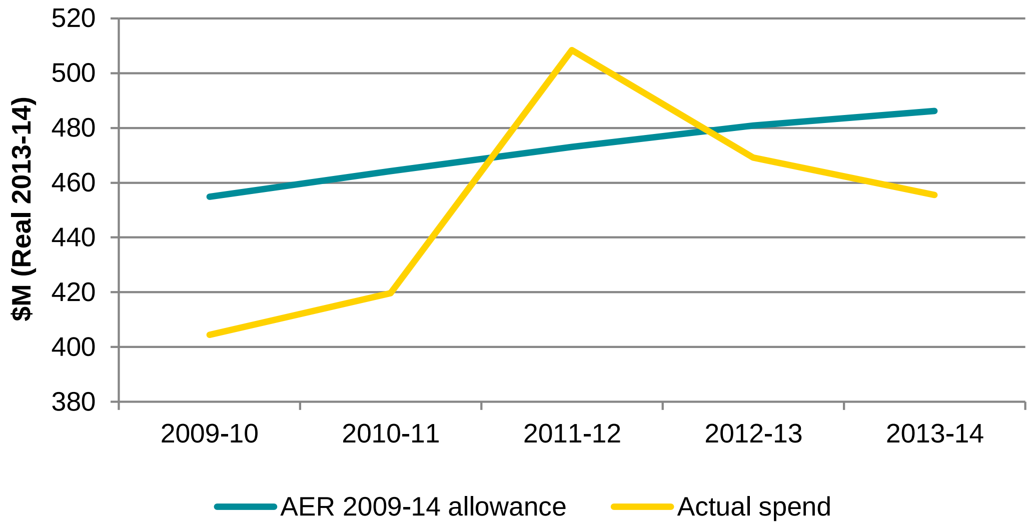

*Figure 7-1: Total operating expenditure 2009-10 to 2013-14 ($ million, 2013-14)**

* Includes DMIA and debt raising costs.

This performance was achieved through the implementation of a number of cost saving initiatives. It has set a solid platform for Essential Energy in ensuring that the forecast operating expenditure for the 2014-19 regulatory period reasonably reflects the efficient costs that a prudent operator would need to achieve the operating expenditure objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

Operating expenditure 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 operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory 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 by the NER. This failure delayed the publication of the report by almost two months and resulted in no consultation or engagement with Essential Energy on how the AER would use the report to assess (and apparently determine) forecast operating expenditure. This is unsatisfactory, and prejudicial to the interests of Essential Energy and inconsistent with the NER.

In Attachment 5.4 of our initial proposal, we submitted a comprehensive report on the limitations and role of benchmarking as a partial indicator. 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 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 its inherent limitations as a tool.

…[benchmarking] should not be used to reject a DNSP’s proposal, or as a basis to substitute the forecast, given its 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 operating expenditure factor 9, which is the extent to which forecast expenditure relates 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.

AER's draft decision

In its draft determination, the AER made a constituent decision to reject our proposed operating expenditure of $2,334 million, and substitute an amount of $1,440 million for the 2014-19 regulatory period, which was 38 per cent lower.

AER's methodology for assessing our proposal

The AER noted that its assessment method to review our proposal was consistent with its Expenditure Forecast Assessment Guideline 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 operating expenditure is materially different to our estimate and there <u>is no satisfactory explanation</u> 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* [emphasis added].[218]

How the AER developed its alternative forecast

The AER's approach to forming an alternative estimate of operating expenditure 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 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.*
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*

[218] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p12.

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. [219]

The AER noted that underlying its approach are two general assumptions: First that the efficiency criterion and the prudence criterion in the NER are complimentary, and second, that actual expenditure was sufficient to achieve the expenditure objectives in the past.

The AER's decision to reject proposed expenditure

The AER's decision clearly reflects its approach to use its alternative forecast as the reference point for assessing whether our proposed forecast operating expenditure satisfied the operating expenditure criteria. The AER stated:

> *We are not satisfied that Essential Energy's total forecast opex reasonably reflects the opex criteria. We compared Essential Energy's opex forecast to an opex forecast we constructed using the method outlined above. Our estimate is of the efficient opex a prudent operator would require to achieve the opex objectives. Essential 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 Essential Energy's total opex forecast with our total opex forecast.* [220]

The AER's findings were based on the steps of its review set out in its assessment method. 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 operating expenditure criteria. Finally the AER considered our proposed step changes, and determined that these did meet the operating expenditure criteria.

AER's findings on base year

The AER stated that it tested the efficiency of Essential Energy's base operating expenditure in 2012–13 using a number of different assessment techniques. Based on these tests, the AER was not satisfied it represents operating expenditure incurred by an efficient and prudent service provider. The AER's findings are described in Table 7-2.

Table 7-2: AER draft determination estimate of efficient base year operating expenditure ($ million, 2013-14) [221]

	Operating Expenditure
Proposed base operating expenditure (adjusted)	414.9
Substitute base operating expenditure	**270.8**
Difference	144.1
Percentage operating expenditure reduction	**34.7%**

It can be seen from the analysis that the AER's method to determine our base year operating expenditure relates to benchmarking analysis. Five of the seven assessment methods relate to benchmarking analysis, or adjustments to reflect benchmarks. The AER's conclusions were as follows in relation to its findings from benchmarking analysis:[222]

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219 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p12-13.

220 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p16.

221 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p28.

222 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p18-19.

- Economic benchmarking - Despite differences in the techniques the AER used, all benchmarking techniques show Essential Energy performs about half as efficiently as the most efficient service providers in the NEM (CitiPower and Powercor).
- Partial Productivity Indicator (PPI) Benchmarking - PPIs corroborate its economic benchmarking evidence. Essential Energy appears to have higher costs than most other service providers on total network cost per customer and total operating expenditure per customer.
- Category analysis benchmarking - In general, Essential Energy appeared to have higher costs relative to most of its peers for the categories the AER examined.
- The AER found some operating environment differences that it considered affect Essential Energy's operating expenditure performance in economic benchmarking. Overall, the AER considered a ten per cent allowance for operating environment differences is reasonable.
- Direct comparison - shows that Essential Energy incurred similar total operating expenditure to the sum of Powercor and SA Power Networks (SAPN) over the past eight years, despite Essential Energy serving only 54 per cent of customers and operating a network that experiences only 47 per cent of the peak demand of Powercor and SAPNs' combined networks.

A significant proportion of the AER's benchmarking analysis and conclusions ignores the fact that Essential Energy operates a network which is 18 per cent longer than the combined length of Powercor and SAPNs' circuits, and covers an area that is approximately two and a quarter times the combined area of Powercor and SAPN.

…Essential Energy operates a network which is 18 per cent longer than the combined length of Powercor and SAPNs' circuits, and covers an area that is approximately two and a quarter times the combined area of Powercor and SAPN.

The AER also stated that it undertook a review of our proposal. The AER stated:

> *…evidence that Essential Energy has historically had some inefficient practices is evident from its regulatory proposal and subsequent submissions. For example, Essential 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.* [223]

The final technique that the AER used to assess our proposal was a review of labour force practices. It referred to its consultant's report from Deloitte Access Economics (Deloitte) which found that Essential Energy's labour and workforce management issues meant the base year would not likely represent efficient costs.

The AER noted that Deloitte considered that Networks NSW (NNSW) had identified significant efficiency improvements with the NSW service providers but noted the reforms are only in their early stages. Deloitte concluded it is therefore likely that the full benefits of the current NNSW efficiency programs will not be realised until the 2014-19 regulatory period.

The AER also stated that Deloitte considered the network reform program has not looked beyond the three NSW businesses for opportunities to improve efficiency, supporting Deloitte's' view that Essential 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 operating expenditure captures the forecast year on year change in efficient base operating expenditure. Specifically, it accounts for forecast changes in output levels, prices and productivity (such as economies of scale). The AER considered that these three operating expenditure drivers

[223] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p18.

should account for the main reasons why the efficient base level of operating expenditure 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 noted that its forecast output change is a top down approach based on the annual percentage change in Essential 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 Essential 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 operating expenditure objectives.

The AER also used a different method to forecast labour and materials cost changes. The AER based the forecast change in labour costs on an average of our forecast method using labour escalators from CEG and their own method of using labour escalators from Deloitte. The AER decided not to apply any real escalation to the cost of materials.

AER's findings on step changes

The AER assessed our proposed step changes (i.e.: change in costs not related to a rate of change). The AER stated that it did not include any step changes in its alternative operating expenditure forecast.

The AER did not accept our step changes for accounting treatment changes, network reform program implementation costs and other costs as it believed a prudent and efficient service provider would not require a step change in operating expenditure for these cost drivers.

The AER also did not consider that vegetation management, reclassified ancillary network and metering services, and actuarial adjustments for long service leave were step changes.

Debt raising costs

The AER did not accept our level of debt raising costs and instead determined a lower amount due mainly to changes in the projected RAB value through the 2014-19 regulatory period.

AER's substitute allowance

Having rejected our proposal, the AER's substitute allowance was based on its own alternative estimate. In total the AER's substitute operating expenditure was $1,440 million compared to our proposal of $2,334 million.

The AER's method to derive a substitute was as follows:

- First, the AER considered an efficient service provider would need less base operating expenditure than a forecast based on Essential Energy's actual operating expenditure in 2012–13, and that it was appropriate to adjust Essential Energy's base year operating expenditure. On the advice of its consultant Economic Insights (EI), 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 Essential Energy's efficiency to a weighted average of all networks with efficiency scores above 0.75 (CitiPower, Powercor, United Energy, SAPN and AusNet) 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 nine per cent lower than the most efficient service provider predicted by the Cobb Douglas SFA model alone.[224]

[224] The AER noted that the transfer of operating expenditure 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 Essential Energy's actual operating expenditure when comparing it to the operating expenditure incurred by benchmark efficient service providers.

- The AER provided a further ten per cent allowance for those operating environment differences not completely captured by their preferred benchmarking model.

A more detailed explanation of the AER's allowance calculation is shown in Tables 7-3 and 7-4.

Table 7-3: Derivation of Essential Energy's efficient base year operating expenditure ($ million, 2013-14)

Step 1: Benchmarking and AER's calculations on benchmarking output[225]		
Determine Essential's score from benchmarking	54.9%	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 = 0.862/1.1 = 78.4%
Calculate implied operating expenditure reduction to reach efficiency target (i.e. gap to the efficient frontier)	**30%**	= 1- (Essential eff score / target) = 1-(54.9/78.4) =30%
Step 2: Construct theoretical 'substitute base year' operating expenditure[226]		
Calculate average of 8 years of operating expenditure from 2006 –13 (inclusive)	$352.46m	= average ('operating expenditure quantity') from RIN data, where 'operating expenditure quantity' is past years' operating expenditure in $FY13 = 352.46
Calculate the implied operating expenditure reduction to move to a theoretical efficient level	$105.63m	= 352.46 *0.3 [from step 1 above) =105.63
Reduce this by the implied operating expenditure reduction to make it 'efficient average operating expenditure'	$246.83m	= average ('operating expenditure quantity') – implied operating expenditure reduction = 352.46 -105.63 =246.83
Escalate average operating expenditure to create an efficient 2012-13 operating expenditure to account for output growth during the 2006-13 period ('substitute base operating expenditure' in spreadsheet)	$261.74m	= average efficient operating expenditure * composite growth factor[227] =246.83*(1+0.0604)
Express 'substitute base operating expenditure' in 2013-14 dollars	**$270.83m**	= 261.74 * CPI index =261.74 * 1.035 =270.83m

[225] AER, *Draft Decision Essential Distribution - Opex base year adjustment draft decision - November 2014.xls.*
[226] AER, *Draft Decision Essential Distribution - Opex base year adjustment draft decision - November 2014.xls.*
[227] This incorporates output growth base on customer numbers, circuit length, ratcheted maximum demand and a small factor for the amount of underground network.

Step 3: Construct theoretical 'efficiency adjustment'[228]		
Adjust Essential's reported base year operating expenditure (2012-13) to allow comparison (adjust for CAM and service classification changes and remove DRC)	$400.97m	= total operating expenditure – DRC + CAM adjustment uplift – costs related to service classification change =461.04m – 0.29m –59.78m =400.97m
Express Essential's adjusted base operating expenditure in 2013-14 dollars	$414.9m	=400.97m * CPI index =400.97m * 1.035 =$414.9m
Calculate the difference between the 'substitute base operating expenditure' and Essential's adjusted base year operating expenditure (in 2013-14 dollars)	$144.07m	= Essential's adjusted base operating expenditure - substitute base operating expenditure =414.90m – 270.83m (from step 2 above)
Express as a percentage **'efficiency adjustment'**	**34.72%**	144.07/414.90 =0.347
Step 4: Applying the theoretical 'efficiency adjustment' - The AER's calculation of operating expenditure base year and forecast for subsequent years, using equations in Expenditure Assessment Guideline[229]		
Applies the AER's forecast 'base, step, trend' operating expenditure 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 operating expenditure in the final year of the preceding regulatory period*		
alculate, estimated final year operating expenditure , *A_f* =* $F_f - (F_b - A_b) + non\text{-}recurrent\ efficiency\ gain_b$ F_f is operating expenditure allowance for the final year (2013-14) F_b is operating expenditure allowance for base year (2012-13) A_b is the actual operating expenditure in base year (2012-13)	$481.80m	12/13 actual operating expenditure – DRC costs =460.75m ($2012-13) ***$A_b$***, 12/13 actual operating expenditure – DRC costs =476.75m ($2013-14) ***$F_b$*** Operating expenditure allowance for 2012-13 =477.61m ($2013-14) ***$F_f$*** , Operating expenditure allowance for 2013-14 =482.65m ($2013-14) Non-rec. eff. gain = 0 **A_f*** =482.65 – (477.61 – 476.75) =481.80m
Adjust A_f* (final year operating expenditure) for CAM and service classification changes	$419.94m	A_f* - CAM adj uplift – costs related to service classification change =481.80m – 61.86m = 419.94m
Calculate the operating expenditure reduction using the '***efficiency adjustment'*** from benchmarking	-$145.82m	Operating expenditure adjustment = final year operating expenditure * efficiency adjustment =419.94m * **0.3472 (from step 3 above)** =145.82m
Calculate efficiency adjusted final year operating expenditure – a theoretical efficient operating expenditure in 2013-14	**$274.12m**	Theoretically efficient final year operating expenditure = Actual final year operating expenditure - 145.82m = 274.12m
Calculate operating expenditure 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) =(326.5*(1+0.022)*(1*1.018)+7 = **$337.5m** (see other years below)		

[228] AER, *Draft Decision Essential Distribution - Opex base year adjustment draft decision - November 2014.xls.*

[229] AER, *Draft Decision Essential Distribution determination - Essential 2014 - Opex model - November 2014.xls.*

Table 7-4: Forecast operating expenditure for the 2014-19 regulatory period based on 'benchmarked' base year.

	2014-15	2015-16	2016-17	2017-18	2018-19	Comment
Benchmark adjusted final year operating expenditure, Af*	**274.12 (from step 4 in table above)**					
Rate of change: AER output growth forecast	1.6	2.8	3.8	4.8	6.0	Based on only 3 cost drivers with weightings derived from historic average trends
Rate of change: AER price growth forecast	1.5	3.0	5.4	8.2	10.7	Average of Independent Economics and Deloitte Access Economics forecasts
AER's SCS operating expenditure forecast	**277.3**	**279.9**	**283.3**	**287.1**	**290.8**	

The AER was satisfied that its substitute base operating expenditure forms the appropriate starting point for total forecast operating expenditure that reasonably reflects the operating expenditure criteria. The AER considered that our actual (adjusted) operating expenditure for 2012-13 was $414.9 million ($2013-14). The AER considered that the substitute base operating expenditure should be $270.8 million ($2013-14), a percentage reduction of 34.7 per cent.

Second, the AER applied its calculation of the rate of change to the substitute base year to derive an operating expenditure forecast for each year of the 2014-19 regulatory period. The AER noted that in dollar terms, the forecast operating expenditure attributed to the AER's calculation of the rate of change was lower than Essential Energy's proposed operating expenditure forecast because the AER's estimate of the rate of change is applied to a lower base level of operating expenditure.

Finally the AER considered that no step changes should be applied to the operating expenditure it derived from the substitute operating expenditure and rate of change calculation. The AER also applied debt raising costs of $19 million (nominal).

AER's assessment under the Rules

The AER stated that in deciding whether or not it was satisfied the service provider's forecast reasonably reflects the operating expenditure criteria it had regard to the operating expenditure factors. This is set out in Table 7-7 of the AER's draft decision[230]. The AER considered that three of the 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 operating expenditure factors, the AER has sought to show how its assessment method relates to one or more operating expenditure factors. In particular, the AER has sought to show how its alternative estimate of operating expenditure meet the factors, including its benchmarking analysis it uses to derive an estimate of the base year. For instance:

- In seven out of the nine factors considered relevant, the AER refers 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 operating expenditure captures the estimate of the inputs that Essential

[230] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p23-25.

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 operating expenditure reflects the operating expenditure criteria. It stated that multilateral total factor productivity analysis considered the overall efficiency of networks in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.

Issues with the AER's assessment method

We have reviewed the AER's draft decision on operating expenditure 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 the operating expenditure criteria to critically assess how our proposals failed to meet them. They have provided no evidence of an assessment other than comparing our forecast to their alternative estimate. In doing so, the AER has not engaged with our specific circumstances and proposed reasons underlying our operating expenditure, in a way that enables a proper assessment under the Rules. Further we contend that that 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 operating expenditure criteria and factors. This is outlined in the sections below.
- Undue weight on benchmarking analysis - The AER has unreasonable weight on benchmarking analysis in making its decision, 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 operating expenditure factors. Further, we demonstrate that it is unreasonable to place significant weight on benchmarking analysis when making its decision due to the errors and limitations inherent in its development and application. This is outlined in the sections below.
- The AER did not consider risks to safety and reliability from substitute operating expenditure - The AER's method for deriving a substitute allowance relies on a benchmarking model that is entirely divorced from the method and cost categories inherent in our forecast operating expenditure. In doing so the AER has considered that its task is to set an overall allowance without undertaking a line by line assessment. 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 had not been considered. This is outlined in the sections below.

… the AER has not engaged with our specific circumstances and proposed reasons underlying our operating expenditure, in a way that enables a proper assessment under the Rules.

… it is unreasonable to place significant weight on benchmarking analysis…due to the errors and limitations inherent in its application.

AER did not consider risks to safety and reliability from substitute operating expenditure…

We consider that if the AER had undertaken its task in accordance with the Rules, then it would have been satisfied that our proposed operating expenditure satisfies the operating expenditure 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 operating expenditure 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.[231]

We consider that such analysis has infiltrated the AER's assessment of operating expenditure, where it has sought to develop a revenue allowance that in its mind achieves the NEO. This is seen in Section 5 of its overview where it 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.

We consider that the AER's task is to assess our forecast operating expenditure under the criteria rather than to derive an efficient level of revenue.

The AER's task is to assess our forecast operating expenditure under the criteria rather than to derive an efficient level of revenue and, in circumstances where it is not satisfied that the forecast operating expenditure 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 regulatory period, the AER seems to have misunderstood this requirement. The distribution determination is built on each of the constituent decisions the AER is required to make pursuant 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 seems 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 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 operating expenditure. 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.[232]

The AER is also of the view that the changes to the NER placed significant new emphasis on benchmarking, however benchmarking was also included in the Rules prior to the 2012 Rule change as an operating expenditure factor available for use by the AER. 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 benchmarking in our expenditure analysis. We will now issue benchmarking reports annually and have regard to those

[231] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p16.
[232] AEMC, *Economic Regulation of Network Service Providers - Final Rule Determination*, November 2012, p vii.

reports. These benchmarking reports provide us with one of a number of inputs for determining the benchmark efficient costs of providing operating expenditure.[233]

As we noted above, the AER has placed exclusive 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 capital expenditure and operating expenditure forecasts but, nevertheless, it did not consider that it should be of greater priority or emphasis than any other operating expenditure factor.

We consider that the AER has misconceived the AEMC's intent on the role of benchmarking.

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.[234]

Not only did the AER use its untested and unreliable benchmarking deterministically, it then incorrectly disregarded the circumstances of Essential Energy, ignoring 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 operating expenditure 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 operating expenditure 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.[235]

AER's alternative estimate

The AER's decision makes clear that it has given primacy to its own alternative estimate for operating expenditure, rather than starting with Essential 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 satisfactorily explain any difference.

Our approach is to compare the service provider's total forecast operating expenditure 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 operating expenditure reasonably reflects the criteria. If we conclude the proposal does not reasonably reflect the operating expenditure criteria, we use our estimate as a substitute forecast.

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233 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating expenditure*, November 2014, p13.

234 AEMC, *Economic Regulation of Network Service Providers - Final Rule Determination,* November 2012, p106.

235 AEMC, *Final Position Paper: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p85.

….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 operating expenditure 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 operating expenditure criteria.[236]

We consider that in applying such an approach the AER has misconstrued its task under the Rules. As we outline below, the AER's task is to review a DNSP's proposal in light of the operating expenditure criteria.

Issues with the way the AER applied its alternative estimate to reject forecasts

The AER is correct in asserting that the AEMC's Rule change did clarify that the Rules do not limit the assessment tools that it can use to assess our proposal. The development of an alternative estimate of operating expenditure is not prohibited by the Rules, and is expressly identified by the AEMC as a tool the AER can use.

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 to satisfy 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. This ignores the fact that it may indeed be that the alternative estimate is demonstrably incorrect, unreasonable or flawed in some way.

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 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.[237]

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 operating expenditure criteria had the AER undertaken a full assessment of our proposal. For example:

We therefore consider it unreasonable for the AER to form a view that its alternative estimate is more accurate than our proposal.

- 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' to be included in its alternative forecast is overly narrow, and effectively precludes operating expenditure that meets the criteria, with regard to the factors. The AER's method simply assumes that costs in the base year reflect the amount required to achieve the operating expenditure objectives, and does not consider whether additional expenditure may be required.

[236] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7*, November 2014, p12.
[237] AEMC, *Economic Regulation of Network Service Providers - Final Rule Determination*, November 2012, p 111.

- The AER's output growth factor cannot account for the changes in relation to the increased maintenance from deferrals in replacement. For example, Essential Energy's forecast increase in operating expenditure as a result of substantial decreases to capital expenditure.

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 probative material we provided in our proposal has not allowed it to make a decision on whether our proposed operating expenditure satisfies the criteria. In fact, the AER's draft decision demonstrates that the AER made its determination based on whether our estimate was close to its alternative estimate, rather than considering whether our proposal satisfied the operating expenditure criteria.

…the AER's narrow review of the probative material…has not allowed it to make a decision on whether our proposed operating expenditure satisfies the criteria.

Attachment 7 of the AER's draft decision stated that it examined our initial proposal and supporting information. However, this is not evident in the AER's reasoning, nor in its consultation with Essential Energy after the initial proposal was lodged. 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 area 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 operating expenditure. For instance, the AER has:

- Not referred to the extensive attachment we provided which shows how our total forecast operating expenditure achieves the operating expenditure objectives and satisfies the operating expenditure criteria.
- Not undertaken an assessment of the activities we perform in achieving the operating expenditure objectives, and the costs incurred 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 for our network and circumstances. For instance, it would have understood that there are safety and reliability consequences from not undertaking maintenance 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 better than the allowance set by the AER as a result of efficient 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 validity of its own 2009-14 distribution determination, and in doing so, rejects the incentive framework that lies at the heat of economic regulation.
- Did not assess change factors unique to our network and circumstances that would impact our cost structure in the 2014-19 regulatory 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 reducing capital expenditure.
- Ignored information we provided on the efficiencies we forecast to derive in the 2014-19 regulatory period, which showed that our forecasting processes had incorporated a level of efficiency that was achievable in our circumstances.
- Not referred to the extensive material and information we provided as attachments and supporting information to our initial proposal which included, asset management plans and business plans that detailed our operating expenditure.

The AER has made statements that our costs included stranded costs for labour that had exited the business. This was a factual error that was relied on to conclude that our proposed operating expenditure contained material inefficiencies. Similarly, the AER made statements around inefficient vegetation management practices that we had already addressed in our proposal by incorporating a significant step change decrease in forecast vegetation management expenditure, that is, we had already removed these inefficiencies.

Reliance on benchmarking as sole criteria

It is clear from the AER's decision that deterministic use of benchmarking has been the primary evidence underlying the AER's rejection and substitution of our proposed operating expenditure. 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 operating expenditure that is report based on the operating expenditure of the average of the top five DNSPs from 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.[238] By publishing the report two months late, the AER has breached the Rules and has not provided us with the 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.

…the AER has breached the Rules and has not provided us with the procedural opportunity to notify the AER of errors prior to the draft determination.

From a substantive point of view, we are concerned that an excessive amount of weight has been given to the benchmarking analysis undertaken by the AER 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 operating expenditure 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 the application of its benchmarking models.

Based on our analysis of the AER's 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: Response to Draft Decision on behalf of NNSW and ActewAGL - Technical response to the application of benchmarking by the AER (Attachment 6.9)
- Frontier Economics: Review of AER's econometric models and their application in the draft determinations for Networks NSW (Attachment 7.1)
- Advisian: Review of AER Benchmarking (Attachment 7.2)
- PWC: Appropriateness of the RIN data for benchmarking (Attachment 6.3)
- Newbery: Expert evidence on economic regulation of networks (Attachment 1.6)
- Pacific Economic Group – Statistical benchmarking for NSW Distributors (Attachment 7.3).

[238] Clause 6.27(d) of the NER

Role of benchmarking in the context of the operating expenditure 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 10 explicit factors that the AER must have regard to when assessing whether forecast operating expenditure meets the operating expenditure criteria. We consider that the AER has almost exclusively relied 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 development.

The AER's assessment techniques are 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 only referred to two other techniques which are a labour cost efficiency review (which in large parts is also based on benchmarking analysis) and a review of our proposal, which we demonstrated above was superficial.

The AER purports to have regard to other operating expenditure factors in the table on page 23 to 25 of Attachment 7 of its draft decision. However the AER's statements against each factor (with the exception of customer engagement) refer to its benchmarking analysis as the 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 preceding regulatory periods were:

> *Our forecasting approach uses the service provider's actual operating expenditure as the starting point. We have compared several years of Essential Energy's actual past operating expenditure 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 operating expenditure in the forthcoming period.*[239]

We consider that such an approach unreasonably refers each factor back to the benchmarking factor, giving a disproportionate weight to its analysis, and nit enabling a meaningful contemplation of each factor. We also note that the AER sought to add two additional operating expenditure 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 modelling or techniques not in the Annual Benchmarking report.

From this type of analysis it is clear that the AER has 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 operating expenditure factors that are required to be considered in the AER's assessment of forecast operating expenditure in Essential Energy's proposal or in developing its substitute forecast operating expenditure , including actual and past expenditure, and the incentive mechanisms that apply. Had the AER considered these factors it may have concluded that our operating expenditure in the 2012-13 base year was better than the determination the AER had set in the 2009-14 determination.

> *…our operating expenditure in the 2012-13 base year was 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 operating expenditure for Essential Energy for the 2009-14 regulatory period and the incentive scheme that it applied to Essential 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 determination and retrospectively re-determine its view of an efficient level of operating expenditure, when it has adopted a base year roll forward approach to determining the efficient level of operating expenditure. Adopting a base year approach to determining operating expenditure,

[239] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p 23.

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 operating expenditure.

The 2009-14 determination made by the AER was the basis upon which Essential Energy set its business objectives, operations and management decisions for this period. We fail to comprehend how an actual operating expenditure outturn that is below the efficient operating expenditure allowance determined under a valid AER determination can subsequently be found to be inefficient, as the AER has found in its draft decision for the 2014-19 regulatory period.

In any case, the Rules require the AER to have regard to the individual circumstances of the business by requiring the AER to accept the proposed forecast of operating expenditure that reasonably reflects the operating expenditure criteria which include the costs that a prudent operator would require to achieve the operating expenditure objectives and a 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 analysis to identify areas where further investigation might be warranted.

The AER did not, as in previous determinations undertake a detailed assessment of components of operating expenditure or commission an engineering review of maintenance programs. Instead, the AER relied exclusively on an untested benchmarking regime to mechanistically derive very large adjustments to the base year operating expenditure for NSW and ACT DNSPs.

The AER only undertook a review of one aspect of our forecast operating expenditure (labour practices also relying to a large degree on benchmarking) to determine the reasons underlying observed differences in costs that resulted from its own 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. The limitations of the AER/EI benchmarking approach, the data used, the model specifications selected, the lack of consideration of alternative models and their implications, and the mechanistic application of the results is discussed in detail in the following sections.

Conceptual limitations with benchmarking

The AER developed its benchmarking approach as a central theme of the Expenditure Forecast Assessment Guideline and acknowledged throughout the development of the Guideline 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. We consider that it was unreasonable and unwise for the AER to give substantial weight to its benchmarking analysis in light of conceptual limitations of benchmarking itself, and even more concerning in the Australian context given the limited data available (i.e. small sample of distributors) and its implications for model specification and econometric techniques.

We raised concerns with the fitness for purpose of benchmarking tools that the AER planned to use as part of our determination in our initial proposal. 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. Based on our analysis and that of our consultants, our concerns about the AER’s benchmarking approach have been well founded.

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 heterogeneous nature of DNSPs and their operating conditions. As we predicted during the consultation on the Expenditure Forecast Assessment Guideline and again in our initial proposals, it is impossible to normalise for the array of differences between DNSPs in Australia and each business’ 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 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 as to how the AER should 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 clause 6.27 and clauses 6.5.6 (in respect of operating expenditure) and 6.5.7 (in respect of capital expenditure). Clause 6.27 of the NER 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 operating expenditure reasonably reflects the operating expenditure criteria. Clause 6.5.6(e)(4) provides that the AER must have regard to:

1. The most recent annual benchmarking report; and
2. The benchmark operating expenditure that would be incurred by an efficient DNSP.

In deciding whether or not it is satisfied that a forecast operating expenditure amount reasonably reflects the operating expenditure 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 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 operating expenditure 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 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 operating expenditure for the 2014-19 regulatory period.

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.[240]

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,*

[240] Victorian Department of Primary Industries, *Proposed Rule Change to the Australian Energy Market Commission to permit the use of the 'TFP Approach'*, May 2008.

> *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.*[241]

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 charges and revenues. The AEMC engaged EI to provide advice 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"*.[242] EI went on to say that there was a strong case for developing a well specified and robust national TFP database for the electricity distribution industry and that such a database *"would allow potential application of an alternative method of regulation in the future"*.[243] Further, EI stated that it 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*".[244]

In their 9 June 2009 report, EI emphasised 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.[245] 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"*.[246] 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 for the first time to date forms an appropriate basis for the determination of operating expenditure (or capital expenditure) 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.*[247]

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.[248] The AEMC found that:

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241 Letter from S Edwell (Chairman, AER) to J Tamblyn (AEMC), 20 August 2008, p2

242 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.

243 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.

244 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.

245 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.

246 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.

247 Letter from S Edwell (AER) to J Tamblyn (AEMC), 30 October 2009, p 1.

248 AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.

> *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.*[249]

The AEMC concluded that the *"initial focus should therefore be on establishing a better, more consistent data set".*[250] 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.[251] 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 be considered.[252]

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.[253]

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 Essential Energy's regulatory allowance, the considerations that apply to the use of TFP to set such allowances, apply equally to the use of MTFP 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"*[254] 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 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 NEO. This second step has not occurred. As such, the AER cannot, and should not, rely on the benchmarking it has undertaken to fundamentally determine Essential Energy's forecast operating expenditure 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…*[255]

[249] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii
[250] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.
[251] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report,* 30 June 2011, p ii.
[252] AEMC, *Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report*, 30 June 2011, p ii.
[253] AEMC, Review into the use of Total Factor Productivity for the determination of Prices and Revenues: Final Report, 30 June 2011, p ii.
[254] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p13.
[255] Productivity Commission, *Electricity Network Regulatory Frameworks, Report No. 62*, 9 April 2013, p33.

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.*[256]

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.[257]
- 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.[258]
- The AER should develop and maintain appropriate benchmarking databases and in-house expertise for the technical analysis required to undertake sophisticated benchmarking.[259]
- 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.[260]
- The AER should submit its major benchmark analyses of electricity networks for independent expert peer review to establish their ongoing relevance, scientific validity, adoption of best-practice, and to guage the degree of uncertainty in the results.[261]

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 and that, over time, repeated use of benchmarking models will improve the reliability of the models' estimation of nework efficiencies and increase the potential for them to have greater weight in regulatory decisions.[262]

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.

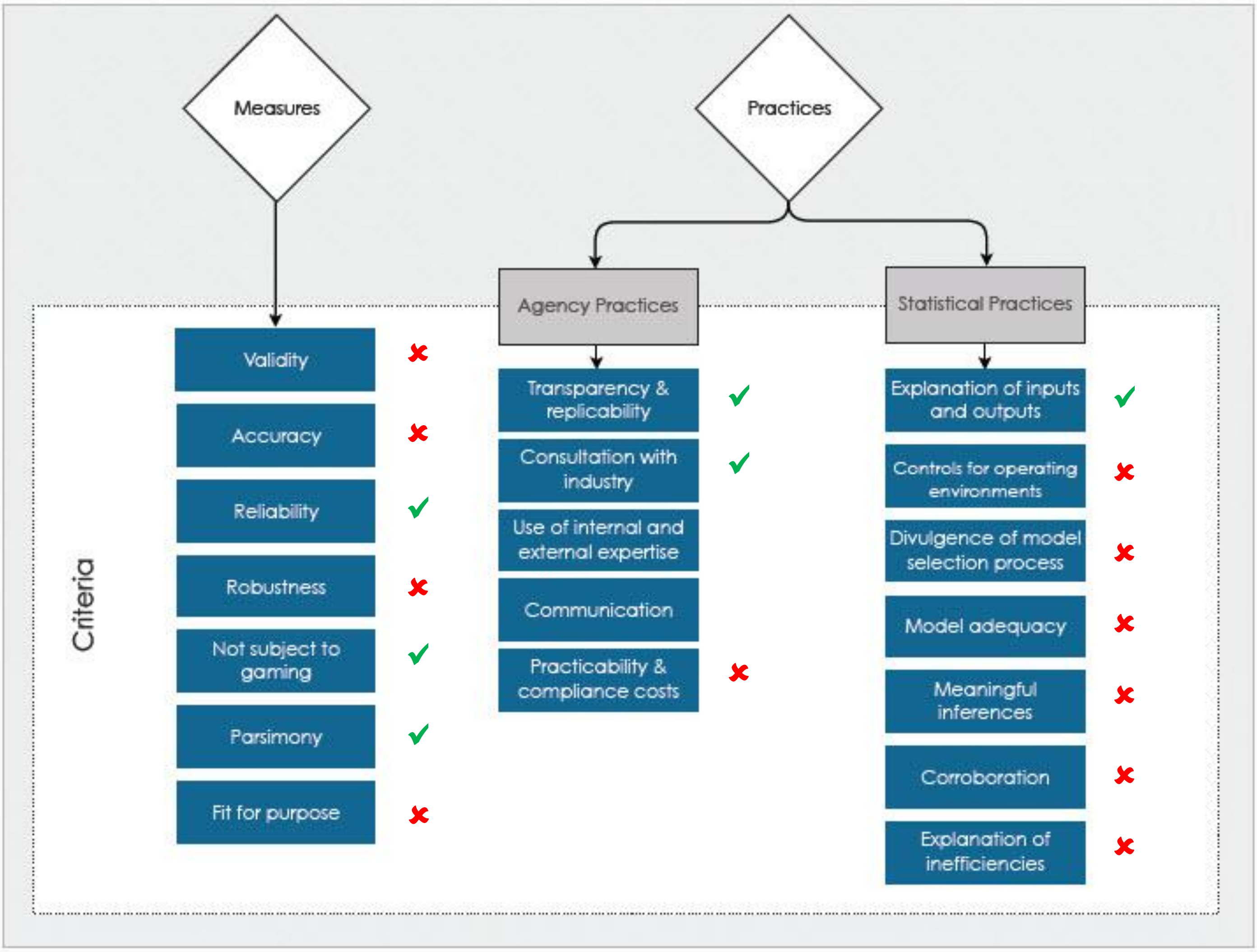
To identify whether the AER's approach to benchmarking is consistent with best practice and therefore fit for purpose in the context of a regulatory determination, our consultants, Huegin, have assessed the AER's approach against the Productivity Commission's best practice measures of benchmarking as outlined in its 2013 report.[263]

Huegin Consulting found that the AER overall has failed to apply a benchmarking approach that is consistent with best practice. While 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

[256] Productivity Commission, *Electricity Network Regulatory Frameworks*, Report No. 62, 9 April 2013, p3.
[257] Productivity Commission, *Electricity Network Regulatory Frameworks, Report No. 62,* 9 April 2013, p52 (recommendation 8.1).
[258] Productivity Commission*, Electricity Network Regulatory Frameworks, Report No. 62,* 9 April 2013, p54 (recommendation 8.5).
[259] Productivity Commission*, Electricity Network Regulatory Frameworks, Report No. 62,* 9 April 2013, p54 (recommendation 8.6).
[260] Productivity Commission*, Electricity Network Regulatory Frameworks, Report No. 62,* 9 April 2013, p55 (recommendation 8.9).
[261] Productivity Commission*, Electricity Network Regulatory Frameworks, Report No. 62*, 9 April 2013, p55 (recommendation 8.10).
[262] Productivity Commission*, Electricity Network Regulatory Frameworks, Report No. 62,* 9 April 2013, p334.
[263] Productivity Commission*, Electricity Network Regulatory Frameworks, Report No. 62,* 9 April 2013.

Practices. This is demonstrated in Figure 7-2. 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.

Exhibit 3.1: Benchmarking Assessment Framework. *Benchmarking measures and practices can be evaluated against criteria designed to inform the explanatory power of the measure(s), efficacy of the models used to generate them and the appropriateness of the process to deploy and utilise them.*



Adapted from: Figure 4.7 of Productivity Commission 2013, Electricity Network Regulatory Frameworks, Report No. 62, Canberra.

Figure 7-2: Huegin Benchmarking: adapted assessment framework[264]

264 Huegin, *Response to Draft Determination on behalf of NNSW and ActewAGL: Technical response to the application of benchmarking by the AER,* 14 January 2014, p19-27.

A full explanation of the Productivity Commission criteria and Huegin's assessment of the AER's benchmarking practice against these criteria is shown in the Huegin report which can be found at Attachment 6.9.

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 data preparation and testing of results. This has led the AER to reject and substitute our proposed operating expenditure in a manner that does not satisfy the operating expenditure criteria in the Rules, and subsequently does not meet the NEO and the Revenue and Pricing Principles in the NEL.

Furthermore, it was imprudent of the AER to develop a benchmarking model for the specific purpose of deriving a base year operating expenditure 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 operating expenditure based on error, poor judgment and reckless 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 EI, 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 AER has made a decision to reject and substitute our proposed operating expenditure based on error, poor judgment and reckless disregard of the consequences of its decision to the safety and maintenance of our network.

The following sections outline the errors that have been identified and are supported by our experts Frontier Economics, PEG, Huegin Consulting, Professor 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 Expenditure Forecast Assessment Guideline 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 in the context of the draft Determinations for NSW and ACT distributors. This would have enabled proper peer review.

Furthermore, we contend the AER departed from its final Expenditure Forecast Assessment Guideline by making substantial changes to the way it undertook its 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 peer review at all.

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 the ACT. Not only are the operating expenditure adjustments greater than any imposed by a regulator internationally which would naturally highlight a need for a 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 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.

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 EI, PEG, Huegin and Frontier Economics all demonstrate the variation in results that can be achieved through the use of different modelling techniques and model specifications. The AER/EIwas 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.[265]

The AER and its consultant EI 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.[266]

False Frontier

The AER and EI have 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 regulatory 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 operating expenditure data sets the frontier at a point in 2009 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[267]. 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.[268]

… by using an average operating cost that equates to costs in 2009 in its models, the AER has established a false frontier – one that even those businesses on the frontier in 2009 can no longer meet.

The use of 2009 data for Victorian DNSPs fails to capture the significan 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

[265] 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*, 2015, p80-84.

[266] 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*, 2015.

[267] Huegin, *Response to Draft Decision on behalf of NNSW and ActewAGL – Technical response to the application of benchmarking by the AER*, 2015, p46.

[268] SA Power Networks, *Regulatory Proposal 2015-2020,* Section 9.2.1, p87.

to 2013. In addition, backlogs in both maintenance tasks and safety programs in maintenance tasks have been highlighted in their recent report.[269]

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, WHS and asset management obligations.

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 nine per cent which has the effect of reducing any operating expenditure adjustments made by the AER by nine per cent 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.[270]

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 consultants PEG.

In either case, the selection of variables is limited to data gathered. Despite the significant collection of data via the RIN, EI 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 in its expert report (Attachment 7.3) 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 / New Zealand data set.[271] In this case, the use of international data from Canada / New Zealand had a profound negative effect on the explanatory power of the EI model.

The use of international data therefore, has 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 set available in Australia 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

269 Energy Safe Victoria, *Safety Performance on Victorian Electricity Networks*, 2013.

270 Huegin, *Response to Draft Decision on behalf of NNSW and ActewAGL – Technical response to the application of benchmarking by the AER*, 2015, p38.

271 Pacific Economics Group Research, *Statistical Benchmarking for NSW Distributors*, 2015, p52.

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 note with concern the impact of excluding meaningful variables. Huegin assess the drivers of network costs and test them against the variables selected by the AER/EI models, as shown in Figure 7-3. Of the three variables included in the model, line length was assessed as having the strongest relationship with cost, with the number of customers having a moderate impact on cost. Peak demand was assessed as having very little relationship to cost at all.

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

Figure 7-3: Huegin Consulting's assessment of cost categories, cost drivers against AER benchmarking variables[272]

Furthermore, Advisian have 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 signficantly to differences in cost drivers for the NSW DNSPs including[273]:

[272] Huegin, *Response to Draft Decision on behalf of NNSW and ActewAGL – Technical response to the application of benchmarking by the AER*, 2015, p35.
[273] Advisian, *Review of AER Benchmarking*, January 2015.

- 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 operating expenditure have not been taken into account:

- Asset age
- Climate and environment
- Customer demographics
- Network design
- Network voltages
- Network accessibility
- Network utilisation
- Reliability standards
- Scale
- Policy and regulation; and
- Physical environment in which the business operates.

These factors will all explain part of the operating expenditure 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 factors that are material to determining the efficient operating expenditure requirements for the business which they argue have not been appropriately taken into account in the model for the purpose of determining efficient operating expenditure:

- 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 recognition of the impact of spatial density (customers per km^2) as distinct from linear density (customers per km) on the nature and configuration of electricity distribution networks, and consequently on the efficient operating expenditure requirements for a distribution network.[274]

The AER reviewed the Weighted Average Remaining Life (WARL) of the DNSPs and stated that it did not need to include an operating environment factor for differences in assets age, and made the statement that:

[274] Advisian, *Review of AER benchmarking*, January 2015, p52-53.

> *..Essential Energy may have a slight cost advantage relative to the comparison firms on maintenance opex because their networks are, on average, younger so their assets should require less maintenance.*[275]

Advisian do not concur with the AER's findings that *"The age profiles of the NSW service providers and the comparison service providers are similar, and therefore should not lead to material differences in their Opex".* Advisian's analysis shows that:

> *…the AER's assessment of the relative 'age' of the NSW networks is fundamentally misleading when compared to reported asset age profiles contained in the RIN information provided by the businesses.*[276]

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[277] 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. 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:

> *…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 an insufficient method of controlling for differences.*[278]

Professor Newbury 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.*[279]

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 Newbury 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* [sic] *specifications*."[280]

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275 AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p128-129.

276 Advisian, *Review of AER Benchmarking*, January 2015, p77.

277 http://www.economics.ubc.ca/files/2013/06/pdf_paper_erwin-diewert-electricity-distribution.pdf

278 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*, 2015, p47.

279 David Newbery, *Expert Report*, January 2015, p11.

280 David Newbery, *Expert Report*, January 2015, p12.

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 capital expenditure/operating expenditure trade offs, cost allocation and capitalisation policies.

In respect of international data, EI 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 suggest 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 operating expenditure 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. [281]

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[282]. The differences in definitions are clear. For example, the circuit kilometers definition in New Zealand specifically state that *“when a pole or tower carries multiple circuilts, the lenth 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”*.

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 fact that these differences have come to light after the AER has published its draft determination …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

[281] Pacific Economics Group Research, *Statistical Benchmarking for NSW Distributors*, 2015, p54.
[282] 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*, 2015, p45.

in size to Australian businesses when comparing circuit length. Advisian put this compariosn another way by noting that Ontario is approximately 60 per cent of the area of Queensland with the largest business, Hydro one serving approximately 75 per cent of the province. This leaves approximately 70 DNSPs serving a relatively compact area that is compareable 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."*[283]

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 : 5125. This ratio is significantly greater than the linear density ratio of 4.3 customers / km (Ergon Energy) to 75 customers / km (Citipower) - a ratio of only 1 : 17.[284]

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 operating expenditure and cost drivers.

These differences in cost structures and drivers between the Australian and Ontario based businesses are significant 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').

> *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 elasticitiy on the four main drivers of costs (customer numbers, circuit length, ratcheted 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.*[285]

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.

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.

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

[283] Advisian, *Review of AER's Benchmarking*, January 2015, p15

[284] Advisian, *Review of AER's Benchmarking*, January 2015, p29

[285] 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*, 2015, p24.

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 dcoumentation) 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 operating expenditure (as opposed to capital expenditure)
- There are material differences in accounting methodologies and application of accounting standards which have the potential to impact the size of operating expenditure used in EI's calculations.

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 businesses.[286] With this in mind, the AER's use of vegetation management costs to validate the benchmarking outcomes across the NSW DNSPs would appear misguided.

…the AER is comparing higher cost businesses with lower cost businesses and attributing differences to management performance…

The AER has failed to apply simple sense checks to the results.

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*."[287] They go on to identify a number of analytical inconsistencies in the AER's 'detailed review' which include:

i. The failure to fully consider the vegetation management information provided by the DNSPs in respons to the AER's RIN requirements;

ii. The failure to account for differences in DNSP responsibility for vegetation management works between jurisdictions;

iii. Analytical inconsistencies and errors in the calculation of overhead route kilometres;

iv. The ultimate reliance on a single year result for one business (Essential Energy) to infer that all NSW DNSPs are inefficient;

v. Reliance on an erroneous assessment of the reliability impact of vegetation outages to infer that the impact of vegetation outages is increasing.[288]

Frontier also point to a lack of specification within the RIN compared to that which is common in other jurisdictions, 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.[289] All other adjustments have been made outside the model.

[286] Advisian, *Review of AER Benchmarking*, January 2015, p39.
[287] Advisian, *Review of AER Benchmarking*, January 2015, p4.
[288] Advisian, *Review of AER benchmarking*, January 2015, p4.

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.*[290]

Both Huegin and Frontier agree that the post-modelling adjustments are unlikely to be sufficient to account for the different operating conditions.[291] [292]

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 operating expenditure reductions which are unprecedented internationally [293] and the manner in which it has been applied retrospectively. Frontier argues 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.[294] 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 Ontarion 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.*[295]

The AER's decision to apply base year operating expenditure adjustments recommended by the EI model from the first year of the period is not consistent with regulatory practice in other jurisdictions. Newbery, Huegin, PEG and Frontier all point to the manner in which Ofgem has acknowledged differences in modelled outcomes, and 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 per cent 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.[296] 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.

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[289] Advisian consider that the use of this simple measure is not sufficient and it does not account for voltage differences within this measure which in their view, is material. Advisian*, Review of AER benchmarking*, January 2015, p28-29.

[290] Professor David Newbery, *Expert Report*, January 2015*,* p12.

[291] 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*, 2015, p98.

[292] Huegin, *Response to Draft Decision on behalf of NNSW and ActewAGL – Technical response to the application of benchmarking by the AER*, 2015, p44.

[293] 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.

294 It is interesting to note that the OEB was assisted by PEG in this analysis.

295 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*, 2015, 62.

296 Professor David Newbery, *Expert Report*, January 2015, p24.

In Norway, the regulator also applies a direct weighting to the distributors costs of 40 per cent with the remaining 60 per cent weighting being applied to benchmarking results.[297] No such balancing of the benchmarking outcomes with distributors costs has been made by the AER.

The Ontario Energy Board (OEB) has also applied benchmarking in the context of price reviews but have not translated measured relative inefficiency between networks 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 tranch over time. In its last review, the largest adjustment factors applied as a stretch factor was 0.6 per cent 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 draft decision is to cut operating expenditure by up to 40 per cent 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 per cent stretch factor (applied to the worst Ontarian performer) equates to a five year revenue cut for Ausgrid of $73m[298] compared to the proposed operating expenditure cut for Ausgrid of $1,130m (effectively a revenue cut) proposed by the AER. In dollar terms the AER's reduction to operating expenditure 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 per cent) 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 negative one, zero and one per cent.[299] Using the example of Ausgrid once again, an X-factor of one per cent applied to Ausgrid's 2014 proposal would equate to a reduction of proposed revenue of about $122 million over five years. In contrast, the AER's proposed cuts to operating expenditure of $1,130 million 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*".

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 per cent of the costs that would be provided to CitiPower on a normalised basis. For Ausgrid, the rate is 60 per cent of the equivalent Citipower costs.[300] Attachment 7.4 provides further analysis on the reasonableness of Essential Energy's operating expenditure forecast and the nonsensical implications of the AER's draft decision.

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.

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

297 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*, 2015, p105.
298 (proposed SCS revenue $12,189M x 0.6%).
299 Professor David Newbery, *Expert Report*, January 2015 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.
300 Advisian, *Review of AER benchmarking,* January 2015, p42.

credible representation of base year expenditure and should not be used.

Based on the above evidence we consider that the benchmarking analysis contains errors, and accordingly we have not revised our proposal for the AER's analysis.

No reasonableness check of substitute operating expenditure allowance

The AER's substitute allowance for operating expenditure was derived from its benchmarking analysis. The AER used the results of a model specification developed by its consultant to identify the average operating expenditure of the top five 'frontier firms' in the analysis. The AER then applied a ten per cent increase to this level of operating expenditure to recognise factors that may increase the costs of providing services in our network. The AER then applied an operating expenditure growth factor based on its own calculation, and no other increase in costs that we proposed.

The AER's approach has been to effectively develop an operating expenditure substitute in isolation from our proposed operating expenditure. In deriving the substitute the AER has not considered our activities and costs in undertaking those activities but rather, developed a quantum of operating expenditure based on a single benchmark model. As noted in the sections 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 obligation 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 operating expenditure objectives. Rather than undertake a reasonableness check of its benchmarking analysis, the AER states:

> *… we determine a service provider's operating expenditure 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 operating expenditure 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 the operating expenditure our decision allows for.* [301]

It is not sufficient to state that a DNSP is free to choose how to manage its allowance, without providing the DNSP with the allowance necessary to meet the objectives.

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 (Attachment 1.2) and Jacobs Group Australia in relation to prudency (Attachment 1.4) and reliability (Attachment 1.5).

R2A noted..

> *If Essential Energy were to operate within the constraints of the AER's 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 quadrupling of fatalities from networks hazards is most likely to occur. In addition, the likelihood of the Essential Energy network starting a catastrophic bushfire (meaning 100 fatalities and 1,000 houses lost) triples as a result of increased equipment failures due to longer inspection cycles.* [302]

and

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[301] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p12.

[302] R2A, *Asset / system failure safety risk assessment,* January 2015, p4.

The AER draft determination as it stands is, in effect, directing Essential Energy to disregard Essential Energy's own determination of what Essential Energy believes is necessary to demonstrate SFAIRP (so far as reasonably practicable) under the provisions of the Work Health and Safety Act 2011.[303]

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.[304]

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. [305]

We consider that a reasoned decision maker would consider the risks that would arise from its substitute operating expenditure allowance. One means of doing this would be to assess the activities that the DNSP has identified as being required to achieve the operating expenditure 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 operating expenditure 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.

…a reasoned decision maker would consider the risks that would arise from its substitute operating expenditure allowance.

Addressing substantive issues raised in the AER's decision

In undertaking its assessment method, the AER reviewed elements of our proposal including labour practices, vegetation management practices, and redundancy payments. The AER also reviewed our proposed output growth, real cost escalation and productivity.

Both the AER and 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 Essential Energy's workforce.

The success of the NSW Network Reform Program, commenced in July 2012, is clear evidence of the potential to progressively improve both the capital and operating efficiencies of Essential Energy. The continuation of that program is embedded in this revised proposal with committed labour productivity improvements of 22.6 per cent by the end of the regulatory period.

The success of the NSW Network Reform Program, commenced in July 2012, is clear evidence of the potential to progressively improve both the capital and operating efficiencies of Essential Energy. The continuation of that program is embedded in this revised proposal…

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.

[303] R2A, *Asset / system failure safety risk assessment,* January 2015, p5.
[304] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p2.
[305] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p53.

> *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.*[306]

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.

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.

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.

Labour cost efficiencies

The AER considered that our labour structure and costs are inefficient. The AER's opinion has been informed by Deloitte's review of labour and workforce management practices of the NSW service providers.

Deloitte found in respect of the labour costs incurred in delivering the capital expenditure program (labour-related capital expenditure), 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 capital expenditure program, and that all service providers' labour-related capital expenditure 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 operating expenditure adjustments. It was satisfied that labour and workforce management contributes to a material source of inefficiency in operating expenditure in the 2012-13 base year (as supported in benchmarking analysis) for each of the NSW service providers.

Essential Energy has considered the findings of the AER and considered whether revisions are necessary to incorporate the substance of the findings. Confidential Attachment 7.5, Attachment 7.6, Confidential Attachment 7.7 and Confidential Attachment 7.8 set out how we have undertaken the task of reviewing the AER's findings. We consider that based on this review that there is no information or analysis that has caused us to make revisions in response to the AER's findings. This is for the following reasons:

306 The Australian, *Privatise to reduce power of unions', says Vince Graham,* 20 August 2014.

- 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 regulatory period, and incorporated the impact of efficiency programs on our operating expenditure in the 2014-19 regulatory period.
- The Deloitte report has not provided any evidence or analysis that demonstrates its' claims that our unit labour costs are high. There is no labour cost comparison across distributers in the Deloitte report.

We have revised our proposal to incorporate the latest estimates on our labour costs for operating expenditure. This is based on updated information on efficiency programs we are implementing, which show an adjusted rate of labour productivity than that forecast at the time of our initial proposal.

Efficiency programs implemented at Essential Energy

The AER and Deloitte have not sufficiently recognised the efficiency initiatives that we have put in place at Essential Energy over the 2009-14 regulatory period, and the efficiencies we have factored into our forecasts in the 2014-19 regulatory period.

The evidence we submitted to the AER has made it very clear that Essential Energy responded to the efficiency incentives put in place by the AER in the 2009-14 regulatory period. Our operating expenditure was below the efficient and prudent allowance determined by the AER in its 2009-14 determination. Essential Energy provided substantive evidence to demonstrate the efficiency activities we undertook in the 2009-14 regulatory period that resulted in us delivering a lower operating expenditure. These include:

> *The evidence we submitted to the AER has made it very clear that Essential Energy responded to the efficiency incentives put in place by the AER in the 2009-14 regulatory period.*

- Workforce planning - Essential Energy has made significant progress in implementing more efficient delivery models. Using a staged transition, we are steadily moving from a predominantly internal labour force to a blended model of internal and external resources. The competitive tension achieved through such a model has led to delivery efficiencies.
- Market testing - We have also market tested a number of areas, including our most significant operating expenditure activity of vegetation management that resulted in work going to external providers for the benefit of customers.
- Robust wage negotiations with our staff - In an environment of significant demand for labour, we have managed strong and robust negotiations with our staff. Wage restraint has been the key to keeping labour costs lower over the period, together with better management of inefficient allowances. Refer to Attachment 7.5 for more information.
- 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 flexible delivery models, and by exiting staff via natural attrition and staff freezes.
- Reduced supply - Essential Energy has had significant reductions through natural attrition and reduction in agency staff and external appointments. Combined with reduced apprentice intake numbers, the internal labour supply has been reduced. In the two and a half years since the formation of NNSW, Essential Energy has reduced its labour size by over 700 employees through a combination of supply and exit plan initiatives.

> *The Network Reform Program has resulted in considerable change and will deliver a more efficient, lower cost electricity distribution service to customers that is financially sustainable, eliminates unnecessary waste, and maintains the reliability and sustainability of the network in a way that is safe for employees and the public.*

Our forecast operating expenditure for the 2014-19 regulatory period also incorporated achievable efficiencies. These were based on granular assessments of our functions and activities. The AER has ignored this information in forming its conclusions.

Our efficiency programs are an extension of the progress we have made in the 2009-14 regulatory period, and incorporate the synergies that the NNSW model has unlocked across the three NSW DNSPs.

The Network Reform Program has resulted in considerable change and will deliver a more efficient, lower cost electricity distribution service to customers that is financially sustainable, eliminates unnecessary waste, and maintains the reliability and sustainability of the network in a way that is safe for employees and the public. Savings to operating expenditure of $141 million ($2013-14) for the 2014-19 regulatory period are expected from the implementation of the Network Reform Program and these savings have been incorporated into the forecast operating expenditure requirement. Table 7-5 shows the expected operating expenditure savings from the four initiative streams of the Program.

Table 7-5: Operating expenditure savings from network reform program ($2013-14, millions)

	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
New operating model	16	17	18	18	18	86
Strategy and policy	2	2	3	3	3	13
Procurement and logistic	6	10	10	10	5	42
Total cost reduction	**24**	**29**	**31**	**30**	**26**	**141**

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 is consistent with our operating licence conditions legislated by the NSW parliament, and the Fair Work Act, the Federal legislation that governs the processes surrounding the Industrial Relations framework under which we must operate our workforce.

> **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.

> **Affordably** - in a way that minimises the cost of change for the electricity customers 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.

Essential 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 $494 million), 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 7.9 sets out the process Essential 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.

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 operating expenditure that will reasonably reflect the operating expenditure criteria for the 2014-19 regulatory period.[307] 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 operating expenditure 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 operating expenditure cuts.[308]

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."*[309]

Instead of attempting to assess remuneration in a way that reflects the combined components of labour costs, Deloitte instead analysed a few selected provisions from the EBAs for a relatively small number of Essential employees. Deloitte has focused its analysis in the report on superannuation, long service leave and overtime. [310]

Essential Energy accepts there are some aspects of the current EBA such as Superannuation, Long Service Leave and certain allowances that do need to be addressed as part of the upcoming negotiations for the 2015 EBA to further improve labour efficiencies. These improvements, along with others, will form part of the negotiations for the 2015 EBA under the good faith bargaining requirements of the FWA. However, 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 therefore trade-offs between different elements of remuneration and workplace practices would be expected. This fact is recognised by the AER in its draft determination[311] 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*

[307] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p87.

[308] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p90.

[309] Deloitte, *NSW Distribution Network Service Providers Labour Analysis*, 17 November 2014, p31.

[310] 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.

[311] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Overview*, November 2014, p151.

negotiations between SP AusNet, its employees and representative unions and we are not privy to these negotiations.[312]

Analysis of broader elements of remuneration 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, shown in Figure 7-4, our labour costs are comparable to other DNSPs[313] in Australia. 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.

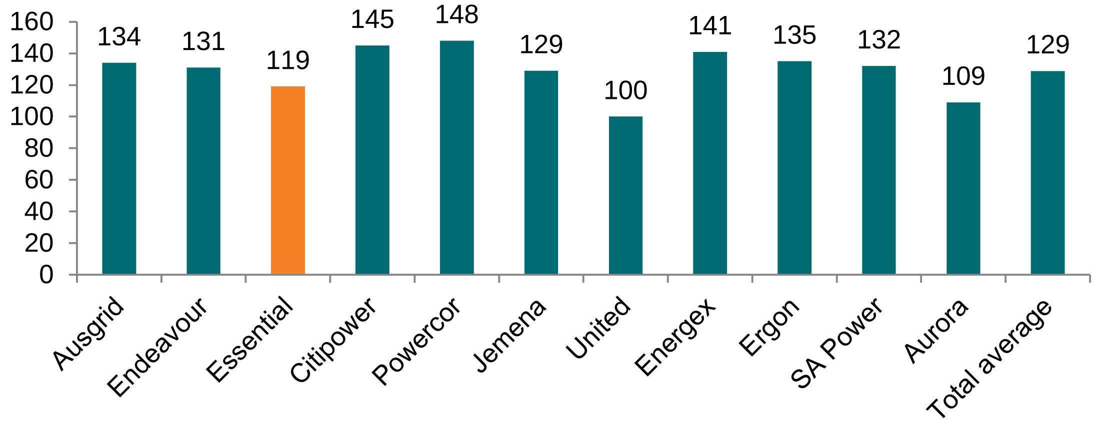

Figure 7-4: Average labour cost per ASL[314]

Essential Energy undertook its own analysis of labour costs (Confidential Attachment 7.5) and NNSW engaged CEG to undertake analysis of labour costs compared to other DNSPs (Attachment 7.7). Essential Energy's analysis and the CEG report[315] attached to this revised proposal both found that our labour costs were comparable to our peers.

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312 AER, *Final Decision SP AusNet Transmission determination 2014-15 to 2016-17*, p82.

313 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.

314 We note that Ausgrid and AusNet Services have made information in template 2.11 confidential.

315 CEG, *Labour unit cost – review of Deloitte report*, 2015 provided as Attachment 7.7

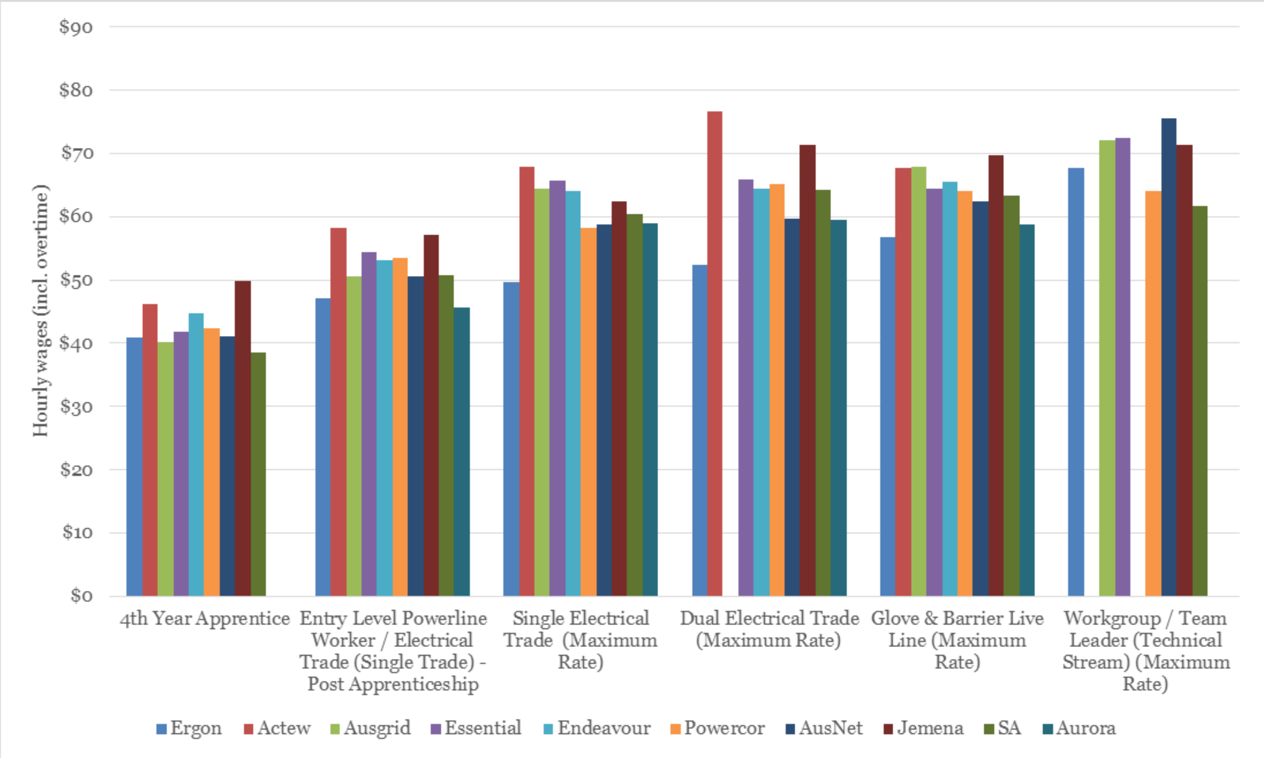

Figure 7-5: Comparison of unit labour costs for representative employees[316]

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 favorable than those contained in the DNSPs 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.

Deloitte also found that we have greater restrictions on workplace flexibility. They note they have not attempted to undertake a clause by clause comparison of EBA arrangements. NNSW engaged K&L Gates[317] to undertake a comparison of the EBAs for NSW DNSPs and DNSPs in other jurisdictions in relation to provisions that restrict workplace flexibility. K&L Gates, who are experienced industrial relations lawyers, found that the assertion that labour practices within our EBA are more restrictive than similar labour practices in other DNSPs in other jurisdiction cannot be sustained. K& L Gates comparison of the EBA's is provided at Attachment 7.8. Essential Energy's assessment on workplace flexibility reached a similar conclusion as detailed in Attachment 7.5.

[316] CEG, *Labour unit cost – review of Deloitte report*, 2015 provided as Attachment 7.7. See Figure 1, p2.
[318] *2009 Victorian Bushfires Royal Commission Final Report Summary*, July 2010, p12.

Again Deloitte seems to have analysed on a small number of provisions from within the EBAs to support its conclusion. As part of their analysis on all relevant provisions, K&L Gates analysed these provisions and their findings do not support the conclusions made by Deloitte. .

Essential Energy accepts there are aspects of our current EBA 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 the Deloitte Access Economics' 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 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.

Unreasonable approach to reviewing our proposed vegetation management costs

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 had not been paying sufficient regard to the safety implications, with these issues arising from insufficient regulatory allowances. The Royal Commission into the 2009 Black Saturday bushfires noted that 173 people had died in the bushfires. The Commission stated:

> *The importance of prudent vegetation management has been put into the spotlight as a result of catastrophic damage of bushfires across the nation.*

> *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.*[318]

It is in this context that we consider the AER has taken a very unreasonable approach to reviewing our proposed vegetation management costs. The AER's assessment method involved a superficial review of benchmarking data, and an incorrect approach to reviewing our proposed decrease in costs relative to the base year. Of particular concern is the quantum of reduction in Essential Energy's vegetation control program implied by the AER's 38 per cent aggregate reduction in operating expenditure. The Commissioners of NSW Fire and Rescue and the 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. These letters are provided in Appendix B of Attachment 3.3.

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 (operating expenditure objective 1). We have general obligations relating to the safety and reliability of the network, and particular obligations relating to bushfire mitigation.

[318] *2009 Victorian Bushfires Royal Commission Final Report Summary*, July 2010, p12.

- We apply a prudent standard to determine the activity required to achieve our regulatory obligations. We use a national standard that is widely recognised as 'best practice', which 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 costs were based on external 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 required to achieve. We consider this provides a level of satisfaction as to the efficiency of our costs.

Benchmarking

The AER's approach to assessing our operating expenditures relied heavily on top down benchmarking analysis. As discussed in previous sections, Essential Energy firmly believes the benchmarking analysis carried out by the AER is heavily biased and flawed, and relies on notions of efficiency by state borders, rather than examining the underlying reasons for any identified differences. Our operating expenditure reflects programs that are common to all DNSPs and conducted in line with standard industry practice.

The base year operating expenditure determined by the AER in its draft decision is inadequate for the Essential Energy network given the scale, operating environment and diversity of assets. The AER draft decision has relied heavily on benchmarking that placed an inordinate weighting on customer numbers and ratcheted demand and was materially biased in favour of high density, low feeder length utilities. The AER did not adequately consider the limitations of the benchmarking methodology to ensure homogeneity across the benchmarked utilities with regards to efficiency comparisons.

Figure 7-6 demonstrates that Essential Energy services a similar number of customers as its comparable peers but over a substantially longer network. The primary driver of operating expenditure for a rural distributor is total assets, their condition, and their operating environment. Customer numbers and maximum demand have a much lesser effect.

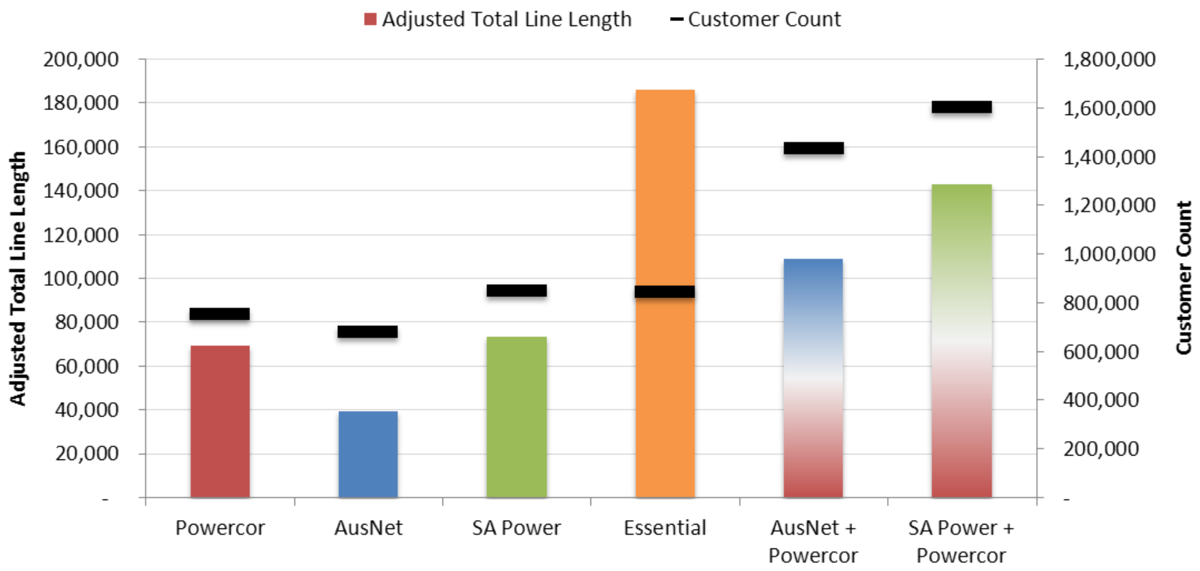

Figure 7-6: Adjusted total line length and customer counts of DNSP's.

Attachment 7.4 demonstrates that when benchmarked and normalised by assets, Essential Energy does in fact compare favourably to its AER selected peers and that the proposed operating expenditure of $2,331 million ($2013-14) is both prudent and efficient.

In most instances, the AER used a per customer basis, or equally as biased against rural DNSPs a consumption or demand basis, to make comparisons in its benchmarking analysis. This was despite many statements from the AER and stakeholders pointing out the obvious bias in using such an approach including:

> *CCP view is that every business will be better on some measures and worse on others…*[319]

and

> *Per customer PPI metrics tend to (on balance) favour urban service providers over rural providers as, typically, rural service providers will have more assets per customer because their customers are more spread out. We must bear this in mind when we consider the results in Figure A-2. In particular, Essential Energy has a very low density network so it will appear to perform worse…*[320]

and

> *Given 'per customer' metrics tend to favour higher density service providers, we must bear this in mind when comparing Endeavour [sic] Energy to these businesses.*[321]

and

> *When making comparisons on 'per kilometre' metrics against customer density, we need to bear in mind that service providers with low customer densities should appear more favourably than those with high customer densities. Lower density service providers are typically larger networks with many kilometres of line to serve sparsely located customers. While this generally means they tend to have high 'per customer' costs, they also have low 'per kilometre' costs. 'Per kilometre' metrics, therefore, typically favour rural service providers over urban service providers.*[322]

The comparisons used by the AER reveal nothing as to the relative efficiency of the DNSPs included, they merely illustrate the significant differences between the operating factors impacting each DNSP.

The AER go on further to confirm the flaws in its assessment approach when it stated:

> *…Essential Energy appear to have very high costs relative to most service providers. These results are consistent with our economic benchmarking. Although Essential Energy has very low customer density, and some of the observed cost differential will be due to that, we consider that it is still appropriate to compare it to other service providers with predominantly rural service areas or which cover very large territories, such as SA Power Networks and Powercor. Further, given the results of the economic benchmarking, it is unlikely that the large gap between Essential Energy and these other rural service providers can solely be due to customer density.*[323]

The statement above points to some issues with its benchmarking but fails to go any further and then the AER makes no attempt to investigate the causes of the cost differential. The AER thinks some of the differential may be due to customer density but cannot be sure how much, but concludes without any evidence or basis that any cost differentials between incomparable DNSPs is probably not solely due to customer density.

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[319] CCP, *Consumer Challenge Panel response to NSW electricity DNSPs' Regulatory Proposals*, Presentation at AER public forum, 10 July 2014, slide 7.

[320] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p31.

[321] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p79.

[322] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p81.

[323] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure,* November 2014, p79.

This statement also highlights another severe flaw in the AER's benchmarking analysis; the constant inappropriateness of the DNSPs that Essential Energy is compared to. An example of the incompatibility is set out below:

> *This is consistent with AGL's view in its submission on the NSW service providers' regulatory proposals. AGL noted that although there are operating environment factors that may explain some of the differences between service providers' operating expenditures, it is unable to understand why Essential Energy has a cost per customer twice that of AusNet Services which is similarly required to cover a large region.*[324]

Unlike the statement above made by AGL and repeated by the AER, Essential Energy does not cover a similarly large region to AusNet Services, but in fact covers an area over nine times that of AusNet Services and has circuit kilometre line length over four times that of AusNet Services. One could therefore draw several different, but equally simplistic, conclusions based on the actual facts when comparing Essential Energy to AusNet Services in contradiction to the AER's conclusion, for example:

- Essential Energy cannot be compared to AusNet Services due to the significant differences in operating factors; and
- With costs per customer only twice those of AusNet Services but covering an area over nine times as large with at least four times the amount of circuit length, Essential Energy appears to be at least twice as efficient as AusNet Services.

To further demonstrate the inappropriate comparisons made between Essential Energy and other DNSPs by the AER, the sections below set out some basic facts on the differences between Essential Energy and DNSPs in Victoria and South Australia that demonstrate the comparisons used by the AER are flawed.

The AER's analysis of historical operating expenditure compares Essential Energy to a combination of Powercor and SA Power Networks (SAPN). The AER concludes the following in relation to our operating expenditure based on this analysis:

> *Figure A-3 shows some very simplistic direct comparisons to put the NSW service providers' historical opex spending into perspective. We compared the NSW service providers to combinations of other service providers to show that for similar levels of opex it is possible to produce greater amounts of outputs. Where possible we have compared the NSW service providers to a combination of service providers with similar characteristics…*
>
> *…*
>
> *Similarly, …Essential Energy spent largely comparable amounts of opex to a combination of two Victorian or South Australian service providers despite (in all but one measure) providing less outputs. While these simplistic comparisons do not account for differences between the service providers, they support evidence of material inefficiency shown by our more sophisticated benchmarking techniques and our detailed analysis.* [325]

Essential Energy's predominant cost driver is the assets we must safely operate and maintain, customers and demand have very little cost driver influence on operating expenditure The AER has admitted in the above that its comparison is simplistic but then goes on to find two DNSPs whose operating expenditure add to a similar level as Essential Energy and compare output measures of customers, circuit length and demand. The AER concludes that because Essential Energy was lower on output measures of customers and demand but higher on circuit length it

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[324] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p66.

[325] AER, *Draft Decision Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p36-37.

supports their view that we materially inefficient. Given Essential Energy's predominant cost driver has a much closer poxy to line length than it does to customers or demand, the AER's analysis does not support any conclusions on relative efficiency.

Chapter 2 of this proposal provides some useful comparisons and provides context around Essential Energy's operating environment and environmental factors. Upon assessment of the vastly different operating variables of peer networks, it is not reasonable that Essential Energy operates under similar global levels of operating expenditure when Essential Energy's network contains many more assets and circuit kilometres which are substantially longer. Circuit kilometres can be used as a proxy for the number of assets, which as described above is a significant driver of operating expenditure for Essential Energy. When taking into account the AER's draft decision on operating expenditure, the allowance determined is substantially below prudent and efficient levels when taking into account cost drivers.

A similar observation can be made when examining the analysis carried out by the AER in relation to the adjustment of our base year operating expenditure as a result of economic benchmarking. The AER compared Essential Energy to a weighted average of all DNSPs with efficiency scores above 0.75, including CitiPower, Powercor, United Energy, SAPN and AusNet Services when deciding the quantum of adjustment needed. The AER also provided an additional ten per cent allowance to account for operating environment differences not captured by its preferred economic benchmarking model.

Like the simplistic benchmarking described above, the AER's economic benchmarking techniques took a biased approach to benchmarking Essential Energy by using output measures and weights that do not reflect the predominant cost drivers and the significant services provided to our customers. As described above, customer numbers, consumption and demand are not outputs that drive operating expenditure for Essential Energy. Essential Energy's operating expenditure is primarily applied to safely operating and maintaining assets. Despite this, the AER and their consultants EI decided the appropriate mix and weightings of outputs to use in their MTFP and MPFP analysis was heavily weighted to consumption, demand and customer numbers with line length given little weight.

Table 7-7 provides a summary of key facts on characteristics of DNSP's. As shown, Essential Energy operates and maintains a network that is only 14 per cent shorter over an area covering almost twice that of a combined South Australia and the four Victorian DNSPs, yet we are only spending half as much on operating and maintaining the network. The AER's draft decision concludes that this means Essential Energy is materially inefficient and decides a cut in base year operating expenditure of 35 per cent is appropriate. Effectively this means that Essential Energy would then have to maintain its network that extends to 86 per cent of the lines over twice the area of a combined SAPN and the four Victorian DNSPs with only 36 per cent of the operating expenditure.

Table 7-7: DNSP Network Facts[326]

	Customers	Line Length (circuit kms)	Area (km²)	Consumption (GWh)	Demand (MW)	12-13 Network Services Opex ($13-14, millions)
Facts						
Essential Energy	844,244	191,107	737,000	12,291	2,294	417
Powercor	753,913	73,889	150,000	10,556	2,396	194
AusNet Services	681,299	43,822	80,000	7,501	1,877	186
United	656,516	12,837	1,472	7,856	2,077	124

326 Sourced from the AER's State of the Energy Market 2014 and RIN templates.

	Customers	Line Length (circuit kms)	Area (km²)	Consumption (GWh)	Demand (MW)	12-13 Network Services Opex ($13-14, millions)
CitiPower	322,736	4,318	157	5,981	1,493	56
SAPN	847,766	87,883	178,000	11,008	2,915	231
All exc. Essential	3,262,230	222,749	409,629	42,902	10,758[327]	791
Ratios						
Ess:Powercor	1.12	2.59	4.91	1.16	0.96	2.15
Ess:AusNet Services	1.24	4.36	9.21	1.64	1.22	2.23
Ess:United	1.29	14.89	500.68	1.56	1.10	3.37
Ess:CitiPower	2.62	44.26	4694.27	2.06	1.54	7.44
Ess:SAPN	1.00	2.17	4.14	1.12	0.79	1.80
Ess:All exc. Essential	0.26	0.86	1.80	0.29	0.21	0.53

Table 7-7 demonstrates issues arising from the selected output measures and weightings. It is not surprising that the AER's determined base year operating expenditure for Essential Energy in relative terms is close to the ratios depicted for customer numbers, consumption and demand in Table 7-7 as these were the most heavily weighted in the model specification outputs. However, as discussed earlier, a more relevant output for Essential Energy is circuit length due to it being a significant cost driver for our business.

Given Essential Energy only has 26 per cent of the customers who consume only 29 per cent of the energy consumed when compared to the combined total of SAPN and the four Victorian DNSPS, and that line length is a much more relevant factor to Essential Energy's operating environment, customers and energy consumed should not be a relevant or material consideration in deciding the necessary operating expenditures of Essential Energy. What is relevant is that Essential Energy is required to safely operate and maintain a network that is almost the same length over twice the area of SAPN and the four Victorian DNSPs, However, the AER has determined an operating expenditure allowance that is 36 per cent of the combined businesses operating expenditure without any evidence on how Essential Energy can deliver such reductions whilst maintaining and operating a safe and reliable network. This conclusion highlights the absence of checking that benchmarking outcomes are reasonable as discussed earlier.

The AER provide a ten per cent allowance to Ausgrid, Essential Energy and Endeavour Energy to account for operating environment differences in its draft decision. Table 7-8 provides a sensibility check that demonstrates we operate very different networks that are materially incompatible. If environmental factors and operating environments had been considered in more detail by the AER, it would have determined different adjustments for each business taking into account important cost drivers.

[327] This summation is a guide only as to the quantum of the non-coincident maximum demand as the coincident maximum demand across the 5 SA and Vic DNSPs here is unknown.

Table 7-8: NSW DNSP Network Facts[328]

	Customers	Line Length (circuit kms)	Area (km²)
Facts			
Essential Energy	844,244	191,107	737,000
Ausgrid	1,635,053	40,964	22,275
Endeavour	919,385	35,029	24,500
Ratios			
Ess:Ausgrid	0.52	4.67	33.09
Ess:Endeavour	0.92	5.46	30.08

As shown in Table 7-8, each network is substantially different, however the AER concluded:

> *We are satisfied that the total operating environment adjustment to the efficiency scores for Ausgrid, Endeavour Energy and Essential Energy should be positive 10 per cent. We consider that it is appropriate to take a more holistic view of the possible effects of operating environment factors on the NSW service providers' opex. As a result, we have used the operating environment adjustments identified as an indication of the total impact that operating environment factors may have on these service providers' costs.* [329]

Despite the AER's proposition that it took a holistic view, the facts would point one to believe that a simplistic and unrealistic view was taken. Any holistic view would clearly point to a large differential existing between the operating environments of the three NSW DNSPs. For example, excluding vegetation management costs, Essential Energy receives less operating expenditure (and similar replacement capital expenditure) compared to Endeavour Energy in the AER's draft decision for a network that is 546 per cent longer with 450 per cent more distribution substations.

The AER has purported to undertake a comparison of our vegetation management costs by benchmarking us relative to other DNSPs in the NEM. It has formed a view that we have slightly higher costs relative to Ergon, Powercor and TasNetworks, and provided a graph which showed our relative cost compared to customer density. 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 are inefficient. Indeed we consider that this reveals broader weaknesses in the AER's benchmarking approach to reviewing our proposal.

In Attachment 7.10 we make the following observations. First, we note that the AER has not identified the standards that other DNSPs may apply, or if they are achieving compliance with those standards. We therefore consider it unreasonable in the absence of this evidence to compare our performance to these DNSPs, and to have our costs reduced to their level.

> *…the AER's analysis is highly flawed and does not show a reasonable basis for forming a conclusion that our vegetation management costs are inefficient.*

[328] AER, *State of the Energy Market 2014*, 19 December 2014.
[329] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 7: Operating Expenditure*, November 2014, p104.

Second, 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 ensure they meet a prudent standard. We consider it is unreasonable to compare our forecasts on this time series, given that a business such as Powercor have more than tripled spending between 2009 to 2013, as shown in Table 7-9.

Table 7-9: Total vegetation management expenditure by Victorian DNSPs 2009 to 2013 ($ million, nominal)[330]

Actual ($000s nominal)	2009	2010	2011	2012	2013	Change from 2009 to 2013
CitiPower	960	1,014	2,601	4,908	2,308	140%
Powercor	14,001	9,959	26,901	40,520	45,144	222%
Jemena	884	1,086	2,291	4,629	4,405	398%
AusNet Services	23,567	21,490	24,487	32,686	38,883	65%
United Energy	4,057	4,972	9,895	15,026	14,029	246%

Third, the AER's method of normalising costs by using customer density to reflect differences in operating conditions is not an adequate basis for accounting for the different environments and networks that DNSPs operate. The AER has dismissed the view put forward by Essential Energy that NSW has topographical features that increase our costs of delivering bushfire mitigation. The AER has unreasonably pointed to data which shows that Victoria have more bushfires, and therefore concluded that this means our vegetation management expenditure should be lower.

Evidence to show why vegetation management costs were required

The vegetation management costs proposed by Essential Energy were prudent, efficient, and at a sustainable level that will allow Essential Energy to meet its statutory obligations. The AER's draft decision details conclusions and expresses opinions relating to Essential Energy's proposed vegetation management expenditure, but excludes proposing an alternative amount of expenditure related specifically to vegetation management. Instead, it determines an alternative allowance at the total level.

This revised proposal demonstrates that the AER's opinions regarding the prudency of Essential Energy's vegetation management expenditure in relation to its statutory obligations to maintain vegetation clearances and minimise exposure to bushfire risk are also mistaken. We contend that the environmental factors that have a bearing on Essential Energy's exposure to bushfire risk are also very similar to those of its peer DNSPs in Victoria, Tasmania, and South Australia, rather than Ergon Energy in Queensland.

Redundancy costs

The AER applies a concept termed 'step change' to identify expenditure items that do not relate to a rate of change driven by output, productivity, or real cost escalation. The AER only accept a step if it is to comply with regulatory obligations, or to capture the impact of the forecast capital expenditure program on operating expenditure.[331] The

[330] Sourced from 2013 Category Analysis RINs

[331] The AER state in the Expenditure forecast assessment Guidelines that; "Regulatory obligations or requirements may change over time, so a NSP may face a step up or down in the expenditure it requires to comply with its obligations. Another important consideration is the impact of the forecast capital program on operating expenditure (and vice versa), since there is a degree of substitutability between capital expenditure and operating expenditure. A NSP may choose to bring forward the replacement of certain assets (compared to its previous practice) and avoid maintenance expenditure, for example."

AER considered that our forecast redundancy costs do not meet its criteria of a step change. The AER also found that there is no evidence to support an increase in maintenance from a reduction in the capital expenditure. We address these concerns below.

Our proposal included forecast costs relating to termination payments for redundant staff. The AER concluded that the cost did not relate to a change in obligations, or from a consequence of changes to capital expenditure. 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 draft decision as:

> The AER's mechanical use of a 'step change' definition has led the AER to incorrectly reject costs that meet the operating expenditure criteria of efficiency and prudency. [332] The term 'step change' is not used in the Rules, and is a concept that only 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. Redundancy payments relate to the excess labour resulting from efficiency programs. The efficiency programs have led to significant reductions in our operating expenditure 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. Essential Energy has included a labour productivity rate in this revised proposal of five per cent per annum which equates to 945 full time employees leaving the business over the 2014-19 regulatory period, and results in a permanent reduction in our costs for the long term benefit of customers.

> We have legally binding obligations to provide redundant staff with termination payments under existing Fair Work Commission certified awards and contracts.

Change factors

Output growth

In our initial proposal, we had proposed an increase for output growth of $31 million ($2013-14). Based on its own formula comprising ratcheted maximum demand, customer numbers and circuit length, the AER consider that our proposed growth factor was too high and it subsequently substituted its own lower amount.

We have considered whether the AER's output growth factor is a better basis for determining our increase in operating expenditure from the base year. Based on our review, we consider there is no basis for revising our proposal for the following reasons:

> The AER's draft decision is based on being consistent with its untested and unreliable benchmarking analysis.

> Essential Energy's method is based on its asset growth from capital expenditure, which increases the size of the network and subsequently the number of assets to be operated and maintained. This method is exactly the same as that used and accepted by the AER in its 2009 final determination for Essential Energy.

Essential Energy's Asset Growth escalation model is provided at Attachment 7.11.

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 clause 6.6.6 of the Rules. Our proposal noted that operating expenditure/capital expenditure substitution possibilities are a relevant operating expenditure factor, and that this is a fundamental aspect of a prudent forecast method. We showed that our proposed costs had included an increase

[332] We note that we had previously raised issues with the AER as part of Networks NSW response to the Expenditure forecast assessment Guidelines.

of maintenance costs to reflect the expected deterioration in our assets as a result of reductions in our capital expenditure 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 method of averaging its real labour escalators from Deloitte with our proposed real labour escalators from CEG updated for the latest information available from CEG. We have not revised our proposal to incorporate the AER's draft decision on real materials escalators but have updated them based on the latest information from CEG. This is discussed further in the sections below.

Productivity

The AER has applied a productivity factor of zero when assessing the forecast of operating expenditure 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 initial proposal incorporated efficiencies in the 2014-19 regulatory period related to our internal and NNSW 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.

> *…our forecast method had already captured productivity growth through our efficiency programs.*

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 assess whether our proposal for the 2014-19 regulatory period represented the efficient costs of achieving the operating expenditure 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 operating expenditure in each year of the 2014-19 regulatory period was efficient, and satisfied the operating expenditure criteria.

> *… our proposal incorporated productivity improvements well in excess of the industry average based on the AER's benchmarking.*

Overheads

Essential Energy rejects the AER's assertion that overheads are "very high" and maintains that the revised proposal contains the appropriate level of overhead expenditure to deliver its services safely and reliably.

Attachment 6.4 outlines how the size, scale and geographic dispersion of our network impacts on our overhead costs. Key overhead functions that have a strong relationship to the size of the network include:

- Our regional management and depot operations structure required to effectively manage the 3,000 field based employees.
- Property, which includes operating and lease costs for about 140 operational sites and a further 287 radio sites across Essential Energy's footprint.
- ICT costs relating to supporting IT infrastructure, complex architecture and range of technologies required to support these sites.
- The technical and safety training required for field based employees.
- Network control room, outage management and supply interruption functions all to manage network fault and emergency across a vast network exposed to challenging environmental conditions.

The benchmarking undertaken by the AER does not adequately adjust for the differences between a geographically dispersed rural network and an urban network. Robust benchmarking is further impeded by inconsistent cost categorisation and capitalisation policies, as well as inconsistent data within the RINs.

Our analysis also identifies issues with the inconsistent approach the AER has taken on adjusting overheads across different control services. This outcome cannot be implemented in line with our AER approved CAM.

Revisions to our proposed operating expenditure

As noted above, we have reviewed the AER's draft 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 shortcomings 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 operating expenditure criteria.

> *… the AER had not applied a proper method to review these [vegetation management, labour inefficiencies and redundancy] costs, and that we remain satisfied that our methods satisfied the operating expenditure criteria.*

In reviewing the AER's reasons, we also examined whether there was any new information that impact on our revised proposal. We have revised our proposal to incorporate the latest information on labour productivity, estimates of vegetation management costs, and labour cost escalators.

Revisions to our initial proposal

We have revised our initial proposal for matters that the AER has reviewed in making its decision. Based on these reviews, we have been mindful of examining the latest data and information that has come to light since submitting our proposal. We have made the following revisions in light of this information:

- A decrease in operating expenditure of $132 million related to labour productivity improvements.
- An increase in operating expenditure of $26 million due to a change in the allocation of some fixed divisional and corporate overheads as a consequence of reduced capital expenditure.
- An increase in operating expenditure of $67 million to reflect additional vegetation management, the rectification of non-compliant clearance levels, and rectification of urgent network defects identified since the introduction of LiDAR technology.
- An increase of $30 million in operating expenditure to reflect redundancy costs associated with transforming our business 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.

The impacts of these changes can be seen in Figure 7-7.

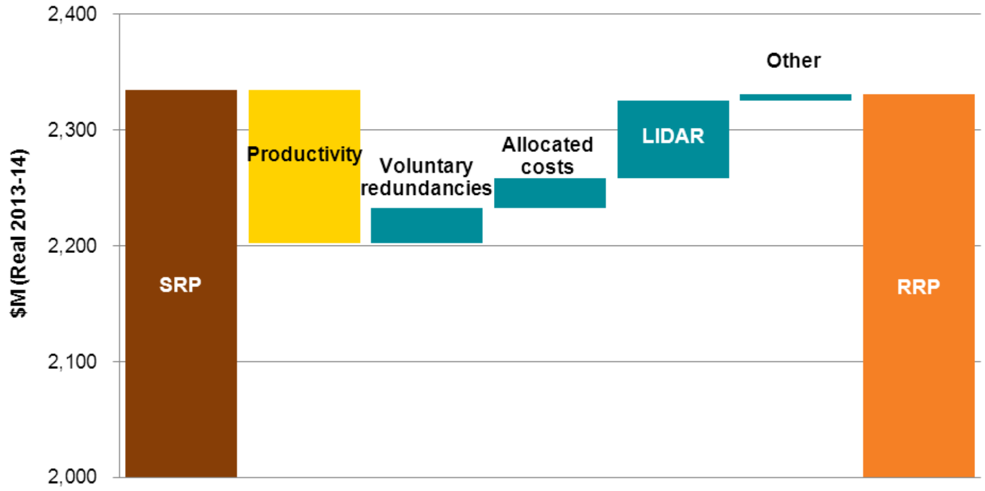

Figure 7-7: Movements in operating expenditure from SRP to RRP

Our revised proposal for standard control services operating expenditure for the 2014-19 regulatory period is $2,331 million as shown in Table 7-10.

Table 7-10: Forecast operating expenditure over the 2014-19 regulatory period ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Inspections	33	34	32	33	31	163
Maintenance and repair	80	81	78	80	74	394
Vegetation management	167	160	139	141	129	737
Emergency response	81	82	79	81	75	398
Other network costs	132	129	121	119	114	615
Total network costs	**493**	**487**	**450**	**454**	**422**	**2,307**
Debt-raising costs	4	4	4	4	5	22
DMIA	1	(0)	1	1	1	2
Total forecast operating expenditure	**498**	**491**	**455**	**459**	**428**	**2,331**

Note: numbers may not add due to rounding

Why our proposed operating expenditure better satisfies the operating expenditure objectives

We do not consider the revised forecast operating expenditure is materially different from our initial proposal. Our changes mainly relate to updated information on our labour productivity, vegetation management costs, non-compliant clearance levels, reallocated labour costs and labour cost escalators.

As such, the reasons outlined in the initial proposal as to why we consider our forecast satisfies the operating expenditure objectives, criteria and factors remain valid. Attachment 5.3 to our initial proposal and the ‘meeting the Rules’ section of that 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 operating expenditure criteria relative to the AER’s substitute approach. Our forecast method used actual costs in 2012-13 as a starting point to derive an efficient forecast of operating expenditure. We demonstrated that we had responded to the incentives designed by the AER to reduce our operating expenditure to levels below the efficient allowance set by the AER in its 2009-14 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 operating expenditure for the 2014-19 regulatory period.

…the AER's substitute approach did not enable it to undertake a proper examination of whether its substitute amount satisfies the operating expenditure criteria.

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 substitute operating expenditure. However, its decision must reasonably reflect the operating expenditure 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 operating expenditure criteria. We consider that the AER should have considered:

- The activities we perform that incur operating costs. This would identify whether the activities are required to achieve the operating expenditure objectives.
- Whether the costs involved in delivering that activity are reasonable and reflect the efficient costs of doing so, with regard to Essential Energy's circumstances.

The AER's benchmarking analysis did not address the activities we perform, nor did the AER's review of our initial proposal. The only area where the AER identified a deficiency in the actual operating expenditure we incurred in 2012-13 has been labour and vegetation management costs.

In respect of labour costs we have demonstrated that there is no evidence to demonstrate that our costs are inefficient relative to peer DNSPs.

In respect of labour costs we have demonstrated that there is no evidence to demonstrate that our costs are inefficient relative to peer DNSPs. Indeed the only available evidence suggests that our labour costs are comparable to our peers. In any case, the AER has not considered that we could not simply change our labour costs overnight as these are subject to decisions by Fair Work Australia.

The AER's review of our vegetation management costs in 2012-13 has ignored data we provided which show that we proposed a step change down to reflect greater efficiencies in vegetation management. 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.

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…This has practical implications for safety and reliability.

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. The AER's substitute amount provides approximately 62 per cent of what we proposed. 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. 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 including:

- **Vegetation management** – Lower operating expenditure means that we would need to reduce compliance levels with our standards. In turn, this would lead to far higher risks 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. In the medium term a high cost backlog maintenance program would be required to re-establish the overhead line corridors due to vegetation growing out of control.

- **Emergency response** – Lower operating expenditure would increase the amount of time it takes to respond to outages on the network. This would impact the customer through increased interruption times. For businesses this would involve higher economic costs from outages.
- **Inspections, preventive maintenance** – Lower operating expenditure will increase the risk of outages on the network, and increase the probability of safety incidents. We have sophisticated maintenance planning tools (Failure Mode Effect & Criticality Analysis / Reliability Centred Maintenance or 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 higher costs to customers over the medium to longer term.
- **Corrective maintenance** – Lower operating expenditure means that we will be put in the position of spending a greater proportion of maintenance effort responding to asset failures rather than 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.[333]
- **Operating and controlling the network** – Lower operating expenditure would increase the risks of safety and reliability incidents as a result of lower resourcing of system operations (control room). It may also impact our ability to respond to faults in a timely manner, and reduce our effectiveness in planned scheduling of outages.
- **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, 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 forecast operating expenditure better satisfies the operating expenditure criteria relative to the AER's substitute amount.

Immediate adjustment to the AER's forecast operating expenditure not appropriate

We consider that the AER should accept our revised forecast operating expenditure for the reasons discussed above. However, if the AER was to determine that significant reductions in our forecast operating expenditure 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 operating expenditure, that provides for a realistic forecast of Essential Energy's actual costs while incentivising efficiency reductions over time in a realistic manner.

The AER must determine a forecast operating expenditure 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:

[333] Jacobs, *Networks NSW – Draft Determination Review, System Capex & Maintenance Prudency Assessment*, January 2015, p49.

- The efficient costs of achieving the operating expenditure objectives,
- The costs that a prudent operator would require to achieve the operating expenditure objectives.
- A 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 Essential Energy are discussed above.

Given the inherent requirements on Essential Energy to supply electricity safely, legally and reliably, any reduction in operating expenditure must be carefully planned and managed. This careful management and planning has been reflected in the efficiency programs that Essential 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.

Essential Energy is currently subject to the allowed revenue (and operating expenditure) under the transitional determination and, prior to that was subject to the allowed revenue (and forecast operating expenditure) under the regulatory determination for the 2009-14 regulatory period. Any sudden reduction in allowed revenue caused by a reduction in forecast operating expenditure such as that contemplated by the AER's draft determination has the potential to jeopardise the safety and reliability of Essential Energy's network as described above. A prudent operator would not take this risk given the potential consequences as explained in the statement by our Chief Operating Officer (Attachment 1.1). However, it would also be inconsistent with both the operating expenditure criteria and the NEO for the prudent operator for shareholders to bear the cost of the significant reductions in forecast operating expenditure because doing so may cause significant financeability risks to Essential 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 operating expenditure that (amongst other things) reasonably reflects the realistic cost inputs to achieve the operating expenditure objectives. It is not realistic for Essential 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 Essential Energy through the last regulatory period. Any adjustment to these costs to incentivise efficiency must also reflect the time that it would realistically take Essential Energy to implement them.

8. ALLOWED RATE OF RETURN

> - After careful review of the AER's draft determination on the allowed rate of return, we have proposed no major changes to our original submission.
> - We have serious concerns with the AER's proposed ten year transition path to the trailing average for the allowed return on debt as this would significantly under-compensate Essential Energy based on current forecasts and is inconsistent with relevant elements of the NEL.
> - We strongly contest the AER's approach to fundamental considerations such as efficient debt management, averaging periods, interest rate swap strategies as a state owned enterprise and return on equity.

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 changes 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 Essential 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 decision and its final rate of return guideline (guideline). We have also outlined areas of the AER's draft decision 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 this.

- We propose a rate of return of 8.85 per cent, commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Essential 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. This is well below the allowed rate of return for the 2009-14 regulatory period of 10.02 per cent 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 per cent, 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[334] rated Australian corporate bonds issued on 1 January 2004 to 31 December 2013. This is lower than the allowed return on debt of 8.82 per cent set in the 2009-14 regulatory 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 period. With the exception of the transitional arrangements and the choice of data service provider, this is consistent with Essential 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.

[334] 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+.

- 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 regulatory period, provide us with a reasonable opportunity to recover at least the efficient costs of debt finance, nor give rise to charges 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 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 Essential 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.
- As Essential Energy has historically issued debt on a benchmark efficient staggered portfolio basis and, the AER's proposed transition would significantly under-compensate Essential 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 regulatory 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 Essential 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 Essential 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 per cent, 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 regulatory period of 11.82 per cent 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 Essential 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 Essential Energy over the 2014-19 regulatory period.[335]

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) (Attachments 8.1 and 8.2),[336] Frontier Economics (Attachment 8.3),[337] SFG Consulting (SFG) (Attachment 8.4),[338] Professor Bruce Grundy (Attachment 8.5),[339] NERA (Attachment 8.6),[340] a letter from the Australian Office of Financial Management (Attachment 8.7)[341] 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) (Attachment 8.8)[342].

Additional details on Essential Energy's approach to the rate of return are set out in two reports from Competition Economics Group (CEG) titled Attachment 8.1: Efficient debt financing costs and Attachment 8.2: Estimating the cost of equity. 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 29 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 report in Attachment 8.4 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 Essential Energy.

The breakdown of our proposed rate of return is outlined in Table 8-1.

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335 As required by clause 6.5.2(c) of the NER.

336 CEG, *Efficient debt financing costs, January 2015 and CEG, Estimating the cost of equity*, January 2015.

337 Frontier Economics, *Cost of debt transition for NSW distribution networks*, January 2015.

338 SFG, *The required return on equity: Initial review of the AER draft decisions, Note for ActewAGL, Ausgrid Essential Energy and Endeavour Energy,* January 2015.

339 Letter from Professor Bruce Grundy to Justin De Lorenzo - 9 January 2015.

340 NERA, *Memo on Revised MRP estimates to 2013*, 14 November 2014.

341 Letter from Michael Bath of the Australian Office of Financial Management to Steve Knight regarding domestic interest rate swaps, 5 January 2015.

342 Statement from Group Chief Financial Officer, Networks NSW, January 2015.

Table 8-1: 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%

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.

Return on debt

The AER's draft decision has agreed to the position put forward by Essential Energy in our initial proposal that the allowed return on debt should be estimated using a 10 year trailing average approach that will be updated annually throughout the regulatory period. However, the AER's draft decision proposes to transition Essential 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 Essential Energy. The transition would, if implemented when rates remain at current levels, result in significant losses to Essential 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 customers of electricity.

The AER's draft decision did not accept our proposed approach to annually updating the cost of debt using data published exclusively by the Reserve Bank of Australia (RBA). The RBA is a highly reliable source of 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 Essential 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 Essential 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 Essential Energy based on the currently estimated cost of broad BBB rated debt, which 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 Essential 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. 2014-19 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 Essential Energy did not undertake the swap based strategy; Essential 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 Essential Energy's debt portfolio, which is confirmed by the analysis from UBS, Frontier and CEG.
- Essential 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.

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 that refinancing risks are relevant to consider setting the allowed return on debt because they have material implications for the financial sustainability of Essential 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. Essential Energy's determination for the 2009-14 regulatory 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 Essential 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 Essential Energy is outlined in Attachment 8.8: Statement from Justin De Lorenzo, Group CFO of Networks NSW, which operates across Ausgrid, Endeavour and Essential Energy. 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 that was applied by the NSW Businesses.*[343]

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.[344]

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 Essential 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.[345] On this basis, we consider that applying the trailing average approach should be used to estimate the allowed return on debt for Essential Energy over the 2014-19 regulatory period.

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 Essential 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 DNSP 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. Essential 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 Essential 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;

343 Statement of Justin De Lorenzo, Group Chief Financial Officer, Networks NSW.

344 UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p5.

345 AER, *Explanatory Statement, Final rate of return guideline*, December 2013 p109.

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 Essential Energy, and which are therefore irrelevant to Essential Energy ; and

c) Would produce a result for Essential Energy that does not permit Essential Energy to recover its efficient cost of debt.

There are no relevant "impacts" on Essential Energy or on customers of Essential 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 Essential 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 Essential 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:[346]

a) *"efficient benchmark service providers may have different efficient debt management strategies";*

b) *"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";*

c) 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;

d) "*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".*

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 Essential 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 5-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 Essential Energy.

[346] AEMC, *Rule Determination*, 29 November 2012, p84, 85, 86, 90.

The relevant benchmark efficient entity in the case of Essential 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 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 NEO 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,[347] 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 regulatory period and taking into account Essential Energy's final average 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.[348] 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.*

[347] CEG, *Efficient debt financing costs,* January 2015.

[348] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, p120.

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 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, Essential 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 Essential 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 (Attachment 8.3) and CEG (Attachment 8.1) clearly demonstrate that this is the basis of the AER's transition approach as set out in the draft decision.[349]

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 Essential 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 Essential 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 regulatory period, result in a net present value less than zero (i.e. NPV < 0) outcome by not allowing Essential 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 Essential Energy is not supported by the NER. The NER require a return on capital for each regulatory year of the 2014-19 regulatory 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 period (2014-15) and the efficient financing costs in the subsequent regulatory 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 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 regulatory period. To the extent there was any "over-compensation" in respect of the 2009-14 regulatory period, this has no impact on the efficient financing costs of a benchmark efficient

[349] Frontier Economics, *Cost of debt transition for the NSW DNSPs*, January 2015. CEG, *Debt financing costs*, January 2015.

entity in the 2014-19 regulatory 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 ten years.

Windfall losses to Essential Energy just from maintaining its benchmark efficient approach

Essential 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 Essential 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" for Essential 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 Essential 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 Essential Energy can, and consistent with the Law and the Rules must be, immediately transitioned to the trailing average cost of debt approach.

Table 8-2: Benchmark efficient return on debt v AER's transitional return on debt allowance

	2014-15	2015-16	2016-17	2017-18	2018-19	Average
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 as indicated to Networks NSW.

Table 8-3: Windfall loss on Essential Energy's notional debt portfolio due to the AER's debt transition

	2014-15	2015-16	2016-17	2017-18	2018-19	Average
Benchmark efficient debt portfolio	$4,072	$4,346	$4,620	$4,887	$5,152	
Under-compensation due to AER debt transition	$58	$63	$67	$69	$65	**$322**

Note: The notional debt portfolios are estimated as at the beginning of each financial year based on forecast capital expenditure 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.[350] Essential 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, Essential Energy would incur material costs to re-issue all of its existing debt over a short averaging period and then slowly refinance approximately 10 per cent of its debt portfolio each year for the next 10 years. To unwind existing debt

[350] SFG, *Rule change proposals relating to the debt component of the regulated rate of return, Report for the AEMC*, 21 August 2012, p52-58.

financing Essential 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 Essential Energy's existing debt portfolio as estimated at November 2014, was approximately $551 million. When this mark-to-market cost is combined with prevailing cost of debt for 10 year BBB debt, the total cost of matching Essential Energy's debt financing practices with those implied by the AER's debt transition would exceed even the windfall loss being faced by Essential Energy if it maintained its benchmark efficient debt strategy and the AER used the transition approach to setting Essential Energy's allowed return on debt for the 2014-19 regulatory 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 Essential 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 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 and 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.[351]

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, 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

[351] 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.

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 debt risk premium (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 Essential Energy These businesses' debt portfolios were, and still are, much smaller than Essential 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.

Essential Energy's ability to engage in interest rate swap strategy and costs of doing so

Essential Energy, along with the other NSW DNSPs requested that UBS AG Australia (UBS) analyse the cost and ability of Essential 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 Essential 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 Essential 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 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 Attachment 8.7 in a 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 Essential 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 even more weight to the UBS analysis, which concluded that it would not have been possible for Essential 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 DNSP's 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 Essential Energy to much greater interest rate risks than issuing fixed rate debt on a staggered portfolio basis as Essential Energy did. The staggered portfolio approach enabled Essential Energy to achieve the following efficient outcomes over the 2009-14 regulatory period:

- Diversified interest rate exposure across time (i.e. hedged interest rate risks)
- Managed refinancing risks on Essential Energy's significant debt portfolio.

Final averaging period was unknown

In addition to the fundamental inefficiency of a swap based approach for Essential Energy at the time of the previous determination, there was significant uncertainty about the actual averaging period that would apply to Essential Energy in the final determination. Essential 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 2 June 2008. This was the period originally proposed by Essential Energy and rejected by the AER as being too removed from the start of the regulatory period;
- 15 business days starting 2 February 2009 to 20 February 2009. This was the averaging period applied by the AER in its final decision – which was subsequently appealed by Essential Energy (Country 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.[352]

Any hedging that was actually carried out in or around the first two averaging periods would not have hedged Essential Energy's actual debt cost 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 Essential 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 (Attachment 8.1) on the efficient cost of debt.[353]

Therefore, in the circumstances of Essential Energy where the AER refused to accept Essential 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 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 Essential 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.*[354]

[352] See *Application by EnergyAustralia and Others* (No 2) [2009] ACompT 8, 69(k).
[353] CEG, *Efficient Debt Financing Costs*, January 2015.
[354] Associate Professor Lally, *Transitional Arrangements for the Cost of Debt*, November 2014, p28.

This statement is incorrect. All of the NSW DNSPs (and indeed the Queensland 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.*[355]

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 Essential 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 Essential 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 expected required net of the payment of 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 DNSP's were historically less aware of the full potential of swap markets. This statement is also untrue, which can be seen from the attached confidential statement from Justin De Lorenzo, Group CFO of Networks NSW. Essential 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 Essential 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 Essential Energy, which have been provided to the AER following information requests, include a range of permitted instruments including interest rate swaps.

Transition will expose Essential 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

[355] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (ND Revenue Regulation of Gas Services) Rule 2012: Rule Determination*, 29 November 2012, p87.

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 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 per cent 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 per weight to new debt cost 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,[356] entering into large volumes of swap transactions may be more difficult in future determinations.

Unlike other businesses, the NSW DNSPs including Essential Energy already issue debt efficiently on a staggered portfolio basis and will not have a base rate on interest that is floating at the time of the next regulatory period. In contrast to the businesses who have previously committed to a swap base strategy, the transition approach set out in the AER's draft determination exposes Essential Energy to interest rate mis-match risk and interest rate volatility. As outlined above, based on rates in February to June 2014, these would result in Essential Energy incurring windfall losses for having undertaken the benchmark efficient staggered portfolio approach.

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 of 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 Essential 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 (Attachment 1.8) demonstrates that these costs are actually quite significant.

UBS has estimated that due to the size of our debt portfolio Essential 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. $279million for Ausgrid, $109million for Endeavour and $133million for

[356] UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p13.

Essential), even before costs of additional liquidity premium and currency related volatility.[357] 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 DNSP's as estimated at November 2014 were approximately $1.92 billion (approx. $1.02billion for Ausgrid, $349million for Endeavour and $551million 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. $1.3billion for Ausgrid, $458million for Endeavour and $684million 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 Essential Energy relative to its efficient costs of debt finance. This would also place significant pressure on Essential Energy's financial sustainability over the 2014-19 regulatory 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 Essential Energy for its efficient cost of debt.

Choice of data service 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. 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.

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

[357] UBS, *Response to the Networks NSW request for financeability analysis following the AER's draft decision of November 2014*, January 2015, p12.

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.

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 per cent and has been updated since our initial proposal to reflect the most recent estimates of the historical average MRP (6.56 per cent) and the historical average real risk free rate combined with the latest forecast of inflation (4.77 per cent). 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 per cent. Incorporating updated data, the reasonable range for the benchmark for the purposes of this revised proposal is estimated to remain 10.1 per cent – 11.5 per cent.

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[358] 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.[359]

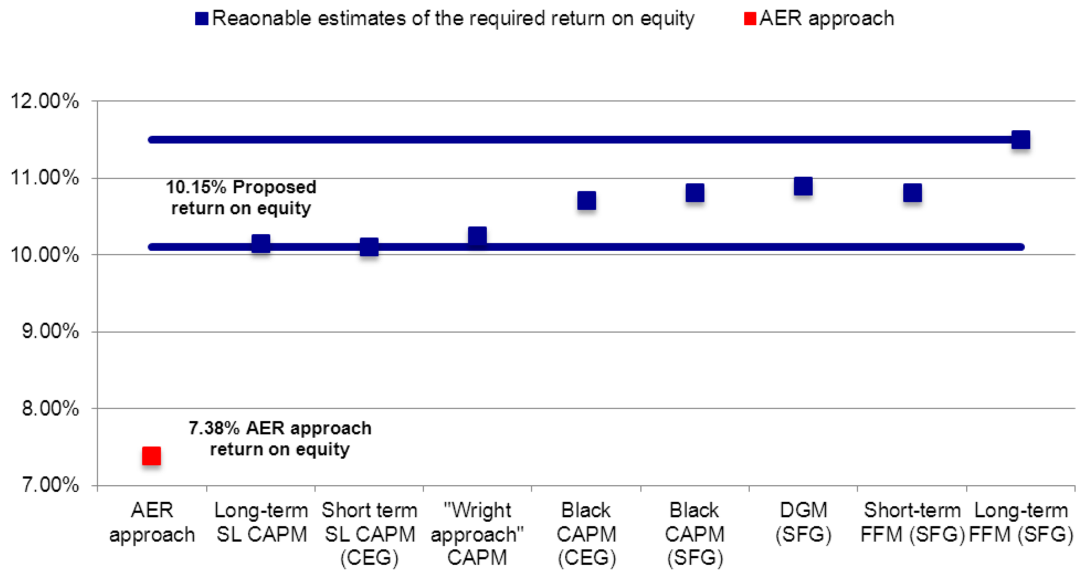

Figure 8-1: Reasonable range for the allowed return on equity

[358] As required by clause 6.5.2(g) of the NER.

[359] As required by clause 6.5.2(e)(1) of the NER.

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 updated estimates of the required return on equity estimated using the different relevant financial models.

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 per cent. 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 per cent 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 per cent using market data over the 20 business days to 19 December 2014.

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 regulatory 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 Essential Energy to nominate averaging periods for each year within its debt transition approach that were fully prospective. Within these constraints Essential 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 Essential 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 Essential Energy disagrees), Essential 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 2014-19 regulatory 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 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 inconsistency when applying the SL CAPM, the risk free rate used in the first part of the SP 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.[360] 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 marketing conditions

The draft decision stated that our proposed 4.8 per cent 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 per cent.[361] Clauses 6.5.2(e)(3) and 6.5.2(g) of the rules require an estimate of the benchmark efficient return on equity that has regard to the 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 the 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.

[360] Associate Professor Lally, *Review of the AER's methodology for the risk free rate and MRP*, March 2013, p26-27.
[361] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 3: Rate of return,* November 2013, p78.

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 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.

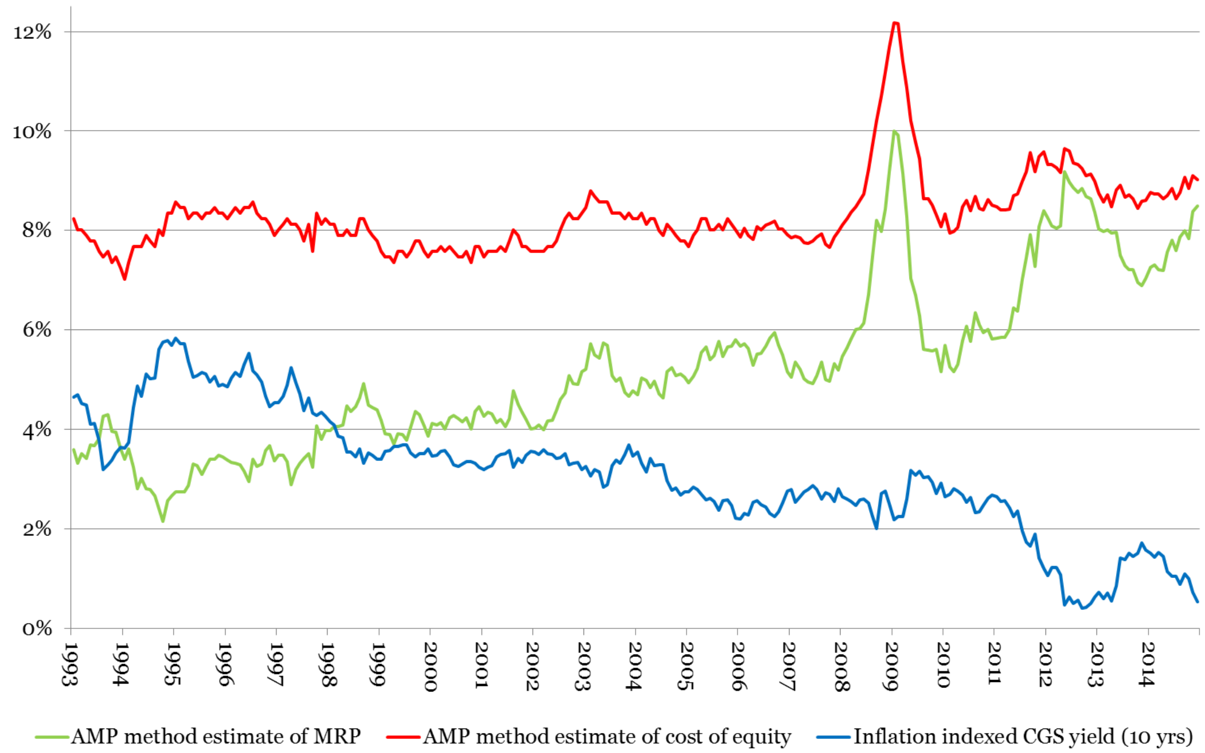

Figure 8-2: Movements in the real risk free rate, market risk premium and the real cost of equity over time

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 per cent (1883-2013)

> Expected return on the market of 11.33 per cent (1883 -2013)

> MRP estimate of 6.56 per cent (1883-2013).

Combined with an equity beta of 0.82 this provides an estimated cost of equity of 10.15 per cent.

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 per cent (using rates observed over the AER's initial debt averaging period, 28 February to 30 June 2014)

> MRP estimate of 7.48 per cent (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 per cent.

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 per cent 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.

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.[362] 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.

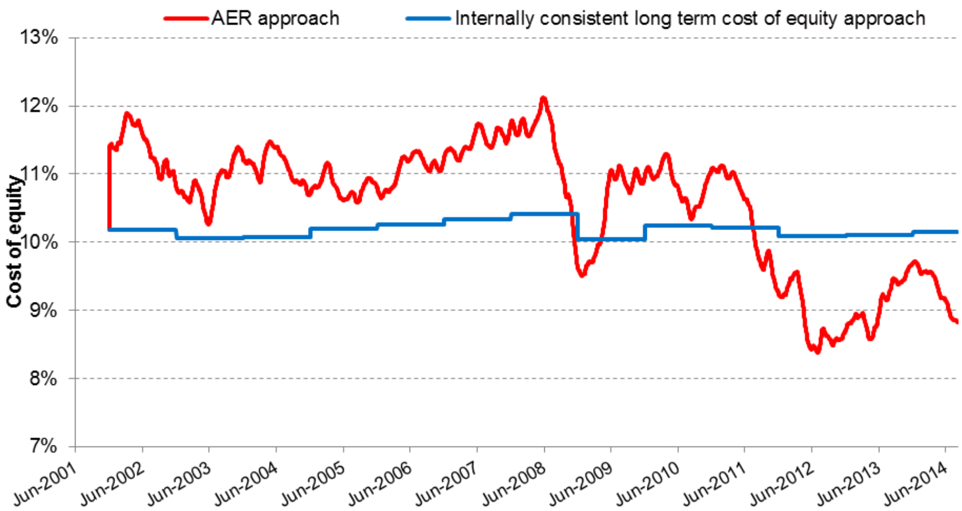

Figure 8-3: Historical cost of equity

Source: Essential Energy and NERA analysis.

The estimated risk free rate is at historic lows and combining this estimate with a long term MRP exposes Essential 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 per cent and in just two months from October to December 2014 the return on equity estimated using the AER's approach has dropped to 7.63 per cent. This is because the 10 year government bond rate has dropped from 3.55 per cent to 3.08 per cent (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

[362] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 3: Rate of return,* November 2013, p77.

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 per cent and the cost of equity to 7.38 per cent.

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 per cent 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 per cent 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 expected/required return on equities would likely increase to compensate investors for higher perceived risks in the market. CEG makes similar observations.[363]

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 per cent and our revised proposal incorporates an allowed return on equity 10.15 per cent. 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 per cent 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 estimates cost of equity for regulated network firms of 10.25 per cent during the AER's proposed averaging period for the initial return on debt observation.

Essential 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.[364]

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 proposal and supporting reports we outlined that Australian estimates of equity beta rely on a small sample of listed energy network firms (currently only four 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

[363] CEG, *Estimating the cost of equity, equity beta and MRP*, January 2015, - see especially Section 4 and Appendix A.
[364] ERA, *Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks – Revised Draft Decision,* 28 November 2014.

0.4 - 0.7 over time.[365] 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 Attachment 8.2: Estimating the cost of equity report from CEG.

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 Essential 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 per cent consistent with the AER's approach is actually 0.65 to 1.14.[366] Furthermore, as demonstrated by CEG, the 0.65 estimate relies on one year of data from two United Kingdom 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 two 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

[365] AER, *Draft Decision – Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 3: Rate of return,* November 2013, p243.
[366] We note that re-geared estimates were not possible to derive for estimates used by the Alberta Utilities Commission.

AER's benchmark gearing assumption of 60 per cent. 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:

- 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 one.
- 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.

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. 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 Essential 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 Essential 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.[367] 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 per cent using an averaging period for the expected return on the market and MRP of the 20 business days to 19 December 2014.

[367] McKenzie and Partington, October 2014, p25.

- 10.7 per cent 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 Essential Energy of 28 February to 30 June 2014.

SFG's updated cost of equity estimate using the Black CAPM is:

- 10.5 per cent using an averaging period consistent with the AER's cost of debt averaging period for Essential Energy of 28 February to 30 June 2014.

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.[368] 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:

[368] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p2.

…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 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.[369]

Professor Grundy also outlines that multi-factor models such as the FFM do have a strong theoretical basis, as outlined in Attachment 8.5. He notes that financial theorists view the empirically derived factors in the FFM as proxies for changes in investment opportunities.[370] 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.[371]

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 per cent using an averaging period for the risk free rate of 28 February to 30 June 2014.

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[369] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p3.

[370] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015, p3-4.

[371] SFG, *The required return on equity: Initial review of the AER draft decisions,* January 2015.

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.

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.

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.[372]

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

[372] Letter from Professor Bruce Grundy to Justin De Lorenzo, 9 January 2015.

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 over time compared with the AER's implementation of the SL CAPM, a point which has been recognized by the AER itself.[373]

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.[374] 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 per cent 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 per cent.

Table 8-4: Under-compensation from the AER's approach to the return on equity

	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	$97	$104	$111	$117	$124	**$552**

Note: This is based on an allowed return on equity under the AER's approach of 7.38 per cent (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 per cent.

Equity raising costs

In this revised proposal we maintain our initial proposal values for the various components of equity raising costs as outlines in our attached, revised proposal post-tax revenue model/s.

Value of imputation credits

The National Electricity Rules (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.[375] Essential 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).

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

373 AER, *Explanatory Statement, Rate of return guideline*, December 2013, p66.
374 SFG, *Report on the cost of equity for ActewAGL and Networks NSW*, January 2015.
375 NER, clause 6.5.3.

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 customers.

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 Essential 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 Essential Energy's original 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 8.9: Essential 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.

9. ALTERNATIVE CONTROL SERVICES

> We have not accepted the AER's decisions on charges for public lighting, ancillary network services and annual metering services.
> We believe the AER's approach is flawed in its rejection of our proposals on public lighting services, metering exit fees, and ancillary network services.
> Essential Energy firmly believes in the need to move to cost-reflective public lighting charges in order for these services to remain sustainable.
> Eventual revisions to costs, productivity and services levels are essential.

Summary

Essential Energy submitted cost reflective charges for the provision of alternative control services. For public lighting services and the newly classified metering and ancillary network services we sought to create simple, transparent and cost reflective charges.

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 determination

This chapter provides our response to the AER's decision on each element of our alternative control services proposal.

- Public lighting services – The AER did not accept our proposal on charges for public lighting. The AER's reasons were based on flawed analysis of our public lighting costs including lamp lumen depreciation, spot failure rates and the effect of escalating spot failures for the 4 year bulk lamp replacement cycle proposed by the AER. Our full response is set out below.
- Metering services – The AER did not accept our proposed charges for metering services. The AER removed the exit fee component of metering services from alternative control services by creating a new standard control service. The AER also made significant reductions in our proposed charges for metering services based on its conclusions that our replacement and operating costs were not prudent or efficient. We do not accept the AER's decision to re-classify exit fees to standard control services, and do not agree that our proposed metering charges did not reflect an efficient and prudent forecast of our costs. Our full response is set out below.
- Ancillary network services – The AER made substantial reductions to our proposed charges for ancillary network services. The AER stated that our labour costs were high, overheads were significant and that we had over-estimated the time taken to complete a service. We disagree with the AER's assessment and do not accept its draft decisions. Our full response is set out below.

Revisions to our proposal

We have only made consequential amendments to our initial proposal for alternative control services to incorporate revisions to our proposed allowed rate of return set out in Chapter 8 of this document.

AER draft determination

The AER's F&A paper classified public lighting, metering and ancillary network services as alternative control services. These services result in customers receiving an individual charge 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 charges for alternative control services.

The AER has not accepted our proposed public lighting charges. An alternative approach to metering has been included in the AER's draft determination to not approve the exit fee. A more administratively simple solution is available that would deliver lower metering charges to customers. 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.

Public lighting

In our initial proposal, we proposed significant increases to public lighting charges to correct significant long term under recovery of revenues when compared to efficient costs. In its draft decision, the AER rejected our public lighting charges. The AER states:

> *We do not approve Essential Energy's proposed public lighting charges because we consider some of the inputs into determining the level of charges do not reflect those of an efficient service provider.*[376]

In reaching its conclusion on Essential Energy's public lighting charges, the AER noted the following benchmarks to be appropriate:

- A 4 year bulk replacement program for lamps instead of the proposed 3 years
- Failure rates for the major lamp types of between 4 and 6 per cent per annum instead of a proposed average of 7.9 per cent
- 3 lamp spot replacements per day instead of the proposed 1.5 replacements per day
- Divisional and corporate overhead/indirect costs of 25 per cent instead of the proposed 41.25 per cent
- A real pre-tax WACC of 5.06 per cent instead of the proposed 7.09 per cent.

In reviewing the benchmarks determined by the AER to be appropriate, it is clear that an overall sensibility check on subsequent revenues is lacking. Essential Energy does not accept that the AER have provided adequate revenue to provide the required public lighting service. Table 9-1 below compares the draft determinations of Essential Energy and Endeavour Energy for the 4 most common light types on the Essential Energy Network. Tariff type 4 (Maintenance only post 2009) has been used as it does not include any historical influences and all equivalent lights regardless of tariff type should require the same maintenance. All lights are for a shared or no pole and standard outreach bracket.

In reviewing the benchmarks determined by the AER to be appropriate, it is clear that an overall sensibility check on subsequent revenues is lacking. Essential Energy does not accept that the AER have provided adequate revenue to provide the required public lighting service.

Table 9-1: Light type comparison of draft determination

Tariff 4 Light Type	Essential Energy Population	Endeavour Energy Draft Determination Rate per Annum[377]	Essential Energy Draft Determination Rate per Annum[378]	Variance %
HPS 70W	28,609	$73.34	$44.17	(39.8)%
HPS 250W	22,539	$74.89	$59.26	(20.9)%
MV80W	20,536	$71.50	$36.97	(48.3)%
42W CFL	55,274	$73.16	$47.18	(35.5)%

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[376] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 16: Alternative Control Services,* November 2014, p49.

[377] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 16: Alternative Control Services,* November 2014, Section A.1.3, p16-72.

[378] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 16: Alternative Control Services*, November 2014, Section A.1.3, p16-77. Note that reference to actual public lighting model is required due to an error in the published rates in the determination being in error for 2014-15 not 2015-16.

Table 9-1 clearly shows that on a like for like basis, the AER has determined a materially lower tariff for Essential Energy compared to Endeavour Energy. The AER is requested to review this decision. It is incongruous that both decisions can be correct and further supports the evidence in Attachment 9.1 that the Essential Energy public lighting revenue is well short of that required to provide the required service. The variance shown in table 9-1 draws significant doubt over the AER's draft decision and indicates that the draft decision may have been influenced more by concerns over increases in charges rather than the provision of an efficient and prudent revenue allowance commensurate with the provision of the required service.

Essential Energy's response to the AER preferred benchmarks is set out as follows. Further information and analysis is set out in Attachment 9.1 and summarised in table 9.2 below.

Table 9-2: Summary of AER Issues and Essential Energy response

Activity	Original Proposal	Draft Determination	Revised Proposal	Impact on Draft Determination
Bulk Lamp Replacement Cycle	3 year cycle	4 year cycle	3 and 4 year Hybrid cycle 16.47% luminaires remaining on 3 year cycle to be replaced with lumen 4 year compliant luminaires as appropriate	$377,078
Spot Failure Rates	Weighted average 7.91%	Weighted average 5.21%	Weighted average 8.78%	$1,743,537
Tasks per truck roll	1.5	3.0	3.0	Nil
Corporate Overheads	41%	25%	37%	$1,505,470
WACC	7.09%	5.06%	7.09%	$331,710
Total Revenue	$14,916,885	$9,426,490	$13,272,681	$3,846,191[379]

Four year bulk lamp replacement cycle

The proposed change by the AER to a four year bulk lamp replacement cycle will further increase the spot failure rate as lamp mortality will escalate in the 4th year of service life and requires the recalibration of the spot failure (attendance) rate for all purposes.

The proposed change by the AER to a 4 year bulk lamp replacement cycle will further increase the spot failure rate…

Essential Energy proposed a three year bulk lamp replacement cycle due to the mix of luminaires that have varying lumen output performance. A review of the luminaire types in the fleet has now been undertaken and we have identified that there are 16.5 per cent of luminaires remaining where lumen depreciation at four years would exceed that permitted under AS/NZS 1158. Essential Energy's revised proposal in this regard can be summarised as follows:

> Essential Energy is concerned that the AER have provided no Engineering basis for a unilateral change to a four year bulk lamp replacement cycle which will be non-compliant with lighting standards for some luminaires. There is no engineering basis provided by the AER for this position.

> 83.5 per cent of luminaires that can maintain compliant lumen output have been modelled at four years.

> 16.5 per cent of luminaires that cannot maintain the required lumen output at four years have been modelled at three years.

> Essential Energy will plan to progressively replace those luminaires that are non-compliant at four years as a hybrid three and four year cycle is not fiscally efficient. There will be some minor exceptions where no alternative is available. Once replaced the luminaires will adopt the appropriate light and tariff type.

[379] The individual impacts to not total to the total revenue impact as other immaterial factors reduce the total by approximately $112,000.

Failure rates for major lamp types

Essential Energy has analysed the failure rates determined by the AER. This analysis shows a weighted average spot failure rate of 5.21 per cent compared to Essential Energy's in service history from the Asset Management System of 7.9 per cent. In Attachment 9.1 we discuss failure rates in detail. The AER in their draft determination note that:

> *Endeavour Energy has achieved and is again proposing for the 2015–18 regulatory control period lower failure rates across its lamps of 4.46 per cent compared to Essential Energy (proposing 7.9 percent).*[380]

It is evident that the AER are confusing lamp failure rates with spot attendance rates for all purposes.

It is evident that the AER are confusing lamp failure rates with spot attendance rates for all purposes. The 7.9 per cent Essential Energy rate is for spot attendance for all purposes not just lamp failure. The Essential Energy rate compares favorably with 13.63 per cent for Endeavour Energy and 11.98 per cent for Ausgrid.

Essential Energy's revised proposal is that the spot attendance rate will need to increase from a weighted 7.9 per cent to 8.78 per cent to take account of the determined four year bulk lamp replacement cycle as lamp mortality rapidly increases in the fourth year of operation.

Number of lamp spot replacements (attendances per truck roll)

In its initial proposal, Essential Energy proposed an average of only 1.5 repairs per truck roll given the low density of luminaires. The AER pointed out that on a weighted basis the correct number of repairs per truck roll is 3. We accept the AER's decision in this regard for a weighted average failure rate of 7.9 per cent, however if:

- The Essential Energy revised failure rate, making allowance for a four year bulk lamp replacement cycle, of 8.81 per cent is rejected; and
- The AER adopts its draft decision as the final decision.

Then the weighted average number of repairs per truck roll on the AER's weighted failure rate of 5.21 per cent is three and as such will need to be recalculated accordingly in the tariff models.

Corporate overheads

The decision to insource or outsource operational support functions will impact overhead rates but may not reduce overall costs. By way of example, if Essential Energy were to outsource its operational functions, the overhead rate could be reduced to an estimated 18 per cent. This is because the current overhead required to support the insourced functions would instead be incurred by the contractor in the outsourced model. The outsourced costs would then be classified as a direct cost by Essential Energy upon receiving the invoiced amount; however it would also include the increased overheads of the outsourcing firm. While it may appear that overheads have reduced, it is really only a shifting of the reporting of costs from indirect (overheads) to direct.

In its draft decision, the AER rejected Essential Energy's Corporate Overhead allocation rate of 41 per cent and substituted a rate of 25 per cent. On review, Essential Energy does not consider this appropriate for the following reasons:

- The AER has not considered Essential Energy's CAM, previously approved by the AER. The AER's draft decision on the overhead allocation rate of 25 per cent is in conflict with the CAM. The CAM can be found at Attachment 6.5.
- The impact that an insourced versus outsourced business model can have on overhead rates must be considered. By way of example, if Essential Energy were to outsource its operational functions, the

[380] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 – Attachment 16: Alternative Control Services*, November 2014, p56.

overhead rate could be reduced to an estimated 18 per cent. This is because the current overhead required to support the insourced functions would be incurred by the contractor in the outsourced model and be classified as a direct cost by Essential Energy upon receiving the invoiced amount (which would be loaded with the contractors own internal overhead rate).

Further details on corporate and divisional overheads are included at Attachment 6.4 which unbundle the nexus to labour overheads and explains their application.

WACC

We have incorporated revisions to our proposed allowed rate of return as set out in Chapter 8 of this document.

Customer engagement

Essential Energy has continued to engage with Councils and Regional Organisation of Councils (ROCs) since it lodged its initial proposal. Chapter 3 provides further discussion on customer engagement in relation to public lighting and the formation of the Streetlighting Consultative Committee.

Revised proposal for public lighting

Essential Energy's public lighting service provided to local councils is significantly below cost reflective levels. For at least 10 years Essential Energy has not recovered sufficient revenues to compensate for the expense related to providing a public lighting service in accordance with obligations under the Public Lighting Code. Essential Energy is mindful of the impact on its customers of escalating charges, however the current situation is not sustainable. To ease the burden on customers, Essential Energy proposes to provide a service which aims to minimise costs and improve productivity. Our proposal is less than our current costs and will require improvements in productivity to achieve full cost recovery, however if the AER does not allow our proposed cost reflective charges for public lighting and the draft determination becomes the final determination, a reduction in service levels well below those set out in the NSW public lighting code will result.

For at least the previous 10 years Essential Energy has not recovered sufficient revenues to compensate for the expense related to providing a public lighting service in accordance with obligations under the Public Lighting Code.

To ease the burden on customers, Essential Energy proposes to provide a service which aims to minimise costs and improve productivity.

Public lighting services are classified as alternative control under the NER which means separate charges must be developed that clearly identify costs attributable to public lighting services. In effect, public lighting must operate as a stand-alone business with clear accounting separation from standard control services. This means that if public lighting charges are not set on a cost reflective basis, a shortfall in revenue will occur when compared to the costs incurred in providing public lighting services. Shortfalls in revenue cannot be offset through standard controls services.

Essential Energy's revised proposal provides an increase that is 16 per cent less than the revenue requested in our initial proposal. It is acknowledged that even after this reduction the tariff increases are still going to be substantial for some councils in order for Essential Energy to recover its efficient costs of running the Public Lighting business.

It is clear after feedback through the Street Lighting Consultative Committee that some councils would prefer a transition period for any increases over multiple years rather than a large step in the 2015/16 year. Essential Energy is prepared to work with councils to assist in managing the step change, provided the cost reflective revenue is fully recovered over the regulatory period. While Essential Energy's proposal is for cost reflective charges we welcome feedback from councils on any transition options that may reduce the initial increase but still return the full cost reflective revenue over the regulatory period. Essential Energy will continue to engage with councils and ROC representatives either directly or through the Streetlighting Consultative Committee, particularly in relation to revenue neutral transition options and any future reduction in service levels that may be required following publication of the AER's final decision.

Attachment 9.2 to this revised proposal contains Essential Energy's revised public lighting models and charges. Attachment 9.3 provides Essential Energy's proposed schedule of public lighting charges.

Metering Services

Our proposed charges for metering services were intended to provide a transparent, cost-reflective charging signal to customers whilst transitioning to an environment of increased competition. Charges were based on the meter service a customer was receiving. To develop cost reflective charges, historical costs were examined to determine the drivers of metering costs including recovering the costs of existing meters and new meters, as well as operating and replacement costs.

AER draft decision

The AER did not accept our proposed metering charges, believing costs were overstated and our exit fee was a barrier to competition. Specifically the AER stated:

> *To avoid creating a regulatory barrier to competitive entry, we do not accept Essential Energy's 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.*[381]

> *We accept Essential Energy's proposal to recover the capital costs of new/upgraded connections as upfront payments. We also accept its proposal to have a separate annual charge for new and upgraded customers, in recognition they have already paid for the capital costs for their metering installations.*[382]

> *We do not consider Essential Energy's forecast material unit costs to reasonably reflect the efficient costs of achieving the capital expenditure objectives or the costs of a prudent operator.*[383]

> *We accept a building block approach to setting charges but do not accept the following components of the Essential Energy proposal:*

- *The capital and operating expenditure*
- *The opening metering RAB.*[384]

> *We do not accept the remaining and standard asset lives proposed by Essential Energy… we do not consider that this accelerated depreciation is efficient.*[385]

Exit fee

The AEMC is currently in the process of formulating a rule change associated with the increased competition in metering, which will help facilitate a market led roll out of advanced metering. The AEMC provided that an appropriate, clearly defined and transparent exit fee for accumulation or manually read interval meters would be expected to

The AEMC provided that an appropriate, clearly defined and transparent exit fee for accumulation or manually read interval meters would be expected to encourage competition and more efficient investment in advanced metering.

[381] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative Control Services,* November 2014, p29.
[382] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative Control Services*, November 2014, p30.
[383] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative Control Services*, November 2014, p38.
[384] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative Control Services*, November 2014, p37.
[385] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative Control Services*, November 2014, p43.

encourage competition and more efficient investment in advanced metering[386]. In preparation for the AEMC rule change, associated with the increased competition in metering, Essential Energy proposed a metering exit fee comprising the residual meter cost and administrative costs associated with the transfer. The AER has rejected both components.

Residual metering costs

The AER rejected Essential Energy's proposed approach and charges on the basis that the exit fee (including recovery of residual asset cost and administrative charge) was anti-competitive. The AER has proposed that DNSPs be allowed to recoup the stranded costs created by competition at the time a customer obtains an alternate metering service provider, through the standard control mechanism. The existing metering asset base would be recovered from annual metering charges under Alternative Control. However, if the customer chose to have a third party meter replace the existing meter, an amount (equal to the residual value of the asset) would be recovered via an adjustment to standard control services. In its draft decision, the AER stated:

> *We reject Essential Energy's proposed exit fee. Specifically, we do not accept that Essential Energy should recover residual metering costs through an exit fee. Our alternative is to classify residual metering costs (the metering RAB component of annual charges that the customer would have paid had they remained a regulated metering customer) as standard control service and recover these through network tariffs.*[387]

Essential Energy is supportive of facilitating competition in metering services provided the AER has satisfied itself that this is not creating an artificially competitive market, and is a pragmatic, compliant and simple solution.

Essential Energy is supportive of facilitating competition in metering services provided the AER has satisfied itself that this is not creating an artificially competitive market, and is a pragmatic, compliant and simple solution.

As such, Essential Energy has revised its proposal to adopt the AER's approach and therefore excluded residual asset costs from the proposed 'meter exit fee'. We support the AER's draft decision to recover the residual cost via the B factor but not the characterisation of this recovery as a service or the creation of a new standard control service.

As outlined in Chapter 10 to this revised proposal, Essential Energy does not accept the AER's tolerance limit for the metering component of the b-factor adjustment. It is an efficient, approved cost that would form part of Essential Energy's standard control RAB, so it would be inappropriate to deny the recovery of this revenue if it were to exceed the 2 per cent limit. The timeline associated with the AEMC rule change process may result in material adjustments late in the 2014-19 regulatory period. It is proposed that all DUOS amounts be subject to one side constraint and one rule for the treatment of any under or over recovery, including the recovery of standard meter asset costs added to the standard control RAB.

Administration costs

Regarding the administrative component of the proposed exit fee, the AER has accepted the principle of a fee, specifically 'meter transfers', and has maintained the classification and control mechanism as an alternate control service. However, the AER rejected Essential Energy's proposed fee:

> *We classify the administration costs for type 5 and 6 meter transfers as an alternative control service.*[388]

and

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[386] AEMC, *Consultation Paper, National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2014 and National Energy Retail Amendment (Expanding Competition in Metering and Related Services) Rule 2014*, 17 April 2014, p.51.

[387] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p30.

[388] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 13: Classification of distribution services,* November 2014, p7.

> *We accept in principle that Essential Energy should be allowed charge an exit fee based on incremental administrative costs incurred to process a customer transfer. However, as Essential Energy did not adequately demonstrate they will incur incremental administrative costs, we are led to reject an exit fee based on administrative costs.*[389]

In response to the matters raised by the AER Essential Energy has reviewed the proposed administration fee and revised it. Specifically, we have sought to better understand and justify the activities involved in transferring a metering customer and the incremental costs involved.

Attachment 9.4 to this revised proposal contains detail on the 'meter exit (transfer) fee' cost build up.

In addition to our revised position, it is also noted 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 ancillary network services 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).*[390]

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.

We consider it unreasonable to have rejected our proposed fee and set it at $0 when an alternative, independent estimate was available.

Essential Energy has revised our metering services list of charges to adopt the decision to remove residual value of meters from the proposed exit fee. The meter exit fee now reflects the incremental administration and disposal costs associated with a customer switching to an alternate metering service provider. We believe this is also what has been referred to as "meter transfer fee" by the AER and Marsden Jacob but do not agree that it is a new standard control service fee.

Upfront meter charges

In determining the reasonableness of proposed charges for new or upgraded connections, referred to as the upfront meter charge, the AER analysed Essential Energy's unit cost.

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[389] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p47.
[390] Marsden Jacob Associates, *Provision of advice in relation to Alternative Control Services – CONFIDENTIAL version for NSW*, p20.

The AER rejected the upfront meter charges proposed by Essential Energy on the basis they were above the lowest rates identified by the AER's consultant, Marsden Jacob. Essential Energy has not revised its initial proposal to adopt the AER's alternative charges; however charges have been reviewed to ensure they represent a comprehensive and accurate list of available meters based on the most recent market information.

Material unit costs

Essential Energy does not consider the AER decision reasonable as it adopts the lowest cost meter in each range provided by Marsden Jacob. Marsden Jacob has not specified meter models or manufacturers; therefore it is unlikely Essential Energy can achieve these charges 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 low cost meters referred to by Marsden Jacob are of sufficient quality or reliability.

The acquisition of metering equipment is a long term decision with an asset life of 15 years… Determining the optimal cost position requires an accurate forecast of future failure rates.

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 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, thereby providing a lower and more efficient total replacement cost. Essential Energy has a high percentage of asbestos meter boards on its network. Maintenance activities that require drilling on an asbestos board requires specific procedures, resulting in increased time and associated labour costs. Essential Energy estimates that where drilling is required on an asbestos board an additional seven to 10 minutes is added to the meter replacement activities; equating to $14 to $21 (Field Worker R4 labour rate used) in additional labour costs. These costs must to be considered in determining the overall efficient costs of metering equipment.

Essential Energy considers that an efficient annualised cost has been achieved for all new metering equipment through the business's metering equipment procurement strategy. Essential Energy believes the economies of scale proposed by the AER are not realistic considering the volume of meters procured in NSW each year. The comparison to Victorian bulk procurement arrangements is irrelevant 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. nearly one million meters procured per year in Victoria during the recent smart meter rollout).

We consider that an efficient annualised cost has been achieved for all new metering equipment through our metering equipment procurement strategy.

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. While it is reasonable to provide customers the lowest cost option available, those who value quality, lower annual costs or have other priorities, should be afforded choice. Provided the charges set by the AER are cost reflective this decision should be left to the customer.

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.

Non-material unit costs

The AER in making their draft decision has also reviewed the non-material costs associated with meters, where non-material unit costs refer to the expenditure required to install, handle and manage the logistics associated with putting a new meter into service[391]. This definition differs slightly from Marsden Jacob's; non-material costs comprise of meter issuance, acceptance testing and other meter handling costs[392]. Non-material costs proposed by Essential Energy do not include costs associated with meter installation, as this work is presently performed by ASP's and funded directly by customers.

Essential Energy's proposed non-material unit costs were determined by applying the appropriate stores on-costs and overheads; these are applied to the meter charge on a percentage basis consistent with Essential Energy's CAM approved by the AER in May 2014.

> *Marsden Jacob has not considered the reasonableness of applying a percentage rate rather than a flat dollar fee and as such, we do not recommend any changes to the methodology adopted by Essential Energy in proposing non-material costs for new meters. However we recommend the average weighted per meter fees should equate to a maximum of $25.00 per meter.*
>
> *We note that Essential's proposed non-material costs include provision for overheads. In adopting a recommended average weighted cost of $25.00 per meter, we also recommend the treatment of overheads for this service should first be reviewed for consistency with Essential's Cost Allocation Methodology and the finding of that investigation be considered.*[393]

There is no indication provided by the AER that they have considered Marsden Jacobs recommendation in full and reviewed Essential Energy's non-material cost allocation in accordance with the CAM. Essential Energy has been consistent in our application of the CAM and applied stores on-costs and overheads on a percentage basis to the base meter purchase costs.

There is no indication provided by the AER that they have considered Marsden Jacobs recommendation in full and reviewed Essential Energy's non-material cost allocation in accordance with the CAM.

We have resubmitted our updated charge list for upfront metering charges reflecting the alteration to overheads, incorporating efficiency adjustments consistent with standard control services.

Annual Metering Fee

In determining Essential Energy's annual metering fee, the AER assessed Essential Energy's proposed capital and operating expenditure building blocks and opening metering regulatory asset base.

Capital Costs

In developing alternate annual metering charges the AER reduced Essential Energy's proposed metering capital expenditure program. Specifically, the AER stated:

> *We accept $50.3 million in capital expenditure for the 2014-15 and 2015-19 regulatory control periods and substitute that amount for Essential Energy's proposed $51.5 million ($2014/15).*[394]

In assessing the proposed capital expenditure, the AER reviewed 'unit costs' and 'volume forecasts'. The AER has generally accepted the proposed volume forecasts provided by Essential Energy.

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[391] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p39.

[392] Marsden Jacob Associates, *Provision of advice in relation to Alternate Control Services*, 20 October 2014, p17.

[393] Marsden Jacob Associates, *Provision of advice in relation to Alternate Control Services*, 20 October 2014, p19.

[394] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p37.

> *We accept Essential Energy's new or upgraded connections for 2014-15 and the distribution business' forecast replacement volumes.*[395]

The AER has reduced proposed capital costs; it would appear this reduction is based on the revised unit costs for metering hardware and non-material costs as determined within the Marsden Jacobs report. As mentioned above regarding up-front meter charges, Essential Energy does not accept that the cheapest meter provides the lowest total cost for new and replacement activities.

> *Essential Energy does not accept that the cheapest meter provides the lowest total cost for new and replacement activities.*

The AER has substituted the lowest end of the determined market rate range, as provided by Marsden Jacobs, as the prudent hardware price and adjusted the forecast capital expenditure accordingly. This is based on the assumption that ongoing procurement improvements by NNSW will lead to the lowest market price.

While price is one determining factor in our procurement process, this needs to be balanced with the ongoing operating costs associated with the metering equipment. Essential Energy considers the efficient annualised cost for all new metering equipment through our metering equipment procurement strategy, in an effort to procure metering equipment providing the lowest overall economic cost to the business and our customers.

> *While price is one determining factor in our procurement process, this needs to be balanced with the ongoing operating costs associated with the metering equipment.*

Essential Energy rejects the use of the lowest cost meter as being the most efficient overall economic cost; as such Essential Energy has submitted our revised proposal using meter procurement rates as per the original proposal.

A minor change has been made to Essential Energy's revised proposal to include a correction of unit rate for single phase accumulation meter purchases within the metering model.[396]

Operating Costs

In addition to the reductions to our proposed capital costs the AER have made significant reductions to our metering operating expenditure in establishing alternative charges. The AER has primarily relied on benchmarking to reject and substitute our proposed operating expenditure, specifically noting:

> *We approve $120.2 million in operating expenditure for annual metering services and substitute that amount for Essential Energy's proposed $131.3 million ($2014–15). This is an 8 per cent reduction from the proposed amount. However, our draft decision is based on an efficiency adjustment, rather than step change for special meter reads as Essential Energy proposed.*[397]

The AER recognises that Essential Energy's proposed operating expenditure per customer for the 2014-15 and 2015-19 regulatory periods performs well against historical results, but was concerned that most of this reduction related to the step change for special meter reads, rather than efficiency forecasts. The AER has therefore made an efficiency adjustment based on benchmarking results to the base operating expenditure.

> *Our benchmarking results shows Essential Energy's proposed operating expenditure to be overstated. To more reasonably reflect a relatively more efficient business running a network with Essential Energy's characteristics, we substitute the proposed base operating expenditure with an amount equal to Ergon Energy's per customer spend.*[398]

Essential Energy proposed $35 per customer, but the AER has substituted Essential Energy's proposed base expenditure with an amount equal to Ergon Energy's per customer spend, being $32 per customer.

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[395] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p39.

[396] Refer to response to information request AER *Essential 031_Metering Costs* provided on 16 October 2014.

[397] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p40.

[398] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p42.

Ergon Energy was considered to be a relevant comparator for Essential Energy as it has a similar customer density.

Table 9-3 below provides some relevant comparisons between Essential Energy and Ergon Energy. When looking at the comparisons below, it would appear reasonable that Essential Energy's efficient operating costs would be marginally higher than that of Ergon Energy:

> Essential Energy has a lower density of customers per kilometre

> Essential Energy has on average 1.86 meters per customer compared to 1.72 meters per Ergon customer

> Ergon has 10 per cent more customers residing within an urban environment, while Essential Energy has almost double the number of customers residing on a long rural feeder.

Table 9-3: Essential Energy – Ergon Energy Comparison[399]

	Essential Energy	Ergon Energy	Comparison
Customer Density	4.671	5.023	-7%
Customer Numbers	844,244	710,431	15.8%
Urban	196,664 / 23.3%	238,762 / 33.6%	-10.3%
Short Rural	513,663 / 60.8%	389,329 / 54.8%	6%
Long Rural	133,917 / 15.9%	74,368 / 10.5%	5.4%
Meter Numbers	1,567,809	1,222,528	22%

Most metering related services are performed at a customer's premises, for example meter reading and meter maintenance. Metering costs are inclusive of the time taken to attend site, as such are highly influenced by the location of customers.

Metering costs are inclusive of the time taken to attend site, as such are highly influenced by the location of customers.

Essential Energy had provided for a step change in its proposal, associated with metering services that are now classified as ancillary network services. Most of this step change related to the removal of special meter reads.

The AER has applied reductions based on the efficiency adjustment and is seeking to make further adjustments during the final determination.

> *Our substitute is marginally less than Essential Energy's proposal. However, our cut based on a benchmarking efficiency adjustment rather than Essential Energy's proposed step change. Our final decision which will include the step change for classification changes will therefore further reduce Essential Energy's metering operating expenditure.*[400]

Essential Energy is concerned the AER is seeking to apply further reductions to Essential Energy's metering expenditure by applying a step change for classification changes in the final determination. Essential Energy has no visibility of the quantum of the step change the AER will seek to apply. As it will be applied in the final determination, Essential Energy has had no opportunity to review and provide comment on this proposed step change within the revised proposal.

Regulatory Asset Base

The AER draft decision has revised the opening meter RAB value to $115.1 million.

[399] Source: AER published '*Essential Energy 2006-13 - Economic Benchmarking RIN - financial and non-financial information*' and '*Ergon 2006-13 - Economic Benchmarking RIN - financial and non-financial information*' and '*Ergon Energy 2012-13 - Annual Reporting RIN - non financial information*'.

[400] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p43.

> *We do not accept the opening metering RAB as at 1 July 2014 of $118.2 million ($nominal) as separated by Essential Energy from the RAB for standard control services (SCS). We have determined an opening metering RAB of $115.1 million ($nominal) instead.*[401]

This adjustment is associated with changes in the roll forward model for standard control services as discussed in Chapter 5 of this revised proposal. The AER made adjustments to our proposed value of the RAB as at 1 July 2014 (opening RAB values). We do not agree with these adjustments and have not incorporated the AER's opening RAB values in the calculation of our metering charges. It should be noted however, that the metering RAB value has decreased as a result of capital expenditure in 2013-14 being lower than forecast in the original proposal.

The AER has also rejected Essential Energy's proposal for accelerated depreciation of the metering RAB.

> *We do not accept the remaining and standard asset lives proposed by Essential Energy... We do not consider that this accelerated depreciation is efficient. It is unlikely that all meters will be provided by alternate service providers within 7 years.*[402]

Essential Energy proposed accelerated depreciation to remove legacy assets from the metering RAB as quickly as practical with the introduction of metering contestability. Essential Energy is unable to forecast the amount of churn that may occur due to installation of contestable meters on our distribution network over the 2014-19 regulatory period, however expect that a large proportion of existing metering assets will remain in place and operational at the end of the period. As such, Essential Energy has reviewed our proposed depreciation model for metering equipment and has accepted the AER's revised remaining useful life of 19.7 years with straight-line depreciation to apply over the standard life of 15 years for new asset additions.

Corporate overheads

Essential Energy has applied the average annual Corporate Overhead allocation rate to operating and capital expenditures. Further details on corporate and divisional overheads are included in Attachment 6.4 which unbundles the overheads and explains their application.

Control mechanism for metering

The AER draft decision applies a price cap for the form of control for metering services. The charge will be set for each year of the regulatory period, with the charges adjusted annually by CPI and an X factor. Essential Energy notes the AER has not allowed for an X factor adjustment in outer years as the X factor has been set to zero[403]. It is assumed this is due to wage and cost escalators being included in the price build-up for metering charges over the regulatory period, as some of these costs are capital and form part of the metering RAB.

Essential Energy note that an X factor has been allowed in the draft decision for ancillary network services fees, which is inconsistent with the control mechanism for metering services charges. Cost escalation has been included for these charges to ensure the correct amount is included in the metering RAB.

Revised metering charges

Attachment 9.5 to this revised proposal contains Essential Energy's revised metering model. Attachment 9.6 provides Essential Energy's PTRM for metering and Attachment 9.7 provides Essential Energy's proposed schedule of metering charges.

[401] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p43.
[402] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p43.
[403] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p48.

Ancillary Network Services

Essential Energy has proposed cost reflective charges for ancillary network services provided to specific customers, as required by the AER. These services include new services identified during the F&A process and re-classified services (from standard control) formerly known as 'Miscellaneous and Monopoly' fees.

AER draft decision

The AER draft decision approved Essential Energy's proposal for the following specified services:

- Rate based:
  - ASP Inspection L1 – UG urban
  - ASP Inspection L1 – OH rural
  - ASP Inspection L1 – UG urban C&I or rural.
- Fee based:
  - Reconnection/disconnection – out of business hours
  - Office fees – debt collection costs – dishonoured transactions
  - Office fees – ROLR services.

The AER approved Essential Energy's proposed fees for these ancillary network services, because it was considered that the underlying labour rates and overheads fell within the benchmark total labour rates developed by Marsden Jacob.

All other proposed fees have been rejected. The AER's decision to reject was based on analysis of the methodologies Essential Energy used to calculate the fees, particularly the cost inputs:

> *We reviewed Essential Energy's proposed fees for all other ancillary network services and the methodologies Essential Energy used to calculate these fees. Based on our analysis of Essential Energy's proposed methodologies we consider the main concern is the cost inputs into the methodologies. Where there are inefficiencies in actual historical costs these will be carried through in the derivation of proposed fees.* [404]

Essential Energy has not revised the proposed ancillary network services charges to adopt the AER's benchmark approach. 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 charge.
- Our overheads were calculated and applied in accordance with Essential Energy's CAM approved by the AER in May 2014.

These issues are discussed in further detail in the following sections and in Attachment 9.8.

We have reviewed our charges to ensure they reflect the latest information available and represent a cost-reflective and efficient outcome. Ancillary network services overhead rates have been updated to reflect efficiency outcomes consistent within standard control services and Essential Energy's AER approved CAM. The ancillary network services cost models are provided as Attachment 9.9 to this revised proposal. The revised fees are provided in Attachment 9.10 to this revised proposal.

[404] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p20.

Labour Costs

Essential Energy has built up charges for ancillary network services based on estimated time to complete tasks, allocated labour rates and additional material costs where appropriate.

Labour is categorised into the following categories:

- Administration R1
- Design R2a
- Inspector R2b
- Engineer R3
- Field Worker R4.

The AER have made reductions to our proposed ancillary network services fees utilising benchmarking analysis from Marsden Jacob. Whilst we acknowledge benchmarking is an available assessment tool we consider it is of limited value in forecasting practical and efficient service delivery. We do not consider the techniques are sufficiently refined enough to be relied upon to such a degree.

> *Whilst we acknowledge benchmarking is an available assessment tool we consider it is of limited value in forecasting practical and efficient service delivery.*

This application of the Marsden Jacobs analysis ignores the fact that Essential 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, Essential 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.

Base labour rates

The AER requested Marsden Jacob to provide advice on the efficiency of the labour rates and overheads applied by the businesses to determine ancillary network service charges.

> *Marsden Jacob has used professional judgement to propose a maximum rate that should be applied for each labour category based on consideration of the rates applied across the businesses and a comparison against the Hays benchmark salary rates.*[405]

Essential Energy acknowledge that Marsden Jacob has set the maximum raw labour rate at the upper quadrant of the Hays benchmark, however this analysis ignores the fact that Essential 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.

Essential Energy maintains that we 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. Essential Energy has historically used a competency based classification system to determine appropriate pay ranges for roles within the business. While there are a number of entry level positions that fall at a lower competency level, the vast majority of tasks completed within the ancillary network service space require a higher level of competency.

In line with the AER draft decision, Essential Energy has further reviewed the proposed pay ranges included within our initial proposal and compared these against the tasks provided within ancillary network services. Essential Energy accepts the Administration pay rate (R1) used was not reflective of the average of all tasks being completed; as such, Essential Energy has revised the downwards administration (R1) rate for the revised proposal. All other proposed labour rates are considered cost reflective.

[405] Marsden Jacob Associates, *Provision of advice in relation to Alternate Control Services*, 20 October 2014, p2.

The AER has generally accepted the times taken to perform services proposed by Essential Energy. We consider both our time and labour rate inputs in the revised proposal represent realistic and efficient costs of providing these services.

The AER has generally accepted the times taken to perform services proposed by Essential Energy. We consider both our time and labour rate inputs in the revised proposal represent realistic and efficient costs of providing these services.

Labour on-costs

The AER has accepted the Marsden Jacob's recommended efficient benchmark labour rates, overhead and times taken to perform services in forming their draft decision.

Marsden Jacob applied two types of on-costs to raw labour rates to complete its benchmarking:

- Basic leave entitlements including annual leave, sick leave and public holidays.
- Standard on-costs such as superannuation, workers' compensation, payroll tax, annual leave loading and long service leave.

Marsden Jacob, following a bottom up estimate, recommended that a maximum on-cost of 52.2 per cent should be applied. Essential Energy's proposed labour on-costs vary slightly from the bottom up analysis performed by Marsden Jacob; however the biggest difference comes from the application of productive hours. Essential Energy applies on-costs to worked time only, not periods of annual leave, as such on-costs are only applied to productive time. Essential Energy historical data indicates that productive time is generally around 42.6 weeks per annum (82 per cent productive time). For example, while superannuation equates to 15 per cent of employee salary, the on-cost is only applied to productive time resulting in an 18.4 per cent on-cost contribution.

Essential Energy's on-cost methodology is to only apply on-costs to productive hours, i.e. hours worked by an employee excluding leave. The result is a higher on-cost percentage than if on-costs were applied to all paid hours. Essential Energy recommends the AER retain Essential Energy's on-cost percentage to enable full cost recovery of labour related entitlements.

Essential Energy's on-cost methodology is to only apply on-costs to productive hours, i.e. hours worked by an employee excluding leave. The result is a higher on-cost percentage than if on-costs were applied to all paid hours.

Overhead allocation

Essential Energy's build up for ancillary network services charges includes both direct and indirect costs to provide a cost reflective charge for our customers. A detailed review of the AER draft determination and the Marsden Jacob report has identified some inconsistencies in overhead treatment.

Marsden Jacob calculated implied overheads to assist with benchmarking:

> *In order to benchmark overhead rates on a comparable basis, Marsden Jacob calculated an 'implied overhead rate' for each of the businesses by taking the ratio between the total labour rate proposed by the distribution business (including all on-costs and overheads) and the standard labour rate (including on-costs but not overheads).*[406]

The result of this calculation of implied overhead rates for Essential Energy is a different overhead rate for each labour category. This is inconsistent with Essential Energy's overhead allocation method; where overheads are applied on a percentage basis consistent with Essential Energy's CAM approved by the AER in May 2014. A constant overhead rate is applied to all labour categories.

[406] Marsden Jacob Associates, *Provision of advice in relation to Alternate Control Services*, 20 October 2014, p4

Essential Energy note that the AER has utilised Marsden Jacob's implied overhead rates in determining labour rates (including on-costs and overheads) to apply within the draft determination. This is inconsistent with the CAM, and results in over recovery of overheads on most labour categories.

Marsden Jacob in their analysis of overheads confirmed that Essential Energy's overheads were below the recommended benchmark. We do note however that Marsden Jacob have iterated in their report that while they have considered the overhead rates for ancillary network services in isolation, capping the overhead rate may have unintended consequences for the broader CAM. They recommended that the appropriate method of addressing the overhead allocation should be tested with the AER staff responsible for developing and enforcing the CAM[407].

Essential Energy has consistently applied indirect costs to all ancillary network services fees included within the revised proposal consistent with the CAM. We have reviewed our overhead allocation rate of 41.74 per cent and substituted a rate of 36.05 per cent (average over 5 years). This review has generally led to decreased charges for ancillary services from those submitted in our initial proposal. Further details on corporate and divisional overheads are included in Attachment 6.4 which unbundles the overheads and explains their application.

Fee inconsistencies

Essential Energy, in reviewing the AER's draft decision for Alternate Control Services and the various ancillary network services models, found a number of inconsistencies in the AER's treatment of fees proposed by Essential Energy. These include the following:

> *Essential Energy…found a number of inconsistencies in the AER's treatment of fees…*

- Draft decision charge inconsistent with model for Disconnection – Reconnection fees.
- Non-labour direct costs, such as stores and materials have been excluded from ASP fees.
- Partial approval of ASP Inspection fees, where only certain ASP inspection classes were approved despite the only difference between the fees being related to estimated labour hours.
- The fee based unit was changed from lots to poles in the draft decision for Design Certification – Underground commercial industrial or rural subdivisions.

Attachment 9.8 to this revised proposal provides further discussion on these inconsistencies. Essential Energy does not accept the AER's amendments to these fees and consider these inconsistencies should be rectified to ensure all ancillary network services charges remain cost reflective.

Network tariff change

The AER has not approved Essential Energy's proposed 'network tariff change – invalid request' charge.[408] Essential Energy notes however that a 'Network tariff change' fee was included within the AER's draft decision.[409]

Essential Energy proposed the network tariff change fee in accordance with the AER's Stage 1 F&A paper, which classified network tariff change request as an alternate control service. The AER draft decision continues to provide for inclusion of a Network tariff change request as an alternate control service:[410]

[407] Marsden Jacob Associates, *Provision of advice in relation to Alternate Control Services*, 20 October 2014, p5

[408] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, p26.

[409] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 16: Alternative control services*, November 2014, Appendix A, Table 16-25.

[410] AER, *Draft Decision - Essential Energy distribution determination 2015-16 to 2018-19 - Attachment 13: Classification of Services*, p22.

Table 9.4: Classification of network services

Service Group	Further Description	AER's draft decision on classification 2014-19	Current classification 2009-14
Network tariff change request	When a retailer's customer or retailer requests an alteration to an existing network tariff (for example, a change from an Inclining Block Tariff to a Time of Use tariff), the NSW distributors conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria. The NSW distributors also process changes in their IT systems to reflect the tariff change.	Alternate Control	Standard Control

In response to the AER's draft decision, Essential Energy has revised its definition for this service so that the fee will only apply to a valid network tariff change request outside of the annual pricing process. The network tariff change fee will not be applied where a retailer requests a tariff change that cannot be applied or where Essential Energy had incorrectly applied a tariff previously to the account.

To align with this change in definition, Essential Energy has reviewed and updated the pricing methodology to reflect the change in application of this fee. Essential Energy's revised proposal includes updated volumes and pricing for network tariff changes

Site establishment fee

In addition to this we also note that we did not submit in our initial proposal that the site establishment fee will be levied against the ASP. Whilst that is currently the method of charging, we are considering whether this approach should change. Currently, Essential Energy charges the ASP a site establishment fee and this fee is then passed onto the customer. In the past, retailers could not be charged this fee as the local retailer defaulted as the retailer for new installations. This occurred where a retailer was not nominated at the application stage; this retailer may not necessarily be the retailer once the customer moved into the premises.

An MSATS system change was implemented in May 2014, with NMIs not published to MSATS until approval by the retailer. Essential Energy proposes that as the retailer must submit an 'Allocate NMI B2B service order', the site establishment fee should be levied against the retailer subject to Essential Energy's business processes. This potential change will be considered further, including consultation with stakeholders, before a final decision is made.

10. PRICING ARRANGEMENTS AND NEGOTIATING FRAMEWORK

> Essential Energy does not accept all the AER's recommended changes to our proposal on pricing arrangements and notes numerous inconsistencies and errors of fact in the AER's determination.

Summary

The AER has made several amendments to our proposed pricing arrangements. The purpose of this chapter is to respond to the AER's draft decisions on:

- 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.
- Essential Energy's Negotiating Framework set out in AER draft decision Attachment 17.
- Essential Energy's tariff assignment methodology set out in AER draft decision Attachment 14.

Our response to the AER's draft decision

The AER has broadly endorsed Essential Energy's proposed approach to the above matters. In the sections below we provide our response to:

- Implications of the AER's proposed approach to the control mechanism for standard control services.
- The negotiating framework as provided by the AER in its draft decision.
- Proposed procedures for assigning and reassigning customers to tariff classes, including the appropriateness of providing notice to retailers of proposed tariffs assignments as opposed to communicating directly with the customer.

Application and demonstration of compliance with control mechanism and side constraint mechanism for standard control services

This section provides Essential Energy's response to the AER's draft decision on the control mechanism for Standard Control Services Attachment 14.

Broadly, Essential Energy agrees that the approach presented 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).

The following table provides a brief response to the implications of the AER's proposed approach for each element of its draft decision with regard to the control mechanism for standard control services. A more detailed repose to each of these elements and implications is provided in Attachment 10.1.

Table 10.1: Overview of Essential Energy's response to the AER's draft decision on control mechanism for standard control services

AER draft decision	Overview of Essential Energy's response
Revenue cap: Control Mechanism for Standard Control Services is revenue cap.	Essential Energy accepts this draft decision 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 AER Figure 14-1.	In principle Essential Energy accepts the formula, but will seek further consideration of some elements of the formula. Essential 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 AER Figure 14-2.	Essential Energy disagrees with the formula in AER 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 plus 2 per cent or CPI plus 2 per cent. Essential Energy has proposed an alternative formula that addresses our concerns and corrects for this error in the formula in AER Figure 14-2. Essential Energy proposes that the permissible percentage in the formula be expressed as the greater of a CPI-X plus 2 per cent or CPI plus 2 per cent. Essential Energy also notes that there is an unintended error in formula in AER Figure 14-2 where it has expressed the price change as being both less than or equal to (≤) and equal to (=).
DUOS Unders and Overs Accounts: Essential Energy must demonstrate compliance with the control mechanism for standard control services in accordance with Appendix A, of the AER's draft decision.	Essential Energy disagrees with aspects of Appendix A of the AER's draft decision which addresses the DUOS unders and overs account. Essential 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. Essential Energy request the AER use the same interest calculations as that currently in use for TUOS under and overs.
TUOS Under/ Over Recovery: Essential 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". Essential 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. Essential Energy request the AER use the same interest calculations as currently in use for TUOS under and overs.

Jurisdictional Schemes Reporting: Essential 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 Essential Energy's proposed approach, except for the inclusion of interest in year t. Essential Energy objects to the AER's draft decision not to apply interest to the opening balance in year t and request the AER use the same interest calculations as those currently in use for TUOS under and overs.
Application of Tolerance Limit	Essential Energy disagrees with the AER's approach to tolerance limits. Essential 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.

Essential Energy's Negotiating Framework and Negotiated Distribution Service Criteria

This section provides Essential Energy's response to the AER's draft decision on the Negotiating Framework Attachment 17.

We note the AER's draft decision on the negotiated distribution service criteria, however we propose minor modifications to the negotiating framework as provided by the AER in its draft decision. Essential Energy's negotiating framework for negotiated distribution services is provided in Attachment 10.2.

Procedures for assigning customers to tariff classes

This section responds to the AER's draft decision set on the procedures for assigning customers to tariff classes.

The AER rejected Essential Energy's proposed procedures for assigning customers to tariff classes on the false assumption that Essential Energy's proposed methodology will limit a retail customer's ability to seek recourse should they disagree with their tariff class assignment.

Essential 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.

Essential 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, Essential Energy maintains on its website a set of procedures detailing our processes for handling customer complaints and disputes.[411] Essential Energy is bound by and complies with these NERL dispute resolution requirements. Further, Essential Energy's customer connection agreements[412] specify our retail customer's right to dispute resolution.

The AER's claim that Essential Energy's proposed tariff assignment methodology will restrict our customer's ability to seek recourse in the event of a disagreement is not correct.

Essential Energy is concerned that the AER's proposed changes would be unduly restrictive and that the requirement to notify customers rather than their retailer is not consistent with the framework established under the NERL. We are also concerned it will lead to unworkable timeframes for finalising pricing proposals should customers or retailers seek a review of Essential Energy's proposal.

Essential Energy's detailed response to the AER's draft decision on these procedures is set out in in Attachment 10.3.

[411] Essential Energy's published procedures for customer complaints, appeals and resolution can be found in Attachment 10.2.
[412] *Essential Energy Deemed Standard Connection Contracts*, Section 16 and *Essential Energy Deemed Standard Connection Contract for Large Customers*, Section 17.

ATTACHMENTS TO THE REVISED PROPOSAL

Attachment number	Attachment name
1.1	Chief Operating Officer Statement, Partially confidential
1.2	Asset/System Failure Safety Risk Assessment – R2A
1.3	Insurance Advice Report – AON, Partially confidential
1.4	System Capex and Maintenance Prudency Assessment – Jacobs
1.5	Reliability Impact Assessment – Jacobs
1.6	Economic Regulation - David Newbery
1.7	Credit Assessment – S&P, Confidential
1.7a	Ratings Definitions – S&P, Confidential
17.b	Stand Alone Credit Profile – S&P, Confidential
1.8	Financial Sustainability – UBS, Partially confidential
1.9	Potential AER impacts
3.1	Willingness to Pay for Network Services – IPSOS Research
3.2	Stakeholder Engagement Framework
3.3	How Consumer Engagement Informed Our Revised Proposal
4.1	Classification Proposal
4.2	Application of STPIS
5.1	Roll Forward Model
5.2	Accounting for Provisions - EY
5.3	Review of Standard and Remaining Lives of Assets – Advisian
5.4	EBSS carryover amount calculation
5.5	Post Tax Revenue Model

Attachment number	Attachment name
5.6	Electrical energy and customer number projections for Essential Energy in New South Wales to 2024-25 – NIEIR
5.7	Pass Through Events
6.1	Connection Policy
6.2	Capital Governance
6.3	Appropriateness of RIN data for benchmarking – PWC
6.4	Operating Expenditure Corporate Overhead and Divisional (Network) Overhead
6.5	AER Approved Cost Allocation Method
6.6	Replacement Expenditure
6.7	Augmentation Expenditure
6.8	Network aerial patrol and analysis (AP&A) – Step Change Analysis
6.9	Technical response to the application of benchmarking by the AER - Huegin
6.10	Risk based prioritisation process for Networks NSW - post implementation review – Advisian
6.11	Deliverability
6.12	Cost Escalation factors report – CEG
6.13	Cost Escalation factors update – Independent Economics
6.14	Cost Escalation Model
6.15	Group Executive Network Strategy Statement, Partially confidential
7.1	Review of the AER's econometric benchmarking models – Frontier
7.2	Review of AER Benchmarking – Advisian
7.3	Benchmarking Review - Pacific Economics Group
7.4	Operating Expenditure
7.5	Response to Deloitte Access Economics report on NSW DNSP Labour Analysis, Confidential

Attachment number	Attachment name
7.6	Productivity, Partially condidential
7.7	Labour unit cost - review of Deloitte report – CEG, Confidential
7.8	Comparison and Analysis of Enterprise Bargaining Agreements for Distribution Networks - K&L Gates, Confidential
7.9	Transformation in the Electricity Distribution Network Industry
7.10	Vegetation Management
7.11	Asset Growth Escalator
8.1	Efficient Debt Financing Costs – CEG
8.2	Estimating the Cost of Equity - CEG
8.3	Cost of Debt Transition for NSW Distribution Networks – Frontier Economics
8.4	Report on the cost of equity for ActewAGL and the NSW DNSPs - SFG
8.5	Letter from Bruce Grundy to Justin De Lorenzo
8.6	NERA memo on revised MRP estimates to 2013
8.7	AOFM Letter from Michael Bath
8.8	Group Chief Financial Officer Statement, Confidential
8.9	Essential Energy's Revised Proposal on Gamma
9.1	Public Lighting
9.2	Public Lighting Models
9.3	Charges for Public Lighting
9.4	Type 5 and 6 Metering Services
9.5	Type 5 and 6 Metering Services Model
9.6	Type 5 and 6 Metering Services PTRM
9.7	Charges for Type 5 and 6 Metering Services

Attachment number	Attachment name
9.8	Ancillary Network Services Proposal
9.9	Ancillary Network Services Models
9.10	Charges for Ancillary Network Services
10.1	Control Mechanism for Standard Control Services
10.2	Negotiating Framework Negotiated Distribution Services
10.3	Revised Tariff Assignment Methodology

GLOSSARY

Term	Definition
($ nominal) [for paragraphs]	$XXXXX million ($ nominal) This is the dollar of the day
($ million) [for Tables]	Nominal dollars for Table/Figure captions e.g. Opening RAB ($ million, nominal)
(2013 – 14 dollars)	$XXXXX ($2013-14) Real dollars. This denotes the dollar terms as at 30 June 2014
($ million, 2013-14) [for Tables]	Real dollars for Table/Figure captions e.g. Table 5-5 – Forecast capital expenditure ($ million, 2013-14)
2009-14 regulatory period	The regulatory control period commencing 1 July 2009 and ending 30 June 2014
2014-19 regulatory period	The period comprising bot the transitional regulatory control period 1 July 2014 to 30 June 2015 and the 2015-19 regulatory period
2015-19 regulatory period	The regulatory control period commencing 1 July 2015 and ending 30 June 2019
2019-24 regulatory period	The regulatory control period commencing 1 July 2019 and ending 30 June 2024
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMP	Asset management plan
AMS	Asset management system
AOFM	Australian Office of Financial Management
AP&A	Aerial Patrol & Analysis
ARR	Annual revenue requirement
ASP	Accredited Service Provider

Term	Definition
ATO	Australian Tax Office
Augex	AER’s augmentation expenditure model
C&I	Commercial and Industrial
CALD	Culturally and Linguistically Diverse
CAM	Cost allocation method
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CASH	Capital Allocation Selection Hierarchy
CEG	Competition Economics Group
CCF	Climate Change Fund
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
COAG	Council of Australian Governments
CPI	Consumer Price Index
CRNP	Cost Reflective Network Price
DAPR	Distribution Annual Planning Report
DGM	Dividend Growth Method
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
DUOS	Distribution Use of System

Term	Definition
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
ESV	Energy Safe Victoria
F&A	Framework and approach paper
FMECA	Failure modes effects criticality analysis
GFC	Global Financial Crisis
GGF	Government Guarantee Fee
HIP	Home Insulation Program
HoC	Hierarchy of Controls
HV	High Voltage
IPART	Independent Pricing and Regulatory Tribunal of NSW
IT	Information Technology
LiDAR	Light Detection and Ranging
LV	Low Voltage
MEC	Major Electricity Companies
MRIM	Manually Read Interval Meter
MRP	Market Risk Premium
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Electricity Retail Law

Term	Definition
NMI	National Metering Identifier
NNSW	Networks NSW
NSW	New South Wales
NUOS	Network Use Of System
Opex	Operating expenditure
PCBU	Person conducting a business or undertaking
PIP	Portfolio Investment Plan
PIAC	Public Interest Advocacy Centre
PTRM	Post Tax Revenue Model
QLD	Queensland
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RCM	Reliability Centred Maintenance
Regulatory proposal	Essential Energy's regulatory proposal for the 2014-19 regulatory control period submitted under clause 6.8 of the NER
Repex	AER's replacement expenditure model
RIN	Regulatory Information Notice
RFM	Roll Forward Model
ROC	Regional Organisation of Council's
ROLR	Retailer of Last Resort
Rules	National Electricity Rules
S&P	Standard and Poors
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

Term	Definition
SCC	Streetlighting Consultative Committee
SCS	Standard control services
SFA	Stochastic frontier analysis
SFAIRP	So far is as reasonably practicable
STPIS	Service Target Performance Incentive Scheme
Subsequent regulatory period	Regulatory control period 1 July 2015 to 30 June 2019
TCorp	NSW Treasury Corporation
Transitional NER	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 year
Transitional regulatory period	Regulatory control period 1 July 2014 to 30 June 2015
Transitional regulatory proposal	Regulatory proposal prepared in accordance with the transitional NER
Transitional year	The transitional regulatory period 1 July 2014 to 30 June 2015
TSA	Transitional Services Agreement
TUOS	Transmission Use of System
VBRC	Victorian Bushfire Royal Commission
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WHS Act	Workplace Health and Safety Act 2011 (NSW)

