FINAL DECISION
Endeavour Energy distribution determination
2015–16 to 2018–19

Overview

April 2015

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

AER reference: 52294

Note

This overview forms part of the AER's final decision on Endeavour Energy's distribution determination for 2015–19. It should be read with other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – annual revenue requirement

Attachment 2 – regulatory asset base

Attachment 3 – rate of return

Attachment 4 – value of imputation credits

Attachment 5 – regulatory depreciation

Attachment 6 – capital expenditure

Attachment 7 – operating expenditure

Attachment 8 – corporate income tax

Attachment 9 – efficiency benefit sharing scheme

Attachment 10 – capital expenditure sharing scheme

Attachment 11 – service target performance incentive scheme

Attachment 12 – demand management incentive scheme

Attachment 13 – classification of services

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model

Shortened form	Extended form
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Our final decision

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission and distribution systems in all states and territories except Western Australian and the Northern Territory. Endeavour Energy is one of three distribution network service providers (distributors) in NSW and is responsible for providing electricity distribution services in Sydney's Greater West, the Blue Mountains, Southern Highlands, Illawarra and South Coast of NSW. We regulate the revenues Endeavour Energy and the other distributors can recover from their customers.

The National Electricity Law (NEL) and National Electricity Rules (NER) provide the regulatory framework under which we operate. Most relevantly, they set out how we must assess a regulatory proposal and make our decision.

The National Electricity Objective (NEO) sits at the centre of the NEL and NER. The NEO 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—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[1]

Under the NER, Endeavour Energy must submit a regulatory proposal to us for approval.[2] The central component of a regulatory proposal is the amount of revenue Endeavour Energy proposes to recover from consumers over the 2015-19 regulatory control period.[3] We must assess Endeavour Energy's proposal, using the NER's detailed rules. The NER addresses a range of constituent components of a revenue proposal. We must decide whether to accept Endeavour Energy's proposal. If we do not accept that Endeavour Energy's proposal complies with the NER's requirements, we must substitute an alternative amount of revenue that we are satisfied does comply. We must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NEO and, where appropriate, contribute to the greatest degree.

We regulate Endeavour Energy's revenue, not its costs. Endeavour Energy must decide how best to use this revenue in providing distribution services and fulfilling its obligations. This provides incentives for distributors, such as Endeavour Energy, to operate their businesses efficiently and, in the long run, at least cost to consumers. It

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1 NEL, s. 7.

2 NER, cl. 6.8.2.

3 NER, cll. 6.3.1 and 6.8.2. As we explained in our draft decision, the regulatory control period is 2015-19. However, the NER requires us to determine a notional annual revenue requirement for each year of the 2014-19 period. We must then true this us with the placeholder 2014-15 annual revenue requirement we determined in the placeholder decision we made in 2014. As a result, this decision often refers to the 2014-19 period, rather than the 2015-19 regulatory control period.

also provides incentives for distributors to innovate and invest in response to changes in consumer needs and productive opportunities.[4] This is consistent with economic efficiency principles. It also means that the person who is best able to manage a risk, generally carries that risk.

Endeavour Energy submitted its regulatory proposal in May 2014. In November 2014 we made a draft decision and, in January 2015, Endeavour Energy submitted a revised proposal. We also received submissions from various stakeholders on Endeavour Energy's initial and revised proposal as well as our draft decision.

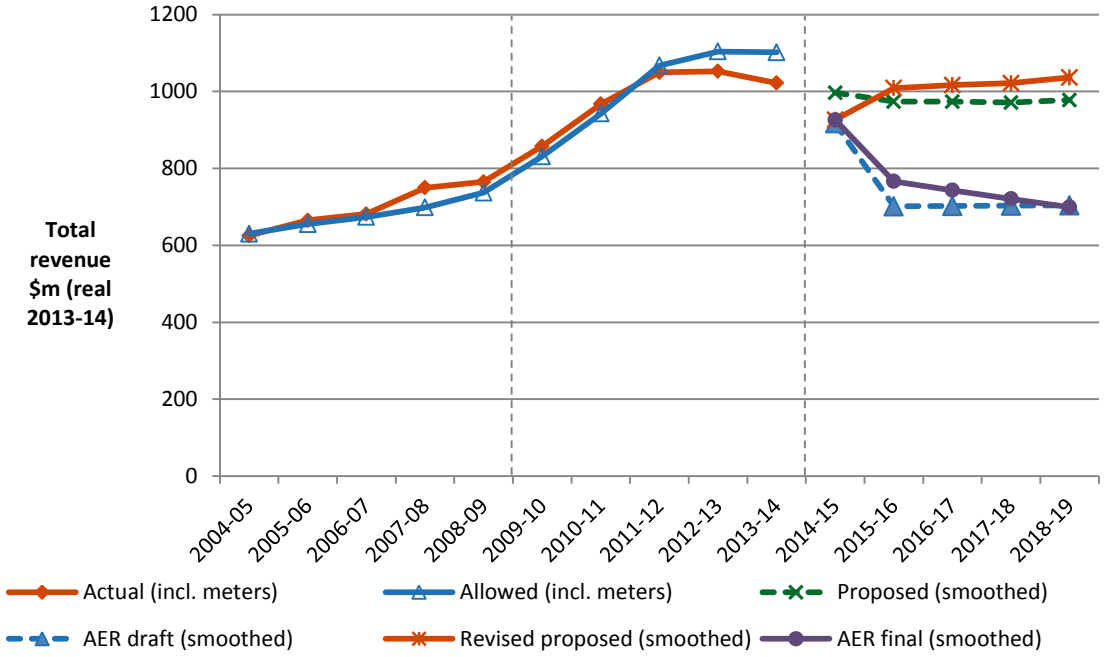
This overview, together with its attachments, constitutes our final decision on Endeavour Energy's revised proposal. The overview provides a summary of our decision, including all the constituent components that make up our final decision. It sets out the issues we covered, the conclusions we made, and how those conclusions were reached. We also explain why we are satisfied our decision contributes to the achievement of the NEO to the greatest degree and why we do not consider that Endeavour Energy's revised proposal contributes to the achievement of the NEO to a satisfactory degree. In our attachments we set out detailed analysis of the constituent components that make up Endeavour Energy's revised proposal and our decision on each of them. There is a full list of the constituent components of this decision in appendix A.

1.1 Decision

Our final decision is that Endeavour Energy can recover $3182.8 million ($ nominal) from consumers over the 2015–19 regulatory control period. Figure 1 below illustrates our overall decision.

[4] Hansard, SA House of Assembly, 9 February 2005 p. 1452

Figure 1 Endeavour Energy's past total revenue, proposed total revenue and AER total revenue allowance ($ million, 2013–14)



Source: AER analysis.

Distribution charges represent approximately 39 per cent, on average, of the annual electricity bill for Endeavour Energy customers.[5] If the lower distribution charges flowing from our decision are passed through to customers, we would expect the average annual electricity bill for residential and small business customers to reduce in the 2015–19 regulatory control period. However, other factors also affect a customer's electricity bill, such as the wholesale price of electricity.

Table 1 shows the estimated impact of our final decision on the average residential and small business customers' annual electricity bills in Endeavour Energy's network area over the 2014–19 period, compared with what was proposed.

Table 1 AER's estimated impact of the final decision on the average residential and small business customers' electricity bills in Endeavour Energy's network for the 2014–19 period ($ nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Endeavour Energy revised proposal						
Residential annual bill[a]	2026	1978	2075	2091	2108	2126
Annual change		–48 (–2.3%)	96 (4.9%)	17 (0.8%)	17 (0.8%)	17 (0.8%)

[5] Endeavour Energy, *Regulatory proposal*, June 2014, p. 1.

Small business annual bill[b]	2909	2841	2979	3003	3027	3052
Annual change		–68 (–2.3%)	138 (4.9%)	24 (0.8%)	24 (0.8%)	25 (0.8%)
AER final decision						
Residential annual bill[a]	2026	1978	1873	1861	1852	1836
Annual change		–48 (–2.3%)	–106 (–5.3%)	–12 (–0.6%)	–10 (–0.5%)	–15 (–0.8%)
Small business annual bill[b]	2909	2841	2689	2672	2659	2636
Annual change		–68 (–2.3%)	–152 (–5.3%)	–17 (–0.6%)	–14 (–0.5%)	–22 (–0.8%)

Source: AER analysis; AER, Energy Made Easy; IPART, *Final report: Review of regulated retail prices for electricity - from 1 July 2013 to 30 June 2016*, June 2013, p. 5.

(a) Based on annual charge for typical consumption of 6500KWh per year during the period 1 July 2013 to 30 June 2014. The charges reflect regulated price only. Sample postcode: 2500.

(b) Based on the annual charge sourced from Energy Made Easy for a typical consumption of 10000 kWh per year during the period 1 July 2013 to 30 June 2014. The charges reflect regulated price only. Sample postcode: 2500.

1.2 Contribution to the achievement of the NEO

We are satisfied that the total revenue approved in our final decision contributes to the achievement of the NEO to the greatest degree. This is because our total revenue reflects the efficient, sustainable costs of providing network services in Endeavour Energy's operating environment and the key drivers of efficient costs facing Endeavour Energy. Our decision will promote the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers, as required by the NEO. We set out our reasons below and in our attachments.

The key drivers of costs facing a network service provider are:[6]

- its accumulated network investment (reflected in the size of its Regulatory Asset Base, or RAB)
- its expected growth in network investment (reflected in its capital expenditure (capex) program net of capital returned to the shareholders through depreciation)
- its financing costs (interest on borrowings and a return on equity to shareholders) and
- its operating expenditure (opex) program (the cost of operating and maintaining its network)
- its taxation cost (taxable income at the corporate tax rate adjusted for the value of imputation credits).

[6] How these key cost drivers impact total revenue is further explained in section 2 of this Overview.

From one regulatory period to the next, the pressures on each of these drivers may change. For example, in periods of high demand growth, a network service provider would expect to need a larger capex program. Similarly, during periods of high interest rates, a network service provider would expect to pay more in financing costs.

The most important factors we see impacting on Endeavour Energy's costs in the 2015–19 regulatory control period include:

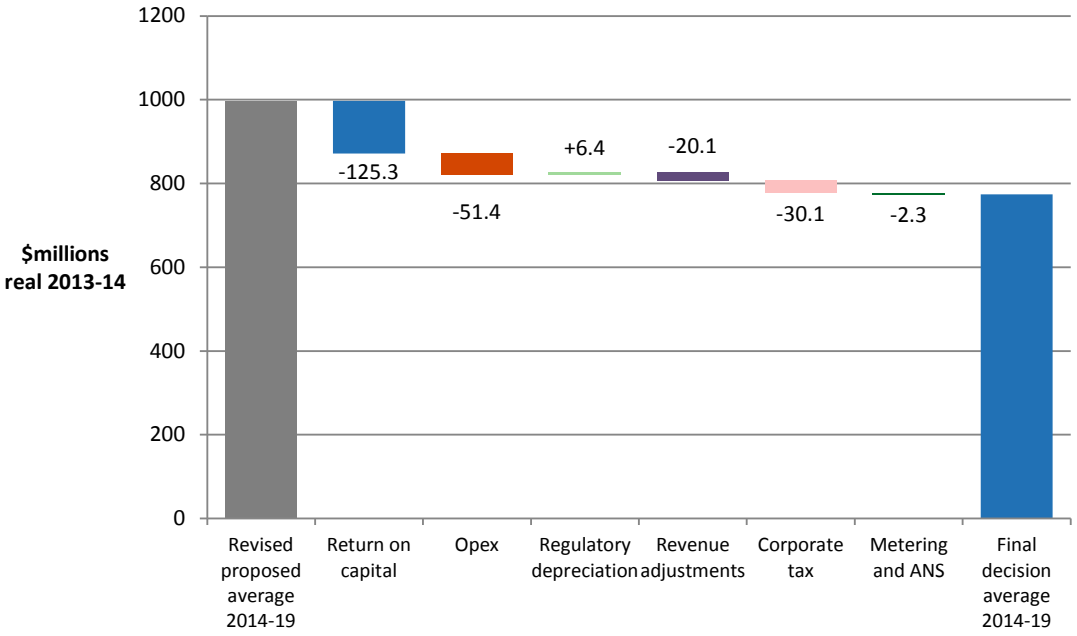
- an improved investment environment compared to our 2009 decision, which translates to lower financing costs necessary to attract efficient investment.
- lower than expected demand growth in the previous regulatory period, which has led to falling levels of network utilisation across Endeavour Energy's network.
- forecast demand, which is expected to remain reasonably flat over the 2015–19 regulatory control period. This means that Endeavour Energy is under less pressure to expand its network than in the previous regulatory control period to meet the needs of additional customers or any increased demand from existing customers.

These factors are reflected throughout our final decision and impact the different constituent components of our decision to varying degrees. At the total revenue level, they provide a consistent picture: Endeavour Energy, operating prudently and efficiently, could provide distribution services with materially less revenue than it has proposed for the 2015–19 regulatory control period. Further, the average annual revenue Endeavour Energy requires in the 2015–19 regulatory control period is materially less than the revenue it recovered from customers in the previous regulatory control period.

In our final decision we consider that Endeavour Energy's proposal does not reflect the factors impacting on its cost drivers to a satisfactory extent. As a consequence, we conclude that Endeavour Energy has proposed to recover more revenue from its customers than is necessary for the safe and reliable operation of its network. It follows that we consider that Endeavour Energy's revised proposal does not contribute to the achievement of the NEO to a satisfactory degree.

Two constituent components of our decision drive most of the difference between Endeavour Energy's proposed revenue and our final decision: rate of return and opex. We discuss these further below. Figure 2 illustrates the key differences (in terms of constituent components, or building blocks, making up total revenue) between our decision and Endeavour Energy's revised proposal.

Figure 2 AER's final decision and Endeavour Energy's revised proposed annual building block costs ($ million 2013–14)



Source: AER analysis.

1.2.1 Rate of return

The rate of return provides a service provider with revenue to service the interest on its loans and to give a return on equity to shareholders. The allowed rate of return is a key determinant of allowed revenue.

The rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.[7] The NER refers to this requirement as the allowed rate of return objective.

Our final decision is for a rate of return of 6.74 per cent (for 2014–15) compared to 8.85 per cent put forward by Endeavour Energy in its revised proposal.[8] The rate of return for 2015–16 will be 6.68 per cent. For the rest of the regulatory control period, we will update the rate of return annually.

We set out our approach to determining the rate of return in the Rate of Return Guideline (Guideline) we published in December 2013.[9] This Guideline is not binding.

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7 NER, cl. 6.5.2(b)

8 The rate of return that Endeavour Energy included in its proposal is an indicative value. Its proposal includes provision for the AER to adjust this value based on updated information that was not available when Endeavour Energy submitted its revised proposal.

9 AER, Rate of Return Guideline, December 2013: http://www.aer.gov.au/node/18859

However, a distributor must provide reasons to justify any departure from the Guideline. Endeavour Energy has proposed we depart from the Guideline. We disagree.

Prevailing market conditions for debt and equity heavily influence the rate of return. In our draft decision we pointed out that financial conditions have improved markedly since our 2009 final decision, resulting in a lower rate of return. Since our draft decision, interest rates have fallen further and financial market conditions have continued to ease. This means that the cost of debt and the returns required to attract equity are lower than when we made our draft decision. We consider these factors should be reflected in the final rate of return.

On a more technical level, there are two key differences between our final decision and Endeavour Energy's revised proposal in relation to rate of return:

- whether to use a forwards or backwards looking approach in transitioning between approaches to setting our estimate of the return on debt
- whether to give weight to other indicators of the return on equity that Endeavour Energy considers to be informative but which we do not consider to be robust and which other regulators do not use.

The Guideline (and indeed, this decision) marks a departure from our previous approach to estimating the return on debt and the return on equity. For the return on debt, we have used a gradual, forward looking transition to do so. We set out this transition in the Guideline. Our approach to setting the return on debt received broad support across many stakeholders, including some service providers.[10] The evidence Endeavour Energy provided does not convince us that we should depart from the approach in our Guideline, for this final decision.[11] For the return on equity, the expert evidence before us indicates that on balance employing our approach is expected to lead to a rate of return that achieves the allowed rate of return objective.

1.2.2 Operating Expenditure

Opex is required to operate and maintain the distributor's network. Like rate of return, it is a key driver of total revenue.

Our final decision is for a forecast opex amount of $1.22 billion ($2013–14) compared to $1.47 billion ($2013–14) put forward by Endeavour Energy in its revised proposal. This reflects a 16.9 per cent reduction.

Whether we should use historical costs as the starting point for forecasting its future costs is a key issue in determining a distributor's opex forecast. In contrast to Ausgrid and Essential Energy, we consider that we are able to rely on Endeavour Energy's

[10] For example, TasNetworks, Regulatory Proposal, June 2014

[11] See Attachment 3 - Rate of Return

revealed expenditure as the starting point for determining our estimate of Endeavour Energy's efficient total forecast opex. This is explained further in attachment 7.

Under the NER, a distributor's proposal must include the total forecast operating expenditure which the distributor considers is required in order to achieve each of the following (opex) objectives:

- meet or manage expected demand
- comply with certain obligations and service standards
- maintain the safety of the distribution system.[12]

For Endeavour Energy, the key issue driving the difference between our final decision and Endeavour Energy's revised forecast opex is our decision not to include a step change for increased vegetation management costs.

Endeavour Energy's proposed increase in opex relates to compliance with its existing regulatory obligations. We are satisfied Endeavour Energy's revealed opex is sufficient for it to meet all of its existing regulatory obligations including for vegetation management. We did not consider there was sufficient evidence to support a material increase above Endeavour Energy's revealed expenditure.

1.3 Key issues raised in revised proposal

In its revised proposal, Endeavour Energy raised some overarching concerns it had with our draft determination, including:

- safety implications of our draft decision
- use of benchmarking in setting revenue allowances
- consumer engagement
- financeability.

We have considered Endeavour Energy's views on these issues in detail in the relevant attachments. However, we consider these issues are sufficiently important that we also address them briefly here.

1.3.1 Safety and reliability

Endeavour Energy argued that our draft decision would not provide sufficient revenue for the company to operate its system safely and reliably. We have considered Endeavour Energy's and other stakeholders' submissions. This final decision approves a revenue allowance that will fund the *efficient* costs that Endeavour Energy acting as a prudent operator would require to run the system safely and reliably. To the extent that Endeavour Energy incurs costs that are above efficient levels they should be borne by Endeavour Energy's shareholders and not its consumers.

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[12] NER, cll 6.5.6(a)

We have considered safety, reliability and security in a number of ways:

- our consultant has reviewed Endeavour Energy's risk and governance practices
- we have considered operating environment factors, such as network conditions and other regulatory obligations, that may impact safety, reliability and security
- we have considered the reliability and security of the network when considering individual aspects of the proposal, such as step changes and expenditure on bushfire mitigation projects
- our benchmarking analysis accounts for safety, reliability and security, so that our substitute opex allowance represents the efficient costs that a prudent operator would require to run the system at the existing level of safety and reliability we have allowed all the capex that Endeavour Energy sought that is associated with safety, reliability and security issues
- the Service Target Performance Incentive Scheme (STPIS) provides incentives to distributors to efficiently maintain and improve service performance..

After making these inquiries, we conclude that Endeavour Energy's distribution services should be provided at substantially lower cost while still maintaining safety and complying with reliability obligations.

1.3.2 Use of benchmarking

Endeavour Energy rejected the way we applied benchmarking in the draft decision. Endeavour Energy suggested that our benchmarking data was untested and unreliable, and should not play a role in the final determinations.

We have considered Endeavour Energy's submissions and the submissions made by other stakeholders about our benchmarking models and data. We have confidence in the data that we used in our benchmarking models as it was developed in conjunction with industry it has been subject to extensive review and testing. We note that benchmarking is a well-developed technique used extensively by regulators in many other jurisdictions. Supported by the views of our benchmarking expert, we consider our models are the best available for measuring the efficiency of the service providers. Our benchmarking model was carefully chosen after considering the results of previous work, the models used by regulators in overseas jurisdictions and the main cost drivers of electricity distribution businesses. We have adopted a benchmark comparison point which has a lower efficiency score than the frontier service provider. The benchmark comparison point for our final decision is AusNet Services.

This approach is consistent with our Expenditure Forecast Assessment Guideline, which established a materiality threshold for making adjustments to base opex.

While we consider that Endeavour Energy's revealed opex still includes inefficiencies, we have determined that they are not materially inefficient for the purposes of developing an alternative forecast that we are satisfied reasonably reflects the opex criteria. On this basis our final decision is to rely on Endeavour Energy's revealed opex as a starting point for forecasting its future opex.

1.3.3 Consumer engagement

Endeavour Energy considers we discounted evidence relating to consumer and stakeholder preferences.[13] In support of its revised proposal, Networks NSW on behalf of Ausgrid, Endeavour Energy and Essential Energy commissioned further work by Ipsos into consumer preferences and submitted a report on the preliminary findings of this research.[14] Based on the findings of the research, Endeavour Energy concluded 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."

We considered the report provided by Endeavour Energy and the supporting material provided in response to our information requests. The findings of the research were based on the assumption that our draft decision would require the NSW distributors to reduce safety, service and reliability levels. We do not agree with this assumption and as such give little weight to the research's findings in our final decision. In our view, each of the NSW distributors can maintain their levels of efficiency and provide safety, service and reliability at lower cost to consumers.

We commissioned Oakley Greenwood to peer review the willingness to pay research conducted by Ipsos. Oakley Greenwood also commented on the key assumption underpinning the research, that being that Endeavour Energy's assertion that 'the cuts proposed by the AER will reduce reliability'. Oakley Greenwood pointed out in its report that this assumption 'may have limited the scope as compared to what might have been a fuller treatment of consumers' preferences'.[15] In other words, research findings are sensitive to the assumptions used.

In commenting on the conclusions that can be drawn from the Ipsos research, Oakley Greenwood identified that many customers appear to have misperceived the level of service they were currently receiving.[16] Oakley Greenwood concluded that:

> "…the statement that 'the majority [of customers] are not willing to trade reliability, safety and service for lower charges' is an oversimplification of the survey results."[17]

We find Oakley Greenwood's conclusions compelling. While willingness to pay research is useful in certain circumstances, it is highly sensitive to the assumptions

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13 Endeavour Energy, Revised Regulatory Proposal, January 2015, p. 10

14 Endeavour Energy, Revised Regulatory Proposal, January 2015, Attachment 2.11.

15 Oakley Greenwood, Peer review of the willingness to pay research submitted by NSW distribution business, April 2015, p. 4

16 Oakley Greenwood, Peer review of the willingness to pay research submitted by NSW distribution business, April 2015, p. 11

17 Endeavour Energy, Revised Regulatory Proposal, January 2015, p. 10.

used and consumer understanding of those assumptions. The willingness to pay research commissioned by Networks NSW does provide useful insights. However, the willingness of customers to make trade-offs is likely to be more complex than the binary conclusions reached by the NSW distribution businesses.[18]

We consider that the primary purpose of consumer engagement is for consumers to have a meaningful opportunity to engage in Endeavour Energy's processes. In particular, we consider that consumers should be provided with the opportunity to help shape Endeavour Energy's proposal and the services it offers. Our view is that Endeavour Energy has not provided consumers with sufficient opportunity to influence its processes.

1.3.4 Financeability

In its revised proposal, Endeavour Energy indicated that its financial viability would be threatened as a result of our draft decision. In support of this, Endeavour Energy submitted a range of material including:

- an expert's report from David Newbery submitting that sizeable opex reductions in a short period of time would negatively impact the ongoing financeability of the DNSPs and their viability as economic entities[19]
- a confidential credit profile report by Standard and Poors (S&P)[20]
- A report by UBS including confidential content relevant to financeability[21]

Neither the NEL nor the NER include an explicit obligation requiring us to consider the impact of our determination on the viability of the service provider in its actual circumstances. Our task is to determine the revenue that a service provider can recover from its customers with reference to an efficient and prudent level of expenditure. The service provider's actual ownership circumstances and the financial structure of its shareholders are not factors that we are required to consider in fulfilling our task under the NEL or the NER.

We are satisfied that a revenue allowance that meets the requirements of the rules will provide for Endeavour Energy, acting as a prudent operator with efficient costs, using a realistic expectation of demand and cost inputs, with the revenue it requires to operate viably. However, to the extent that a service provider departs from such expenditure levels, it may be at greater financial risk. Since Endeavour Energy raised this issue as a concern, we have considered it and the material put forward in support of its concerns. Endeavour Energy has not been clear about what it means by the term financial viability. In our analysis we have considered whether Endeavour Energy

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18 Oakley Greenwood, Peer review of the willingness to pay research submitted by NSW distribution business, April 2015, p. 12

19 David Newbery, *Cambridge Economic Policy Associates: Expert Report*, January 2015.

20 S&P, *Confidential credit assessment: Endeavour Energy—Stand-alone credit profile*, January 2015.

21 UBS, *Financeability— Debt issue and capital structure (Confidential version)*, January 2015

would be at material risk of insolvency. We understand this to be consistent with Endeavour Energy's interpretation of threats to its financial viability. We undertook analysis using our PTRM to model Endeavour Energy's cash flows under a number of different scenarios. We then engaged RSM Bird Cameron to review and provide comment on our analysis. We are satisfied that Endeavour Energy would not be at material risk of insolvency because:

- Endeavour Energy is subject to a stable regulatory environment that is favourable for capital raising[22]
- we are not persuaded that the assumptions Endeavour Energy provided to S&P were reasonable. The conclusions in the stand-alone credit profile prepared by S&P derive from the assumptions provided by Endeavour Energy.
- we are satisfied that our PTRM cash flow analysis and RSM Bird Cameron's review and comment on our analysis supports this conclusion.

RSM Bird Cameron's report is attached to this decision. We discuss this report in greater detail in attachment 20.

1.4 Assessment of options under the NEO

The NER recognises that there may be several decisions that contribute to the achievement of the NEO. Our role is to make a decision that we are satisfied contributes to the achievement of the NEO to the *greatest* degree.[23]

For at least two reasons, we consider that there will almost always be several decisions that contribute to the achievement of the NEO. First, the NER requires us to make forecasts, which are predictions about unknown future circumstances. As a result, there will likely always be more than one plausible forecast. Second, there is substantial debate amongst stakeholders about the costs we must forecast, with both sides often supported by expert opinion. As a result, for several components of our decision there may be several plausible answers or several point estimates within a range. This has the potential to create a multitude of potential overall decisions. In this decision we have approached this from a practical perspective, accepting that it is not possible to consider every possible permutation specifically. Where there are several plausible answers, we have selected what we are satisfied is the best outcome, under the NEL and NER.

In many cases, our approach results in an outcome towards the end of the range of options materially favourable to Endeavour Energy (for example, our choice of equity beta). While it can be difficult to quantify the exact revenue impact of these individual

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[22] For example, RARE infrastructure submitted that "[t]here are many characteristics of the Australian Regulatory framework that makes its energy network potentially attractive investments" RARE Infrastructure, *Letter to the AER*, 13 February 2015.

[23] NEL, s. 16(1)(d)

decisions, we have identified where we have done so in our attachments. Some of these decisions include:

- selecting at the top of the range for the equity beta
- setting the return on debt by reference to data for a BBB broad band credit rating, when the benchmark is BBB+
- the cash flow timing assumptions in the post-tax revenue model
- the point at which we have set the benchmark for opex
- the allowances we have made for operating environment factors in our benchmarking analysis

We set out detailed our reasons in the attachments. They demonstrate that the constituent components of our decision comply with the NER's requirements. At an overall level our decision reflects the key reasons set out above, which indicate that Endeavour Energy should recover less revenue than it has proposed or recovered in recent years. Our decision reflects these at both the constituent component and overall revenue levels.

Given our approach, we are satisfied that our decision will or is likely to contribute to the achievement of the NEO to the greatest degree.

1.5 Structure of the overview

The remainder of this overview discusses the overarching issues in this decision, including those above, in more detail. It is structured as follows:

- Section 2 sets out the key constituent components making up our final decision
- Section 3 sets out our decision on the classification of services, control mechanisms and incentive schemes
- Section 4 explains our views on the regulatory framework
- Section 5 outlines the process we undertook in reaching our final decision

2 Key elements of the building blocks

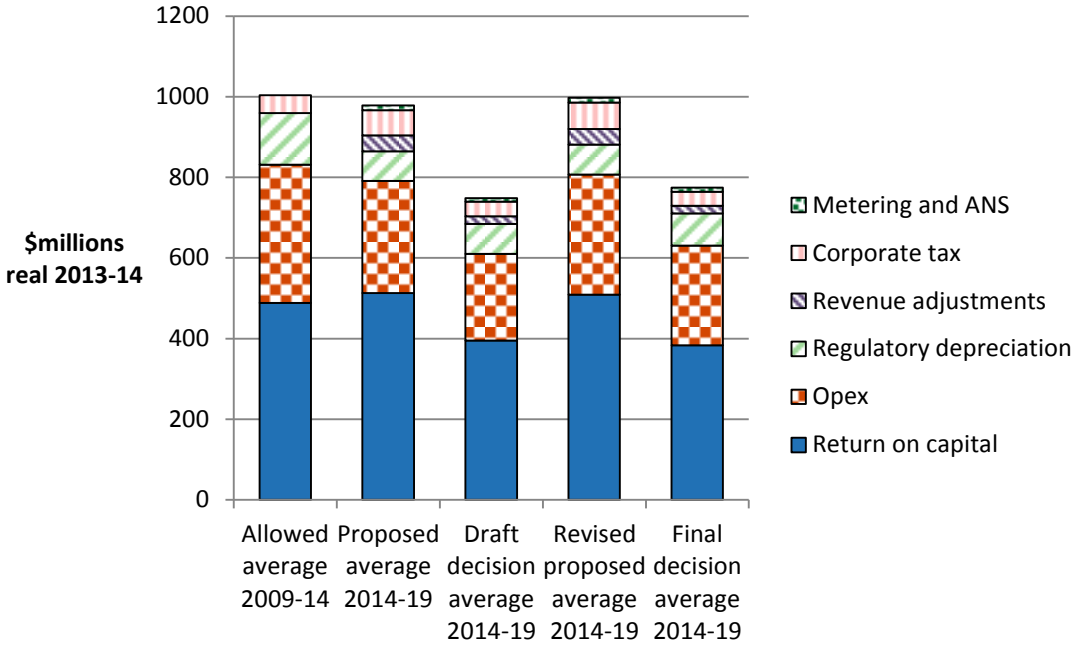
The constituent components of our decision include the building blocks we use to determine the revenue Endeavour Energy may recover from its customers.[24]

In setting our allowed revenue for Endeavour Energy of $3182.8 million ($ nominal) for the 2015–19 regulatory control period we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation guidelines[25] (see section 5.1). We also consider information provided by Endeavour Energy, the Consumer Challenge Panel (CCP), consultants and stakeholder submissions
- consider our overall revenue against section 16 of the NEL, including the constituent decisions and the interrelationships we discussed in sections 1 and 4.

Figure 3 and Table 2 show our final decision on Endeavour Energy's revenues and the contribution of each building block.

Figure 3 AER's final decision and Endeavour Energy's proposed annual building block ($ million, 2013–14)



Source: AER analysis.

[24] NER cl.6.3.

[25] http://www.aer.gov.au/Better-regulation

Table 2 AER's final decision on Endeavour Energy's revenues ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	376.4	397.1	415.7	430.4	444.8	2064.4
Regulatory depreciation	69.3	78.9	89.7	93.8	100.0	431.7
Operating expenditure	244.3	254.1	264.4	275.3	287.3	1325.4
Revenue adjustments[a]	81.8	13.2	27.4	-24.4	0.7	98.7
Corporate tax allowance	36.2	34.7	38.7	38.3	39.5	187.4
Meters, ANS costs[b]	50.5[b]	n/a	n/a	n/a	n/a	50.5
Annual revenue requirement (unsmoothed)	858.6	778.0	835.9	813.4	872.2	4158.2
Annual expected revenue (smoothed)	**949.5**	**804.0**	**798.5**	**792.9**	**787.5**	**4132.3**
X factor[c]	n/a[d]	17.29%	3.00%	3.00%	3.00%	n/a

Source: AER analysis.

(a) Revenue adjustments include efficiency benefit sharing scheme carry-overs and forecast DMIA.

(b) These are the efficient total costs of metering and ancillary network services as determined by the AER. In the draft decision we included only the net costs of ACS (that is, the total ACS costs less revenues of $9.6 million recovered through separate charges for 2014–15). For the final decision we included the total ACS costs consistent with Endeavour Energy's revised proposal.

(c) The X factor from 2016–17 to 2018–19 will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(d) In our transitional decision, we determined the placeholder revenue for 2014–15. In this final decision to update the 2014–15 revenue for our assessment of efficient costs we determined X factors for the final four years of the 2014–19 period. This is to adjust Endeavour Energy's total revenue requirement for the 2015–19 regulatory control period for the difference between the placeholder revenue and our decision on Endeavour Energy's efficient costs for 2014–15.

2.1 The building block approach

We have employed the building block approach to determine Endeavour Energy's annual revenue requirement. The building block costs, illustrated in Figure 4, include:[26]

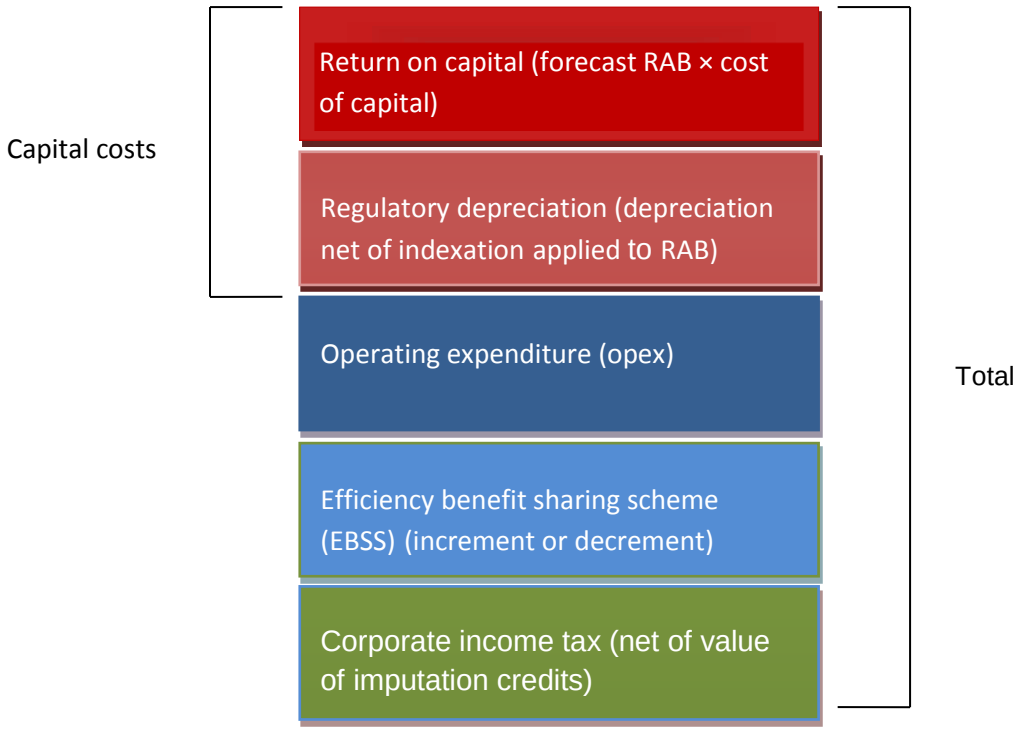
- a return on the Regulatory Asset Base (RAB) (return on capital)
- depreciation of the RAB (return of capital)
- forecast opex

[26] NER cl. 6A.5.4

- increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of the RAB and therefore, the revenue generated from the return on capital and return of capital building blocks.

Figure 4 The building block approach for determining total revenue



The following section summarises our decision by building block and provides our high level reasons and analysis. The attachments provide a more detailed explanation of our analysis and findings.

2.2 Regulatory asset base

The RAB is the value of Endeavour Energy's assets that are used to provide distribution network services. It is the value on which Endeavour Energy earns a return on capital, and a depreciation allowance (return of capital) on assets in its RAB.

We are required to assess Endeavour Energy's proposed opening value for the RAB for each year of the 2015–19 regulatory control period.[27]

Our final decision is to accept Endeavour Energy's revised proposed opening RAB as at 1 July 2014 of $5581.3 million ($ nominal). We forecast a closing RAB at 30 June 2019 of $6859.9 million.

[27] NER, cll. 6.5.1 and S6.2.

The forecast depreciation approach will be used to establish Endeavour Energy's RAB at the commencement of the following regulatory control period on 1 July 2019.

Table 3 sets out our final decision on the roll forward of Endeavour Energy's RAB during the 2009–14 regulatory control period.

Table 3 AER's final decision on Endeavour Energy's RAB for the 2009–14 regulatory control period ($ million, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	3690.0	3940.3	4342.1	4910.3	5346.0
Capital expenditure[a]	423.1	509.4	647.9	581.7	542.4
Inflation indexation on opening RAB	67.2	112.1	147.2	86.6	131.0
Less: straight-line depreciation	239.9	219.7	226.8	232.6	231.5
Closing RAB	3940.3	4342.1	4910.3	5346.0	5787.8
Difference between estimated and actual capex (1 July 2008 to 30 June 2009)					–116.6
Return on difference for 2008–09 capex					–71.2
Closing RAB as at 30 June 2014					5600.1
Meters moved to alternative control services					–18.8
Opening RAB as at 1 July 2014					**5581.3**

Source: AER analysis.

(a) Net of disposals and capital contributions, and adjusted for CPI.

Table 4 sets out our final decision on the roll forward of Endeavour Energy's forecast RAB for the 2014–19 period.

Table 4 AER's final decision on Endeavour Energy's RAB for the 2014–19 period ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	5581.3	5944.3	6223.7	6444.0	6658.5
Capital expenditure[a]	432.3	358.3	310.0	308.2	301.5
Inflation indexation on opening RAB	132.8	141.5	148.1	153.4	158.5
Less: Straight-line depreciation	202.1	220.4	237.8	247.2	258.5
Closing RAB	**5944.3**	**6223.7**	**6444.1**	**6658.5**	**6859.9**

Source: AER analysis.

(a) Net of forecast disposals and capital contributions.

Our assessment involved:

- Rolling forward the opening RAB at 1 July 2009 to determine the closing RAB as at 30 June 2014
- Using our final decision on forecasts of depreciation, capex, disposals and inflation for the 2014–19 period to roll forward Endeavour Energy's forecast RAB for each year of that period.

Endeavour Energy's revised proposal adopted all our draft decision adjustments to roll forward the opening RAB from 1 July 2009 to 1 July 2014. The only change Endeavour Energy made to the draft decision was updating 2013–14 estimated capex with actuals consistent with the annual reporting information for that year. We accept Endeavour Energy's revised opening RAB as at 1 July 2014 in our final decision.

As part of this final decision we also forecast the closing RAB value at 30 June 2019 for Endeavour Energy. We forecast Endeavour Energy's closing RAB to be $6859.9 million ($ nominal). This is lower than forecast by Endeavour Energy and reflects our adjustments to:

- forecast depreciation (attachment 5)
- forecast inflation rate(attachment 3).

Details of our final decision on the value of the RAB are set out in attachment 2.

2.3 Rate of return (return on capital)

The return on capital provides a service provider with revenue to service the interest on its loans and to give a return on equity to shareholders. This building block is calculated as a product of the rate of return and the value of the RAB.[28]

The NER sets out that the rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the distributor in respect of the provision of distribution services.[29] The NER refers to this requirement as the allowed rate of return objective.

We have determined an allowed rate of return for 2014–15 of 6.74 per cent (nominal vanilla[30]). We have not accepted Endeavour Energy's proposed 8.85 per cent return.[31] In accordance with the Guideline, we will update the rate of return annually, consistent with Endeavour Energy's revised proposal and our approach to the return on debt.[32]

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28 NER, cl. 6.5.2(a).

29 NER, cl. 6.5.2(b)

30 The nominal vanilla rate of return formula combines a post-tax return on equity and pre-tax return on debt, for consistency with other building blocks.

31 The rate of return that Endeavour Energy included in its proposal is an indicative value. Its proposal includes provision for the AER to adjust this value based on updated information that was not available when Endeavour Energy submitted its revised proposal.

32 NER, cl. 6.5.2(i)(2).

Accordingly, the rate of return for 2015–16 will be 6.68 per cent. Table 5 sets out the parameters we have used to determine the rate of return.

Table 5 AER's final decision on Endeavour Energy's rate of return (nominal)

	AER decision 2009–14	AER transitional decision 2014–15	Endeavour Energy's revised proposal	AER final decision 2014–15	AER final decision 2015–16	AER final decision 2016–19
Nominal risk free rate (return on equity)[(a)]	5.82%	4.30%	4.77%	2.55%	2.55%	2.55%
Equity risk premium	6.00%	4.55%	5.38%	4.55%	4.55%	4.55%
MRP	6.00%	6.50%	6.56	6.50%	6.50%	6.50%
Equity beta	1.0	0.7	0.82	0.7	0.7	0.7
Nominal post–tax return on equity	11.82%	8.90%	10.15%	7.1%	7.1%	7.1%
Nominal pre–tax return on debt	8.82%	7.50%	7.98%	6.51%	6.40%	Updated annually[(b)]
Gearing	60%	60%	60%	60%	60%	60%
Nominal vanilla WACC	10.02%	8.06%	8.85%	6.74%[(c)]	6.68%	Updated annually[(b)]
Forecast inflation	2.47%	2.50%	2.50%	2.38%	2.38%	2.38%

Source: AER analysis; Endeavour Energy, *Revised regulatory proposal*, 20 January 2015; AER, *Endeavour Energy Transitional Distribution Determination 2014–15*, April 2014; AER, *Statement on updates to NSW distribution determinations following Australian Competition Tribunal decision*, November 2009.

(a) Endeavour Energy's risk free rate estimate was calculated using a long-run historical averaging period of 1883 to 2013. AER final decision risk free rate estimate is based on a 20 business day averaging period from 9 February to 6 March 2015.

(b) The allowed return on debt is to be updated annually and the nominal vanilla WACC will be updated annually to reflect the allowed return on debt. The allowed return on debt for 2015–16 has already been estimated. Return on debt allowances for subsequent years will be estimated based on the formula set out in the Return on Debt Appendix to this attachment.

(c) This rate of return estimate will be used to update the revenues we previously determined for the 2014–15 (transitional) regulatory year.

Our approach

All NER requirements relating to the rate of return are subject to the overall rate of return achieving the allowed rate of return objective,[33] which applies to the overall rate of return. The NER recognises that there may be several plausible answers that could achieve the allowed rate of return objective.[34] We agree with stakeholders that predictability of outcomes in rate of return issues could materially benefit the long term interest of consumers.[35]

We developed our approach prior to the submission of this regulatory proposal. As required by the rate of return framework, in December 2013, we published the Guideline.[36] The Guideline was designed through extensive consultation and included effective and inclusive consumer participation.[37]

Return on debt

Previously, we used an on-the-day approach to determine the return on debt.[38] This is the approach that several Australian regulators continue to use. However, for this decision, we have determined a return on debt estimate that gradually transitions from an on-the-day approach to a trailing average approach.[39] This is consistent with the views most stakeholders expressed during the Guideline development process. We note that Endeavour Energy, supported by some other distributors, did not agree on the transition to the trailing average approach.

Endeavour Energy proposed that we use a backwards looking approach to move from the on-the-day approach to the trailing average approach. This involved using data from the last ten years to set the return on debt for the 2015-19 regulatory control period. We disagree. Instead we have determined a gradual, forward looking transition to a trailing average.[40]

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33 NER, cl. 6.5.2(b).

34 AEMC, *Rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012: National gas amendment (Price and revenue regulation of gas services) Rule 2012*, 29 November 2012, p. 67 (AEMC, *Final rule change determination*, November 2012); AEMC, *Final rule change determination*, November 2012, p. iv, AEMC, *Final rule change determination*, November 2012, p. 38; The High Court of NZ stated: 'In determining WACC, precision is therefore an elusive and perhaps non-existent quality. Setting WACC is, we suggest, more of an art than a science. The use of WACC, in conjunction with RAB values, to set prices and revenue in price-quality regulation gives significance to WACC estimates that may not exist outside this context.' *Wellington International Airport Ltd & Others v Commerce Commission* [2013] NZHC 3289, para. 1189.

35 ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p. 1; AER, *Better regulation: Explanatory statement rate of return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp.185–186.

36 NER, cl. 6.5.2(m).

37 http://www.aer.gov.au/node/18859

38 This involved determining the return on debt by reference to the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the regulatory control period.

39 In broad terms, this means that, over the longer term, the return on debt for any year will represent the average return on debt over the previous ten years.

40 For 2015-16, this involves 100 per cent of the return on debt reflecting the return on BBB+ rated bonds over a 10-40 business day averaging period that occurred as close as practicable to the start of the 2015-16 regulatory year.

As mentioned in section 1.2.1, rate of return is the most material revenue difference between our final decision and Endeavour Energy's revised proposal. We summarise our reasons in some detail below.

We are satisfied that a gradual, forward looking transition to a trailing average approach results in a return on debt that contributes to the rate of return objective. In particular, this approach takes account of any impacts on a benchmark efficient entity or customers that might arise as a result of changing the methodology that is used to estimate the return on debt. This includes impacts that occur across regulatory control periods. In particular, a gradual, forward looking transition:

- Has regard to the impact on a benchmark efficient entity of changing the method for estimating the return on debt
- Promotes efficient financing practices consistent with the principles of incentive based regulation
- Provides a benchmark efficient entity with a reasonable opportunity to recover at least the efficient financing costs it incurs in financing its assets. And as a result it:
    - Promotes efficient investment, and
    - Promotes consumers not paying more than necessary for a safe and reliable network
- Avoids a potential bias in regulatory decision making that can arise from choosing an approach that uses historical data after the results of that historical data are already known
- Avoids practical problems with the use of historical data as estimating the return on debt during the global financial crisis is a difficult and contentious exercise.

Endeavour Energy proposed that we move away from our previous on-the-day approach to setting the return on debt. It proposed that we determine the return on debt using a backwards looking trailing average without any transition to account for the impacts of changing methodologies. Endeavour Energy's proposal is based on its submission that its existing debt financing practices are efficient and reflect those of a benchmark efficient entity.

We do not agree that Endeavour Energy's debt financing practices were efficient from the perspective of a benchmark efficient entity. Endeavour Energy did not take action to manage its interest rate risk arising from its revenue determination process. We consider that the evidence before us indicates that a benchmark efficient entity would have taken action to manage its interest rate risk and this would have resulted in its

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For 2016-17, this will involve 90 per cent of the return on debt reflecting the 2015-16 averaging period and 10 per cent reflecting the 2016-17 averaging period. For 2017-18 this will involve 80 per cent of the return on debt reflecting the 2015-16 averaging period, 10 per cent reflecting the 2016-17 averaging period and 10 per cent reflecting the 2017-18 averaging period. This process will continue until, after 10 years, the entire debt portfolio has been updated and incorporated into the trailing average approach. At that point the transition is complete. This approach is the same as the transitional arrangements we proposed in the rate of return guideline.

actual return on debt being lower at present. If we were to apply Endeavour Energy's proposed approach, consumers would fund an inefficient return on debt allowance. Endeavour Energy's practices may have been appropriate from the perspective of its particular circumstances. However, a key feature of those circumstances is its government ownership, which is not relevant to our task of determining the allowed rate of return of a benchmark efficient entity.

Return on equity

Endeavour Energy agrees with our approach to determining the return on equity. It involves considering all of the information before us, through a six step process as set out in the Guideline (foundation model approach). This includes detailed consideration of a number of financial models for determining the return on equity.[41] Considering all of this material helps inform a return on equity estimate that contributes to the achievement of the allowed rate of return objective.

We consider that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior financial model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. The expert evidence before us indicates that on balance employing our foundation model approach and using the SLCAPM as the foundation model is expected to lead to a rate of return that achieves the allowed rate of return objective.[42]

We also evaluated our point estimate from the SLCAPM against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at a given time.[43] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent which is within the range of other information available to inform the return on equity (see Figure 5). A detailed explanation of our findings on return on equity and this figure can be found in attachment 3.

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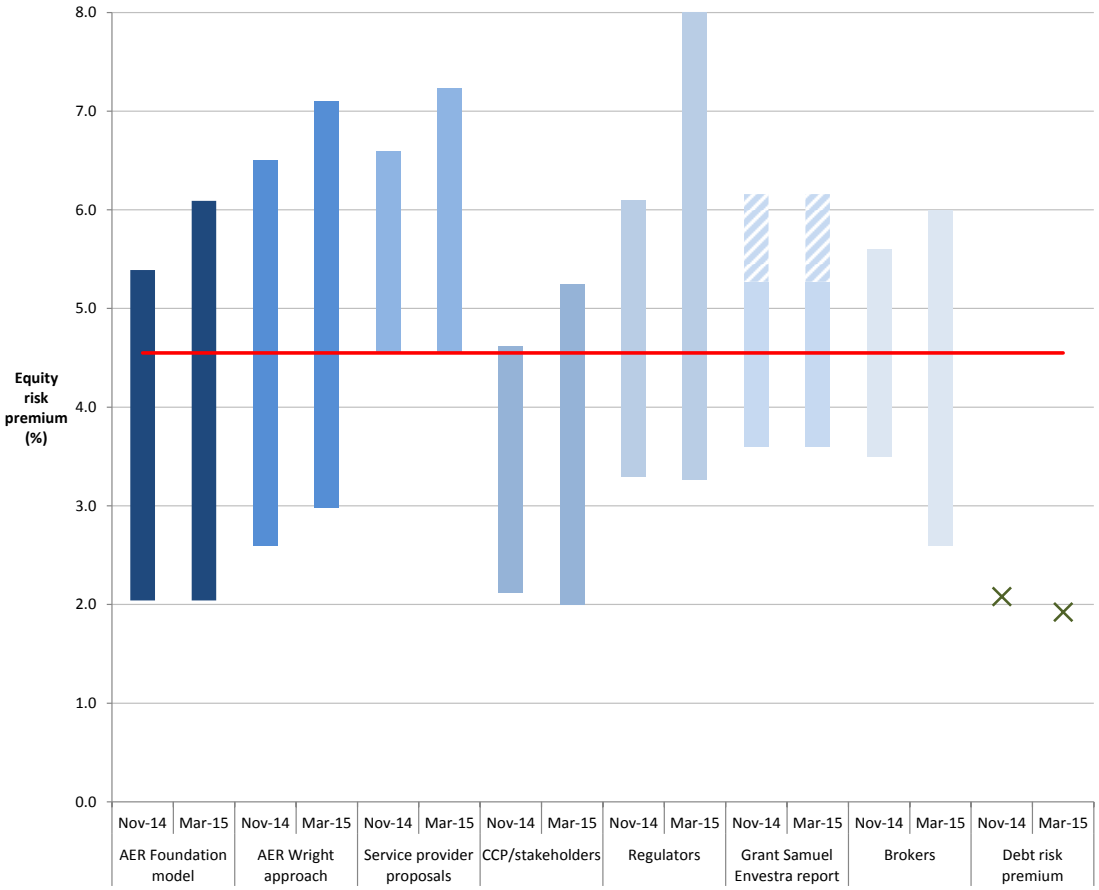
41 NEL, Cl. 6.5.2(e)(1)

42 McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p. 13;and *Return on equity, Report to the AER*, (Updated) April 2015, John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p. 3.

43 Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

Figure 5 Equity risk premium comparison



Source: AER analysis and various submissions and reports.

Notes: The AER foundation model equity risk premium (ERP) range uses the range and point estimate for MRP and equity beta as set out in step three. The calculation of the Wright approach, debt premium, brokers, and other regulators ranges is outlined in Appendices A.1, A.2, A.4, and A.5 respectively.

Grant Samuel's final WACC range included an uplift above an initial SLCAPM range. The lower bound of the Grant Samuel range shown above excludes the uplift while the upper bound includes the uplift and is on the basis that it is an uplift to return on equity. Grant Samuel made no explicit allowance for the impact of Australia's dividend imputation system. We are uncertain as to the extent of any dividend imputation adjustment that should be applied to estimates from other market practitioners. Accordingly, the upper bound of the range shown above includes an adjustment for dividend imputation, while the lower bound does not. The upper shaded portion of the range includes the entirety of the uplift on return on equity and a full dividend imputation adjustment.[44]

The service provider proposals range is based on the proposals from businesses for which we are making final or preliminary decisions in April–May 2015.[45] Equity risk premiums were calculated as the proposed return on equity less the risk free rate utilised in the service provider's proposed estimation approach.

The CCP/stakeholder range is based on submissions made (not including service providers) in relation to our final or preliminary decisions in April–May 2015. The lower bound is based on the Energy Users

[44] Grant Samuel, *Envestra: Financial services guide and independent expert's report*, March 2014, Appendix 3.

[45] ActewAGL, Ausgrid, Directlink, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena Gas Networks, SA Power Networks, TasNetworks, and TransGrid.

Association of Australia submission on NSW distributors revised proposals. The upper bound is based on Origin's submission on ActewAGL's proposal.[46]

2.4 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[47] These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the NER requires that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[48] That is, the revenue allowance granted to a service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

We do not accept Endeavour Energy's proposed value of imputation credits of 0.25. Instead, we adopt a value of imputation credits of 0.4.

Although we have broadly maintained the approach to determining the value of imputation credits set out in the Rate of Return Guideline, we have re-examined the relevant evidence and estimates. This re-examination, and new advice and evidence considered for the first time since the Guideline, led us to depart from the value of 0.5 in the Guideline. Most notably, our updated consideration of the relevant advice and evidence led us to generally lower estimates of the 'utilisation rate' from the 0.7 estimate in the Guideline.

Estimating the value of imputation credits is a complex and imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate and there is a range of evidence relevant to the utilisation rate. This includes:

- The proportion of Australian equity held by domestic investors (the 'equity ownership approach').

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46 Energy Users Association of Australia, *Submission to NSW DNSP Revised Revenue Proposal to AER Draft Determination (2014 to 2019)*, February 2015, pp. 15–16; Origin Energy, *Submission to ActewAGL's regulatory proposal for 2014–19*, August 2014, p. 4.

47 *Income Tax Assessment Act 1997*, parts 3–6.

48 NER, cls 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3, 6A.5.4(a)(4), 6A.5.4(b)(4) and 6A.6.4; NGR, rs 76(c) and 87A.

- The reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics').
- Implied market value studies—there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics, and
- less reliance upon implied market value studies.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- The equity ownership approach, on which we have placed the most reliance, suggests a value between 0.40 and 0.47 when applied to all equity and between 0.31 and 0.44 when applied to only listed equity. Therefore, the overlap of the evidence from the equity ownership approach suggests a value between 0.40 and 0.44.
- The evidence from tax statistics suggests the value could be lower than 0.4. Therefore, with regard to this evidence and the less reliance we place on it, we choose a value at the lower end of the range suggested by the overlap of evidence from the equity ownership approach (that is, 0.4).
- An estimate of 0.4 is reasonable in light of both higher and lower estimates from implied market value studies and the lesser degree of reliance we place on these studies. The service providers submitted evidence to support placing more reliance on SFG's dividend drop off study relative to other implied market value studies. However, we consider that neither the difference from 0.4 of the estimate from this study (0.32) nor any increased reliance we might place on it relative to other implied market value studies are sufficient to warrant an estimate lower than 0.4.

2.5 Regulatory depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). We are required to decide on whether to approve the depreciation schedules submitted by Endeavour Energy.[49] In doing so, we make determinations on the indexation of the RAB and depreciation building blocks for Endeavour Energy's 2014–19 period. The regulatory depreciation allowance is the net total of straight-line depreciation (negative) less the indexation of the RAB (positive).

[49] NER, cl 6.12.1(8).

While we accept Endeavour Energy's approach to determining its regulatory depreciation, our final decision on the forecast inflation rate (attachment 3) results in a different amount of regulatory depreciation than that proposed by Endeavour Energy. Endeavour Energy's revised proposal for regulatory depreciation allowance is $397.4 million ($ nominal) for the 2014–19 period. We have determined a regulatory depreciation allowance of $431.7 million ($ nominal) as shown in Table 6.

Table 6 AER's final decision on Endeavour Energy's depreciation allowance for the 2014–19 period ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Straight-line depreciation	202.1	220.4	237.8	247.2	258.5	1166.0
Less: inflation indexation on opening RAB	132.8	141.5	148.1	153.4	158.5	734.3
Regulatory depreciation	**69.3**	**78.9**	**89.7**	**93.8**	**100.0**	**431.7**

Source: AER analysis.

Details of our final decision on the regulatory depreciation allowance are set out in attachment 5.

2.6 Capital expenditure

Capital expenditure (capex) refers to the capital costs incurred in the provision of network services. The return on and of forecast capex for standard control services are two of the building blocks we use to determine Endeavour Energy's total revenue requirement.

We are satisfied that Endeavour Energy's revised total capex forecast of $1595.84 million ($2013–14) for the 2014–19 period reasonably reflects the capex criteria. We assessed the margin of difference between our alternative estimate and Endeavour Energy's proposed forecast. We consider the margin of difference is not material. Table 7 outlines our final decision.

Table 7 Our final decision on Endeavour Energy's total forecast capex (million $2013–14)

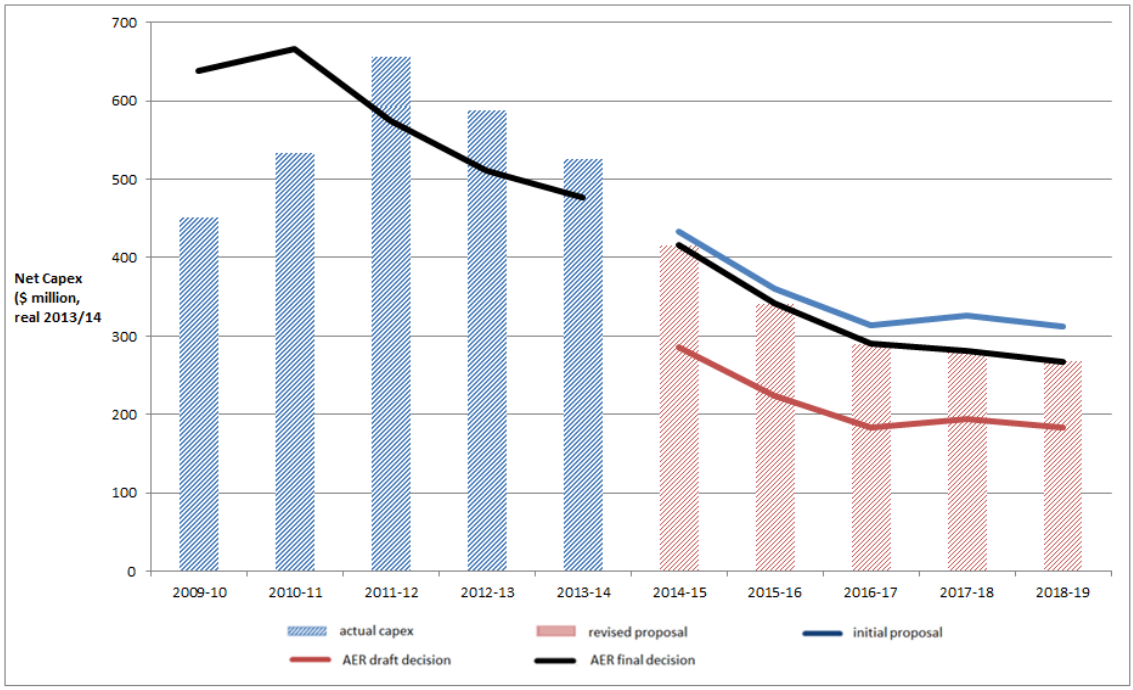
	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Endeavour Energy's proposal	416.18	341.68	290.17	280.46	267.34	1595.84
AER final decision	416.18	341.68	290.17	280.46	267.34	1595.84
Difference	0.00	0.00	0.00	0.00	0.00	0.00
Percentage difference (%)	0.00	0.00	0.00	0.00	0.00	0.00

Source: Endeavour Energy Regulatory Proposal; AER analysis

Note: Numbers may not add up due to rounding.

Figure 6 shows the difference between Endeavour Energy's initial proposal, its revised proposal and our final decision for the 2014–19 period, as well as the actual capex that Endeavour Energy spent during the 2009–14 regulatory control period.

Figure 6 Endeavour Energy's forecast capex, AER draft decision, and actual capex 2009–19



Source: AER analysis

Endeavour Energy submitted a revised capex forecast 11 per cent lower than its initial regulatory proposal. The main reasons for the lower forecasts in its revised proposals are that Endeavour Energy corrected its initial forecasts for data issues and also adopted some of our changes from the draft decision for certain expenditure categories.

In its revised proposal, Endeavour Energy addressed many of the concerns that we raised in our draft decision, adjusting its forecasts for capex. Thus we have accepted its revised proposal for capex. We consider that our overall capex allowance is consistent with the NEO in that our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity. Further, in making our final decision, we have specifically considered the impact our decision will have on the safety and reliability of Endeavour Energy's network. We have approved all capex contained in Endeavour Energy's revised proposal and consider this capex allowance is sufficient that Endeavour Energy will be able to maintain the safety, service quality and reliability of its network consistent with current obligations.

2.7 Operating expenditure

Opex includes forecast operating, maintenance and other non-capital costs incurred in the provision of transmission network services. It includes labour costs and other non-capital costs that Endeavour Energy is likely to require during the 2014–19 period for the efficient operation of its network.

We estimate total forecast opex over the forecast period of $1218.3 million ($2014–15). This is 83.1 per cent of Endeavour Energy's forecast opex. Table 8 shows our final decision on total opex compared to Endeavour Energy's revised proposal.

Table 8 AER final decision and Endeavour Energy's revised proposed total opex ($ million, 2013–14)

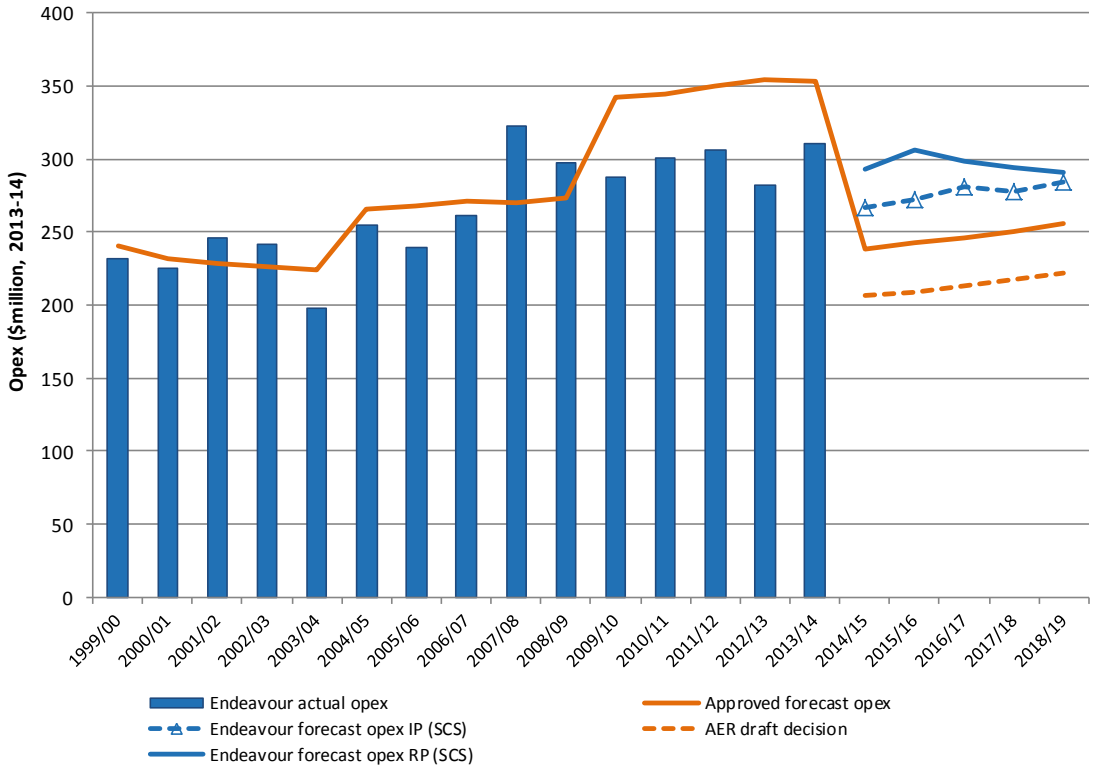
	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Endeavour's initial proposal	263.7	268.4	277.1	274.6	280.2	1364.1
AER draft decision	203.4	206.4	210.2	214.4	219.0	1053.5
Endeavour's revised proposal	289.5	302.5	295.1	291.1	287.3	1465.6
AER final decision	235.8	239.5	243.3	247.5	252.3	1218.3

Source: AER analysis.

Note: Excludes debt raising costs.

Figure 7 shows our final decision compared to Endeavour Energy's revised proposal, its past allowances and past actual expenditure.

Figure 7 AER final decision compared to Endeavour Energy's past and proposed opex ($million, 2013-14)



Attachment 7 sets out our detailed reasons for our final decision on Endeavour Energy's total forecast opex. While we consider that Endeavour Energy's revealed opex still includes inefficiencies, we have determined that they are not materially inefficient for the purposes of developing an alternative forecast that we are satisfied reasonably reflects the opex criteria. On this basis our final decision is to rely on Endeavour Energy's revealed opex as a starting point for forecasting its future opex. We call our starting point our estimate of base opex.

The key differences between our substitute estimate and Endeavour Energy's proposed opex relate to Endeavour Energy's proposed step change for vegetation management. Endeavour Energy considered its revealed opex does not reflect the full cost of complying with its existing standards. It proposed an increase in opex that reflected increased costs associated with meeting its existing standards, and increased overhead expenditure that was allocated to vegetation management as a result of this proposed cost increase.

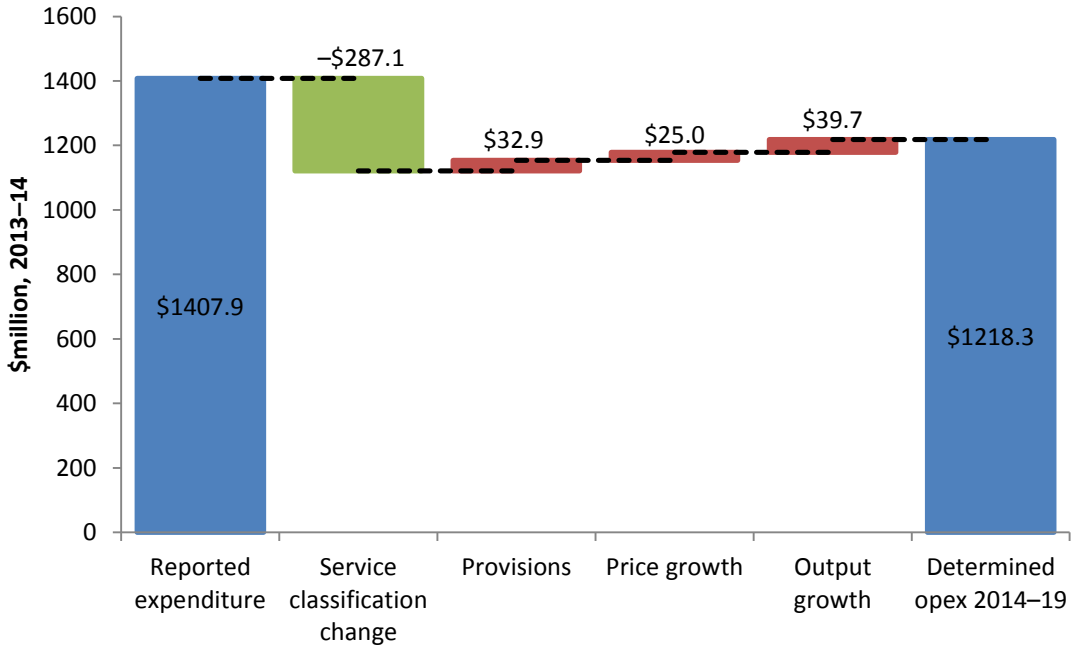
We consider our estimate of base opex is sufficient for Endeavour Energy to meet all of its existing regulatory obligations—including for vegetation management. We consider there is not sufficient evidence that Endeavour Energy requires an additional increase in opex to meet its existing regulatory obligations. Evidence we considered in in reaching our decision included the following:

- Benchmarking of Endeavour Energy's historical opex against other service providers

- Deloitte's findings about the efficiency of all NSW service providers' labour costs and workforce practices
- A Networks NSW review of all NSW service providers' vegetation management practices
- The interactions between with our opex forecasting approach and our incentive scheme for opex, the EBSS.

Figure 8 illustrates how our forecast has been constructed. The starting point on the left is what Endeavour Energy's opex would have been for the 2014–19 period if it was set based on Endeavour Energy's reported opex in 2012–13.

Figure 8 Our final decision opex forecast



2.8 Corporate income tax

The NER require us to make a decision on the estimated cost of corporate income tax for Endeavour Energy's 2014–19 period.[50] The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for Endeavour Energy over the 2014–19 period. It enables Endeavour Energy to recover the costs associated with the estimated corporate income tax payable during that period.

Our final decision is to determine a cost of corporate income tax of $187.4 million ($ nominal) for Endeavour Energy over the 2014–19 period as shown in Table 9. This is instead of Endeavour Energy's revised proposed cost of corporate income tax allowance of $349.2 million ($ nominal).

[50] NER, cl. 6.4.2(a)(4).

Table 9 AER's final decision on Endeavour Energy's cost of corporate income tax allowance for the 2014–19 period ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Tax payable	60.4	57.8	64.5	63.8	65.8	312.3
Less: value of imputation credits	24.2	23.1	25.8	25.5	26.3	124.9
Corporate income tax allowance	**36.2**	**34.7**	**38.7**	**38.3**	**39.5**	**187.4**

Source: AER analysis.

In our final decision we accept Endeavour Energy's revised proposed inputs for the opening tax asset base as at 1 July 2014, and standard and remaining tax asset lives consistent with those approved in our draft decision. However, our lower approved tax allowance reflects amendments made to other inputs that impact the estimated corporate tax allowance, including:

- the value of imputation credits (attachment 4)
- our final decision on other building block components, which affect revenues and therefore the tax calculation. These include forecast opex (attachment 7) and forecast capex (attachment 6).

Details of our final decision on the corporate income tax allowance are set out in attachment 8.

3 Service classification, control mechanisms, and incentive schemes

A range of factors, in addition to the building blocks, affect Endeavour Energy's revenues. These include service classification, the control mechanism, incentive schemes to promote efficiency, and our approach to services charged to individual consumers. This section sets out our approach to some of these issues.

3.1 Service classification and control mechanisms

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

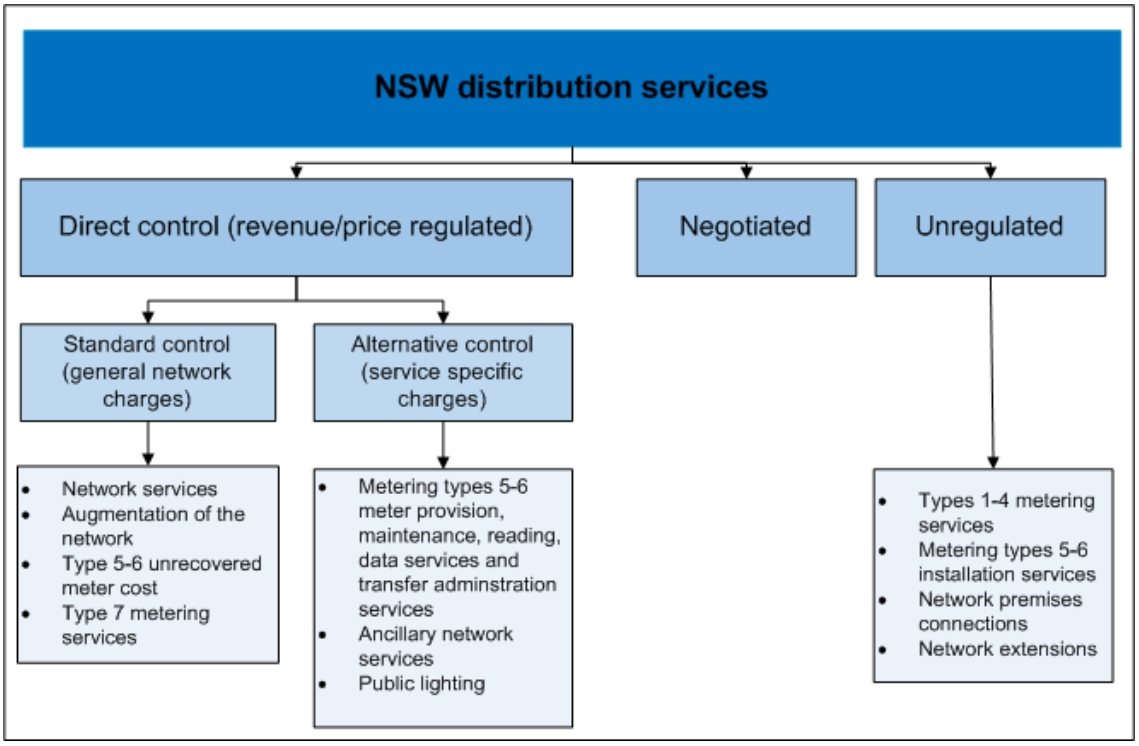
Our final decision is to retain the classification structure set out in our draft decision.

Following consultation with Endeavour Energy we have made minor changes to the definitions of network services (standard control) and metering services (alternative control) to make clear our intended approach to the classification of load control services.

Load control services provided by equipment located outside a type 5 or 6 meter are grouped with network services and classified standard control. Load control services provided by a type 5 or 6 meter are grouped with ancillary metering services and classified alternative control.

Figure 7 shows our final decision on service classifications for the 2015–19 regulatory control period.

Figure 7 AER final decision on 2015–19 service classifications for Endeavour Energy



Source: AER.

Consistent with our draft decision, Endeavour Energy will be subject to a 'revenue cap' form of control for standard control services over the next regulator control period. The control mechanism (which describes how the revenues will vary from year to year) is discussed in Attachment 14. The control mechanism for standard control services is described in mathematical terms and reflects all possible adjustments that might be made to the revenue cap.

3.2 Alternative control services

Alternative control services do not form part of Endeavour Energy's revenue cap. Rather, the prices of these services are set individually. Our final decision is to maintain the approach adopted in our draft decision, that the form of control mechanism to apply to Endeavour Energy's alternative control services will be price caps. Endeavour Energy must demonstrate compliance with the control mechanism through an annual pricing proposal.

The basis of the control mechanism for alternative control services must be determined in our distribution determination.[51]

[51] NER, cl. 6.2.6(b).

Our final decision on the control mechanism for each type of Endeavour Energy's alternative control service is, again, price caps.

We did not approve large upfront metering transfer or exit fees which would be a barrier to competitive entry. Instead, when a customer switches to a competitive metering provider, they will continue to pay a regulated annual charge that recovers the fixed capital costs associated with their past regulated type 5 or 6 metering service. By switching, customers may avoid the operating costs that would be charged by Endeavour Energy for type 5 or 6 metering services.

On 26 March 2015, the AEMC made a draft determination and draft rule in relation to the provision of metering and related services in the NEM. The rule change proposes to expand competition in metering and related services and facilitate a market led roll out of advanced metering technology.[52] We have sought to create a regulatory framework robust enough to handle the transition to competition once the rule change takes effect. This involves having transparent standalone prices for all new/upgraded meter connections and annual charges.

Our final decision does not accept Endeavour Energy's proposed:

- annual metering service charge, because the forecast capital and labour costs do not reasonably reflect the efficient costs of a prudent operator
- price caps for new and upgraded connections, for similar reasons
- transfer or exit fee to switching customers to recover residual metering or administrative costs.

3.3 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. Under our incentive schemes, businesses are given financial rewards where they improve their efficiency and spend less than forecast during the regulatory period. Businesses may also be rewarded for efficient improvements in service quality, or be given an allowance to investigate and conduct demand management projects.

We apply incentive schemes to regulated businesses at the time of making our determinations. We decide whether to apply a particular scheme, depending on the circumstances.

The AER's four incentive schemes are:

- The efficiency benefit sharing scheme (EBSS)
- The capital expenditure sharing scheme (CESS)

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[52] AEMC, Draft Rule Determination, National Electricity Amendment (Expanding competition in metering related services) Rule 2015, 26 March 2015.

- The service target performance incentive scheme (STPIS)
- The demand management incentive scheme (DMIS)

3.3.1 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) provides an additional incentive for service providers to pursue efficiency improvements in opex. It is a key component of incentive regulation under the NER.

Because opex is largely recurrent and predictable, opex in one period is often a good indicator of opex in the next period (step changes provide for increases where this is not the case). Where a service provider is relatively efficient, we use the actual opex it incurred in a chosen base year of the regulatory control period (in this case 2012–13) to forecast opex for the next regulatory control period. We call this the "revealed cost approach".

To encourage a service provider to become more efficient during the regulatory control period it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. This is supplemented by the EBSS which allows the service provider to retain efficiency savings and efficiency losses for a longer period of time. In total these rewards and penalties work together to provide a continuous incentive for a service provider to pursue efficiency gains over the regulatory control period. The EBSS also discourages a service provider from incurring opex in the expected base year in order to receive a higher opex allowance in the following regulatory control period.[53]

In contrast to our draft decision, our final decision is that the EBSS will apply to Endeavour Energy in the 2015–19 regulatory control period.[54] We have made this decision because of our forecasting approach to opex and that having EBSS in place will increase the possibility that Endeavour Energy will become more efficient over time.

3.3.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for network service providers whose capex becomes more efficient throughout the regulatory period and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

As part of the Better Regulation Program we consulted on and published the Capital Expenditure Incentive Guideline, which sets out version 1 of the CESS.[55] The CESS approximates efficiency gains and efficiency losses by calculating the difference

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53 These concepts are explained more fully in the explanatory statement to the EBSS, AER, *Efficiency benefit sharing scheme for electricity network service providers - explanatory statement*, November 2013.

54 This also means that expenditure will be subject to the EBSS in the 2014–15 regulatory control period.

55 AER, *Capex incentive guideline*, Nov 2013, pp. 5–9.

between forecast and actual capex. It shares these gains or losses between service providers and consumers.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

Application of the CESS is not dependent on whether we accept Endeavour Energy's revised opex and capex proposals. In this way the CESS is different from the EBSS. The EBSS is intrinsically linked to the revealed cost forecasting approach for opex. If we do not use a revealed costs approach for forecasting opex in the future, there is not a strong reason to apply the current version of the EBSS. The CESS is not predicated on addressing incentives resulting from a revealed cost forecasting approach. The purpose of the CESS is to provide a continuous incentive to deliver efficient overall capex and to share the benefits of capex efficiency gains (or costs of capex efficiency losses) between the distributor and consumers. The way in which capex underspends and overspends are shared occurs independently of how the EBSS applies, and independently of the precise amount of total forecast capex.[56]

We will apply version 1 of the CESS, as set out in the Capital Expenditure Incentives Guideline, to Endeavour Energy in the 2015–19 regulatory control period.

Attachment 10 sets out our reasons for our final decision on the CESS.

3.3.3 Service target performance incentive scheme

We will apply the s–factor component of our national STPIS to Endeavour Energy for the 2015–19 regulatory control period. We will not apply the GSL component to Endeavour Energy as the existing NSW GSL arrangements will continue to apply.

The national STPIS is intended to balance the incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to distributors to maintain and improve service performance (where customers are willing to pay for these improvements).[57] Hence, the STPIS also provides an incentive for distributors to invest in further reliability improvements (via additional capex or opex) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate. Importantly, the

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[56] For capex, the sharing of underspends and overspends happens at the end of each regulatory control period when we update a network service provider's RAB to include new capex. If a network service provider spends less than its approved forecast during a period, it will benefit within that period. Consumers benefit at the end of that period when the RAB is updated to include less capex compared to if the service provider had spent the full amount of the capex forecast.

[57] AER, *Electricity distribution network service providers—service target performance incentive scheme*, 1 November 2009. (AER, *Electricity distribution STPIS*, Nov 2009).

distributor will only receive a financial reward after actual improvements are delivered to the customers.

In conjunction with CESS and EBSS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex and opex are achieved efficiently, rather than at the expense of service levels to customers.

In setting the STPIS performance targets, we have considered both completed and planned reliability improvements expected to materially affect network reliability performance. By setting the performance targets in such a way, any incentive a distributor may have to reduce the capex at the expense of target service levels should be curtailed by the STPIS financial penalties.

3.3.4 Demand management incentive scheme

The current DMIS for the NSW distributors includes two components—the demand management innovation allowance (DMIA) and the D-factor. The DMIA is a capped allowance for distributors to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A provides for an innovation allowance to be incorporated into each distributor's revenue allowance for opex each year of the regulatory control period.
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A.
- The D-factor offers compensation for both the costs and foregone revenue incurred from demand management projects.

We have determined to continue Part A of the DMIA but we will not apply either Part B of the DMIA or the D-Factor scheme for Endeavour Energy in the 2015–19 regulatory control period. This is consistent with our draft decision.[58]

[58] AER, *Draft decision: Endeavour Energy distribution determination 2015–19,* November 2014, Attachment 12, pp 7 & 8 (AER, Draft Decision, November 2014).

4 Regulatory framework

The NEL and the NER provide the regulatory framework under which we operate. These set out how we must assess a regulatory proposal and make our decision. In this section we set out some key aspects of this framework.

The NEO is the central feature of the regulatory framework. The NEO 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—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[59]

The NEL also includes the revenue and pricing principles (RPP), which support the NEO.[60] As the NEL requires,[61] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
>   - as the case requires, distribution determination or transmission determination; or

59 NEL, s. 7.
60 NEL, s. 7A.
61 NEL, s. 16(2).

- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or

- in the Rules.

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 the direct control network service to which that price or charge relates.

Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

Consistent with Energy Ministers' views we set revenue allowances to balance all of the elements of the NEO and consider each of the RPPs are equally vital.[62]

Chapter 6A of the NER provides specifically for the economic regulation of distributors. It includes detailed rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[63] The AEMC has made clear that, in relation to key aspects of revenue, the rules guide the AER. These rules do not dictate any specific regulatory outcome.[64] For example, the AEMC has said:

> Some stakeholders appear to have understood the objectives as imposing on the regulator a requirement and that failure to comply with this would mean the regulator is in breach of the rules. This is not the case. Although the language of an obligation is used in some objectives, it is not necessarily expected that the substance of the objective will always be fully achieved, but rather the regulator should be striving to achieve the objective as fully as possible.

Given this framework, we consider the NEO and how to achieve it throughout our decision making processes.

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62 Hansard, SA House of Assembly, 27 September 2007 pp. 965. Hansard, SA House of Assembly, 26 September 2013 p. 7173.

63 NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* p. 8.

64 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 33-34
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp 35-6.

4.1 Understanding the NEO

Energy Ministers have provided us with a substantial body of explanation that guides our understanding of the NEO.[65] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[66]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value at least cost in the long run.[67] In most industries, competition creates this outcome. Competition drives suppliers to develop their offerings to attract customers. Where a supplier's offering is not attractive it risks being displaced by other suppliers.

However, in the energy networks industry the usual competitive disciplines do not apply. Distributors are largely natural monopolies. In addition, many of the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the quality, reliability and price the distributors offer.

The NEL and NER aim to remedy the absence of competition by providing that we, as regulator, make decisions that are in the long term interests of consumers. In particular, we might need to require the distributors to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory judgement to balance the NEO's various factors.

It is important to recognise that there are a number of plausible outcomes that may contribute to the achievement of the NEO. The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[68] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO to a satisfactory extent. For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[69] This could have significant longer term pricing implications for those consumers who continue to use network services.

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65 Hansard, SA House of Assembly, 9 February 2005 pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007 pp. 963–972.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171–7176.

66 Hansard, SA House of Assembly, 26 September 2013 p. 7173.

67 Hansard, SA House of Assembly, 9 February 2005 p. 1452.

68 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50

69 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[70] and could have adverse consequences for safety, security and reliability of the network.

4.2 The 2012 framework changes

This is the first decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were amended to provide greater emphasis on the NEO and greater discretion to us.[71] The amended NER allow, and the AEMC has encouraged, us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs.[72] Also one of the purposes of these changes was to give consumers a clearer and more prominent role in the decision making process.[73]

In 2013, the NEL was changed with similar aims in mind. The long term interests of consumers are a key focus of the changes.[74] The changes also support analysing the decision *as a whole* in light of the NEO.[75]

The NEL now requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision.[76] It also anticipates the possibility of two or more decisions that will or are likely to contribute to the achievement of the NEO. It requires that, in those cases, we must make the decision we are satisfied will or is likely to contribute to the

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70 NEL, s. 7A(6).

71 NEL, ss. 16(1)(d) and 71P(2a)(c).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. i, iii, iv, vi, vii, 8, 24 32, 36, 38, 45, 49, 67, 68, 90, 96 106, 112 and 113.
Hansard, SA House of Assembly, 26 September 2013 p. 7172.

72 For example, NER, cl. 6.5.2(b), 6.5.6(a), 6.5.7(a)
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. xi, 10, 19, 32 and 35.

73 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* esp. pp. 166–170.

74 Hansard, SA House of Assembly, 26 September 2013 p. 7171.

75 NEL, ss. 2, 16, 71A and 71P which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171 and 7173; See also NEL, ss. 2, 16 and 71A which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
SCER, *Regulation Impact Statement – Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks*' 6 June 2013 pp. i, ii, 6–7, 10, 36, 41 and 76.

76 NEL, s. 16(c).

achievement of the NEO to the greatest degree.[77] The NER requires that we provide reasons for our decisions.[78]

The NEL does not prescribe how we are to apply these overarching requirements and so in applying them, we have exercised our regulatory judgement.

We have done so by determining revenue in accordance with the detailed provisions in the NER. This assessment is in each of our attachments. As part of that assessment, and in accordance with the NEL requirements, we identify and assess the interrelationships between the constituent components of our final decision. In the following sections, we explain our approach to evaluating these interrelationships and then set out how we assessed what will contribute to the achievement of the NEO to the greatest degree. Section 1 of this overview demonstrates how we have applied these approaches for this decision.

4.2.1 Interrelationships

A distribution determination is a complex decision and must be considered as such. Considering constituent components in isolation ignores the importance of these interrelationships between the components and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[79] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see Attachment 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see Attachments 3, 4 and 8).
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see Attachments 6 and 7).
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements (see Attachments 6 and 7).

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77 NEL, s. 16(1)(d).

78 NER, cl. 6.11.2(c).

79 SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013 p. 6

- the distributor's approach to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (see Attachment 6).

We have considered interrelationships in our analysis of the constituent components of our decision. These considerations are explored in the relevant attachments.

5 Process

The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of this decision.[80]

Below we set out the process we have followed leading up to Endeavour Energy's submission its regulatory proposal, to ensure that we have fully taken into account all views.

5.1 Better Regulation program

Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[81] The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[82]

The resulting guidelines support our decision making framework as set out in section 16 of the NEL. Our consultation and engagement gives us confidence the approaches set out in the guidelines, which we have applied in this decision, will result in decisions that will or are likely to contribute to the achievement of the NEO. Our Better Regulation guidelines are available on our website and include:[83]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline
- Shared Assets Guideline
- Confidentiality Guideline.

5.2 Our engagement during the decision making process

Effective consultation with stakeholders is essential to the performance of our regulatory functions. In summary, throughout the review process, we engaged with stakeholders by:

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80 NEL, s. 16(1)(b)

81 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

82 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

83 http://www.aer.gov.au/Better-regulation-reform-program

- holding monthly meetings with Endeavour Energy to discuss issues relevant to this decision. These meetings commenced in October 2011 to discuss the framework and approach. The meetings continued throughout our decision making process.
- establishing the Consumer Challenge Panel (CCP) to assist us to make better regulatory determinations by providing input on issues of importance to consumers
- considering 21 submissions on Endeavour Energy's regulatory proposal and 30 submissions on Endeavour Energy's revised proposal
- publishing an issues paper to help stakeholders engage with, and meaningfully respond to issues in Endeavour Energy's regulatory proposal that we considered material to consumers
- publishing a consultation paper on alternative mechanism for the recovery of the residual metering capital costs to seek stakeholder views
- hosting a public forums in Sydney on 10 July 2014 and 8 December 2014 so stakeholders could question the AER, the CCP and Endeavour Energy on the regulatory proposal and our draft decision
- having Endeavour Energy present its revenue proposal to the AER Board on 1 August 2014, so questions could be raised and key issues explained
- having the CCP present its advice in response to Endeavour Energy's regulatory proposal and revised proposal to the AER Board
- convening monthly meetings between the CCP and AER staff to discuss key issues
- ongoing formal and informal jurisdictional consumer forums from February 2012
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of Endeavour Energy's regulatory proposal
- having ongoing discussions with Endeavour Energy about its regulatory proposal. In particular, our consultants and AER staff met with Endeavour Energy to discuss operating expenditure, augmentation capital expenditure, and replacement capital expenditure. During this process, AER staff and our consultants considered over 60 responses to information requested from Endeavour Energy.
- hosting a workshop on treatment of metering exit fees on 11 September 2014
- meeting with the NSW Public Interest Advocacy Centre and other stakeholders to discuss their submissions in detail.

We investigated Endeavour Energy's proposal by engaging with our consultants and visiting Endeavour Energy at its offices. AER staff, including our technical advisors and EMCa directly engaged with Endeavour Energy staff involved in developing and managing the network, and tested material and information which underpins its revenue proposal.

A list of all submissions is at Appendix B.

6 Next steps

Following publication of this final decision, Endeavour Energy will submit a 2015–16 pricing proposal. This pricing proposal will incorporate the revenues approved in this final decision into network prices from 1 July 2015.

As this decision is a reviewable regulatory decision under the NEL, Endeavour Energy has the right to the Australian Competition Tribunal for a review of the final decision. Endeavour Energy may also apply for a review of the decision in the Federal Court.

Appendix A – Constituent decisions

Our final distribution determination is predicated on the following decisions (constituent decision):[84]

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to Endeavour Energy for the 2015–19 regulatory control period (listed by service group): • Standard control services include network services, augmentation of the network, type 5 and 6 unrecovered meter cost and type 7 metering services • Alternative control services include metering types 5 and 6 provision, maintenance, reading, data services and transfer administration services, ancillary network services and public lighting • Unregulated services includes type 1 to 4 metering services, metering types 5 and 6 installation services, network premises connections, network extensions.
In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in Endeavour Energy's building block proposal. Our final decision on Endeavour Energy's annual revenue requirement for each year of the 2014–19 period is set out in Attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Endeavour Energy's proposal that the subsequent regulatory control period will commence on 1 July 2015. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Endeavour Energy's proposal that the length of the subsequent regulatory control period will be four years from 1 July 2015 to 30 June 2019.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER accepts Endeavour Energy's proposed total forecast capital expenditure of $1595.84 million ($2013–14). This is discussed in Attachment 6 of the final decision.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept Endeavour Energy's proposed total forecast operating expenditure inclusive of debt raising costs of $1482.7 million ($2013–14). Our substitute estimate of Endeavour Energy's total forecast opex for the 2014–19 period is $1233.5 million ($2013–14). This is discussed in Attachment 7 of the draft decision.
In accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination.
Endeavour Energy did not include any proposed contingent projects in its regulatory proposal for the 2015–19 regulatory control period. Therefore, • in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors • in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects • in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.
In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the 2014–15 regulatory year in accordance with clause 6.5.2 is not to accept Endeavour Energy's proposal of 8.85 per cent. Our decision on the allowed rate of return for 2014–15 and 2015–16 regulatory years are 6.74 and 6.68 per cent, respectively as set out in Table 1 of Attachment 3 of the final decision. The rate of return for the remaining regulatory years 2016–19 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which

[84] NER, cl. 6.12.1.

incorporates annual updating of the allowed return on debt.

In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 of the final decision.

In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in attachment 4 of the final decision.

In accordance with clause 6.12.1(6) the AER's decision on Endeavour Energy's regulatory asset base as at 1 July 2014 in accordance with clause 6.5.1 and schedule 6.2 is $5581.3 million. This is set out in attachment 2 of the final decision.

In accordance with clause 6.12.1(7) the AER does not accept Endeavour Energy's proposed corporate income tax of $349.2 million ($ nominal). Our decision on Endeavour Energy's corporate income tax is $187.4 million ($ nominal). This is set out in at attachment 8 of the final decision.

In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by Endeavour Energy. This is set out in Attachment 5 of the final decision.

In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme is to apply:

- In accordance with clause 6.12.1(9) of the NER, the AER's final decision is that expenditure incurred by Endeavour Energy will be subject to version 2 of the EBSS in the 2015–19 regulatory control period. This is set out in attachment 9 of the final decision.
- In accordance with clause 6.12.1(9) of the NER, we will apply the CESS as set out in version 1 of the capital expenditure incentives guideline to Endeavour Energy in the 2015–19 regulatory control period.
- In accordance with clause 6.12.1(9) of the NER, we will apply our Service Target Performance Incentive Scheme (STPIS) to Endeavour Energy for the 2015-19 regulatory control period.
- We will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. We will also apply the customer service telephone answering parameter. We will not apply a guaranteed service level scheme as Endeavour Energy must comply with its existing NSW jurisdictional guaranteed service level scheme.
- A beta of 2.5, using the Box-Cox transformation method, will be used to calculate the major event day boundary.
- Our decision on the SAIDI and SAIFI performance targets and incentive rates to apply to Endeavour Energy in the 2015-20 regulatory control period are set out in tables 11-1 and 11-2 of attachment 11 of this final decision.
- Our decision on the customer service component performance target and incentive rate are set out in section 11.4.5 of attachment 11 of this final decision.
- The revenue at risk for Endeavour Energy will be capped at ±2.5 per cent. Within this there will be a cap of ±0.25 per cent on the telephone answering parameter for performance.
- The value of St for 2015-16 and 2016-17 regulatory years shall be zero. The value for St from 2017-18 onwards shall be calculated in accordance with appendix C of the Service Target Performance Incentive Scheme, November 2009.

  Note: The meaning for year "t" under the price control formula for this determination is different to that in Appendix C of STPIS. Year "t+1" in Appendix C of STPIS is equivalent to year "t" in the price control formula of this decision.
- The AER has determined to continue Part A of the Demand Management Innovation Allowance (DMIA) but will not apply either Part B of the DMIA or the D-factor scheme for Endeavour Energy in the 2015–19 regulatory control period.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.

In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Endeavour Energy for any given regulatory year is the total annual revenue (TAR) for distribution services for that regulatory year plus any adjustment required to move the DUoS under/over account to zero. This is discussed at attachment 14.

In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control

services is to apply price caps. This is discussed in attachment 16.

In accordance with clause 6.12.1(13), to demonstrate compliance with its distribution determination, the AER's decision is Endeavour Energy must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal.

In accordance with clause 6.12.1(14) the AER's decision on the additional pass through events that are to apply is to not to accept the nominated pass through events as drafted by Endeavour Energy. The AER substitutes its own definitions for the following events:

- insurance cap event
- insurer's credit risk
- terrorism event
- natural disaster event.

In accordance with clause 6.12.1(15) the AER's decision is to approve Endeavour Energy's proposed negotiating framework. The negotiating framework that is to apply to Endeavour Energy is set out at attachment 17 of the final decision.

In accordance with clause 6.12.1(16) the AER's decision is to apply the negotiated distribution services criteria published in June 2014 to Endeavour Energy. This is set out is at attachment 17 of the final decision.

In accordance with clause 6.12.1(17) the AER's decision on the procedures for assigning retail customers to tariff classes not to accept Endeavour Energy's proposed procedure. The AER's decision on the procedures for assigning retail customers to tariff classes is set out at attachment 14 of the final decision.

In accordance with clause 6.12.1(18) the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of Endeavour Energy's regulatory control period (1 July 2019). This is discussed in Attachment 2 of the final decision.

In accordance with clause 6.12.1(19) the AER's decision on how Endeavour Energy is to report to the AER on its recovery of designated pricing proposal charges is Endeavour Energy is to set these out in its annual pricing proposal. The AER accepts Endeavour Energy's proposed methodology however does not accept the adjustments to be made to subsequent pricing proposals to account for under and over recovery of charges. This is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(20) the AER's decision is we require Endeavour Energy to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 14 of the final decision.

In accordance with clause 6.12.1(21) the AER approves the connection policy as proposed by Endeavour Energy in its revised proposal. This is set out in attachment 18 of the final decision.

Appendix B – List of submissions

We received 21 submissions in response to Endeavour Energy's regulatory proposal as listed below:

	Submission from	Date received	Submission on
1	Energy Australia	08/08/2014	NSW DNSPs
2	Energy Retailers Association of Australia (ERAA)	08/08/2014	NSW DNSPs
3	AGL	08/08/2014	NSW DNSPs
4	EnerNOC Pty Ltd	08/08/2014	NSW DNSPs
5	Clean Energy Council (CEC)	08/08/2014	NSW DNSPs
6	Networks NSW	08/08/2014	NSW DNSPs
7	Energy Markets Reform Forum (EMRF) – EMRF is an affiliate of Major Energy Users Inc (MEU)	08/08/2014	NSW DNSPs
8	Energy Users Association of Australia (EUAA)	10/08/2014	NSW DNSPs
9	PIAC	08/08/2014	NSW DNSPs
10	Vector Limited	08/08/2014	NSW DNSPs
11	EUAA	08/08/2014	NSW DNSPs
12	Ethnic Communities' Council of NSW (ECC)	07/08/2014	NSW DNSPs
13	Council of Social Service of NSW (NCOSS)	07/08/2014	NSW DNSPs
14	National Generators Forum	01/07/2014	NSW DNSPs
15	Origin Energy	08/08/2014	NSW DNSPs
16	Consumer Challenge Panel (sub-panel1)	12/08/2014	NSW DNSPs
16	Simply Energy	14/08/2014	NSW DNSPs
17	Total Environment Centre	14/08/2014	NSW DNSPs
18	UnitingCare Australia	03/09/2014	NSW DNSPs
19	TRANS TASMAN Energy Group (to represent combined interests of Endeavour Energy Supplied Councils)	11/08/2014	Endeavour Energy
20	Wollongong City Council	08/08/2014	Endeavour Energy
21	TRSNS TASMAN Energy Group - Camden Council (Confidential and public versions)	11/08/2018	Endeavour Energy

We received 30 submissions in response to our draft decision and Endeavour Energy's revised proposal as listed below:

	Submission from	Date received	Submission on
1	Andrew Murphy	13/01/2015	NSW DNSPs
2	CitiPower and Powercor	06/02/2015	NSW DNSPs
3	Jemena Limited	06/02/2015	NSW DNSPs
4	SA Power Network	06/02/2015	NSW DNSPs
5	United Energy	06/02/2015	NSW DNSPs
6	United Energy and Multinet	06/02/2015	NSW DNSPs
7	TasNetworks	11/02/2015	NSW DNSPs
8	Ethnic Communities Council of NSW	11/02/2015	NSW DNSPs
9	The Greens (John Kaye MP)	13/02/2015	NSW DNSPs
10	Professionals Australia	13/02/2015	NSW DNSPs
11	Energy Retailers Association of Australia	13/02/2015	NSW DNSPs
12	Spark Infrastructure	13/02/2015	NSW DNSPs
13	AUSNet	12/02/2015	NSW DNSPs
14	Vector Limited	13/02/2015	NSW DNSPs
15	EnerNOC	13/02/2015	NSW DNSPs
16	Total Environment Centre	13/02/2015	NSW DNSPs
16	Energy Australia	13/02/2015	NSW DNSPs
17	EUAA	13/02/2015	NSW DNSPs
18	Institute for Sustainable Futures	13/02/2015	NSW DNSPs
19	Joy Llewellyn-Smith	19/02/2015	NSW DNSPs
20	Council of Social Service of NSW	13/02/2015	NSW DNSPs
21	Networks NSW	13/02/2015	NSW DNSPs
22	The National Institute of Economic and Industry Research	12/02/2015	NSW DNSPs
23	Origin Energy	15/02/2015	NSW DNSPs
24	Public Interest Advocacy Council	14/02/2015	NSW DNSPs
25	RARE Infrastructure	13/02/2015	NSW DNSPs
26	The McKell Institute	13/02/2015	NSW DNSPs
27	AGL	15/02/2015	NSW DNSPs
28	CCP	16/02/2015	NSW DNSPs
29	ENA	13/02/2015	NSW DNSPs
30	Ergon Energy	16/02/2015	NSW DNSPs